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Evaluation of preformed particle gel treatment using homogeneous and heterogeneous models

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EVALUATION OF PREFORMED PARTICLE GEL TREATMENT USING HOMOGENEOUS AND HETEROGENEOUS MODELS

by

HILARY OGOCHUKWU ELUE

A THESIS

Presented to the Faculty of the Graduate School of the MISSOURI UNIVERSITY OF SCIENCE AND TECHNOLOGY

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Approved by

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Ralph Flori
ABSTRACT

This research investigates the effects of preformed particle gel (PPG) in remedying the problems of excess water production and low oil recovery of heterogeneous reservoirs by placing the PPG in the high-permeability layer, thus diverting displacing brine to the unswept low permeability layer. This investigation was completed with three tasks.

The first task was to evaluate the PPG swelling kinetics and strength as a function of concentration of brine. The result of this task indicate that PPG prepared with low concentration of brine swells more, becomes weaker, more deformable than PPG prepared with high concentration of brine.

The second task is to investigate the injection pressure and permeability reduction factors caused by the injection of PPG on a homogeneous coreflooding model. The results of this task indicates that PPG swollen with low concentration of brine caused higher injection pressure and permeability reduction than PPG swollen with high concentration of brine. This permeability reduction was more significant with higher permeability sandstone cores.

The third task evaluated the effect of PPG on profile modification, water cut reduction and oil recovery using parallel heterogeneous sandpack model. The results of this task indicates that the injection profiles of the different permeability contrast were modified after PPG injection. The water cut reduced during PPG injection and oil recovery from the unswept low permeability layers were improved after PPG injection. However, the total oil recovery increased more as the permeability contrast between the low and high permeability sandpacks reduces.
ACKNOWLEDGMENTS

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Finally, I greatly appreciate the support of my brother Anthony and my parents for their love and blessings.
# TABLE OF CONTENTS

<table>
<thead>
<tr>
<th>Section</th>
<th>Title</th>
<th>Page</th>
</tr>
</thead>
<tbody>
<tr>
<td>1. INTRODUCTION</td>
<td>1. INTRODUCTION TO ENHANCED OIL RECOVERY</td>
<td>3</td>
</tr>
<tr>
<td>2. LITERATURE REVIEW</td>
<td>2.1. INTRODUCTION TO ENHANCED OIL RECOVERY</td>
<td>3</td>
</tr>
<tr>
<td></td>
<td>2.2. EXCESS WATER PRODUCTION</td>
<td>4</td>
</tr>
<tr>
<td></td>
<td>2.3. CAUSES OF EXCESS WATER PRODUCTION</td>
<td>5</td>
</tr>
<tr>
<td></td>
<td>2.3.1. Reservoir Related Problems</td>
<td>5</td>
</tr>
<tr>
<td></td>
<td>2.3.2. Wellbore Problems</td>
<td>6</td>
</tr>
<tr>
<td></td>
<td>2.4. METHODS TO REDUCE EXCESS WATER PRODUCTION</td>
<td>7</td>
</tr>
<tr>
<td></td>
<td>2.4.1. Mechanical Methods</td>
<td>8</td>
</tr>
<tr>
<td></td>
<td>2.4.2. Chemical Methods</td>
<td>8</td>
</tr>
<tr>
<td></td>
<td>2.5. GEL TREATMENT</td>
<td>9</td>
</tr>
<tr>
<td></td>
<td>2.6. CONFORMANCE CONTROL</td>
<td>12</td>
</tr>
<tr>
<td></td>
<td>2.6.1. Gels used for Conformance Control Treatment</td>
<td>12</td>
</tr>
<tr>
<td></td>
<td>2.6.1.1 In-situ gels systems</td>
<td>12</td>
</tr>
<tr>
<td></td>
<td>2.6.1.2 Preformed gel systems</td>
<td>14</td>
</tr>
<tr>
<td></td>
<td>2.7. GELS PROPAGATION THROUGH POROUS MEDIA</td>
<td>18</td>
</tr>
<tr>
<td>3. EVALUATION OF PPG TREATMENT USING HOMOGENEOUS MODEL</td>
<td>3.1. INTRODUCTION</td>
<td>23</td>
</tr>
<tr>
<td></td>
<td>3.2. EXPERIMENT MATERIALS</td>
<td>23</td>
</tr>
<tr>
<td></td>
<td>3.2.1. Preformed Particle Gel (PPG)</td>
<td>23</td>
</tr>
<tr>
<td></td>
<td>3.2.1.1 Preparation of swollen PPG sample</td>
<td>24</td>
</tr>
</tbody>
</table>
3.2.2. Brine
3.2.3. Berea Sandstone Core
3.2.4. HAAKE™ RheoScope

3.3. EXPERIMENTAL SETUP

3.4. EXPERIMENTAL PROCEDURE
3.4.1. PPG Swelling Ratio Procedures
3.4.2. Core-flooding Experiment Procedures

3.5. RESULTS ANALYSIS AND DISCUSSION
3.5.1. Evaluation of PPG Swelling Ratio and Gel Strength
3.5.2. Evaluation of Permeability Reduction

4. EVALUATION OF PPG TREATMENT USING HETEROGENEOUS MODEL
4.1. INTRODUCTION
4.2. EXPERIMENTAL MATERIALS
4.2.1. Preformed Particle Gel (PPG)
4.2.2. Sand Grains
4.2.3. Brine
4.2.4. Mineral Oil

4.3. EXPERIMENTAL SETUP

4.4. EXPERIMENTAL PROCEDURES
4.4.1. Preparing the Sandpack:
4.4.2. Measuring Porosity:
4.4.3. Measuring Absolute Permeability:
4.4.4. Oil Saturation Procedures:
4.4.5. Water flood before PPG Injection:
4.4.6. PPG Injection Procedures:
4.4.7. WaterFlood after PPG Injection Procedures:

4.5. PERMEABILITY CONTRAST

4.6. RESULTS ANALYSIS AND DISCUSSIONS
4.6.1. Permeability Contrast of 44.
<table>
<thead>
<tr>
<th>Figure</th>
<th>Page</th>
</tr>
</thead>
<tbody>
<tr>
<td>2.1. Three stages oil production (Green &amp; Willhite, 1998)</td>
<td>4</td>
</tr>
<tr>
<td>2.2. Reservoir Sources (Bailey et al., 2000; Seright et al., 2003)</td>
<td>6</td>
</tr>
<tr>
<td>2.3. Wellbore Sources (Bailey et al., 2000)</td>
<td>7</td>
</tr>
<tr>
<td>2.4. Gel Treatments for Heterogeneous Formation without Crossflow</td>
<td>12</td>
</tr>
<tr>
<td>2.5. Gel Compositions (Sydansk et al., 2000)</td>
<td>13</td>
</tr>
<tr>
<td>2.6. Schematic of a Fractured Core (Seright et al., 1999)</td>
<td>19</td>
</tr>
<tr>
<td>2.7. Schematic of Sandpack Model (Bai et al., 2007)</td>
<td>20</td>
</tr>
<tr>
<td>2.8. Movement of Gel Particle through One Throat (Bai et al., 2007)</td>
<td>20</td>
</tr>
<tr>
<td>2.9. Screen Model (Challa, R., 2010)</td>
<td>20</td>
</tr>
<tr>
<td>2.10. Transparent Open Fracture Model (Zhang &amp; Bai, 2010)</td>
<td>21</td>
</tr>
<tr>
<td>2.11. Filtration Test and Load Pressure Model (Elsharafi and Bai (2012))</td>
<td>21</td>
</tr>
<tr>
<td>3.1. Homogeneous Model Setup</td>
<td>25</td>
</tr>
<tr>
<td>3.2. PPG swelling ratio in different brine concentration</td>
<td>27</td>
</tr>
<tr>
<td>3.3. Gel Strength measurement for different brine concentration</td>
<td>28</td>
</tr>
<tr>
<td>3.4. Injection Pressure changes with Injection Flowrate for ~ 4 mD cores</td>
<td>29</td>
</tr>
<tr>
<td>3.5. Injection Pressure changes with Injection Flowrate for ~ 26 mD cores</td>
<td>29</td>
</tr>
<tr>
<td>3.6. Injection stable pressure and Permeability reduction for the ~4 mD core</td>
<td>30</td>
</tr>
<tr>
<td>3.7. Injection stable pressure and Permeability reduction for the ~26 mD cores</td>
<td>31</td>
</tr>
<tr>
<td>3.8. Permeability of ~4 mD cores before and after PPG Treatment</td>
<td>32</td>
</tr>
<tr>
<td>3.9. Permeability of ~26 mD cores before and after PPG Treatment</td>
<td>32</td>
</tr>
<tr>
<td>4.1. Parallel Heterogeneity Model Setup</td>
<td>35</td>
</tr>
<tr>
<td>4.2. Injection pressure changes with injection flowrate for the low K</td>
<td>40</td>
</tr>
<tr>
<td>4.3. Injection pressure changes with injection flowrate for the low K</td>
<td>40</td>
</tr>
<tr>
<td>4.4. Injection Pressure changes with Cumulative Time for the sandpacks</td>
<td>41</td>
</tr>
<tr>
<td>4.5. Injection Profile changes with Cumulative Time for the sandpacks</td>
<td>42</td>
</tr>
<tr>
<td>4.6. Oil recovery changes with cum. fluid injected for the high K sandpack</td>
<td>44</td>
</tr>
<tr>
<td>4.7. Oil recovery changes with cum. fluid injected for the low K sandpack</td>
<td>45</td>
</tr>
<tr>
<td>4.8. Total Oil Recovery</td>
<td>45</td>
</tr>
</tbody>
</table>
4.9. Total Water Cut ................................................................................................................. 46
4.10. Injection pressure changes with injection flowrate for the high K sandpack ............. 48
4.11. Injection pressure changes with injection flowrate for the low K sandpack ............. 48
4.12. Injection pressure changes with cumulative time for the sandpacks ......................... 49
4.13. Injection Profile changes with cumulative time for the sandpacks ............................ 49
4.14. Oil recovery factor changes with cum. PV injected for the high K sandpack.......... 51
4.15. Oil recovery factor changes with cum. PV injected for the low K sandpack .......... 51
4.16. Total oil recovery factor for the permeability contrast of 20 .................................. 52
4.17. Water cut changes with cumulative fluid injected for the sandpacks .................... 52
4.18. Injection pressure changes with injection flowrate for the high K sandpack ......... 53
4.19. Injection pressure changes with injection flowrate for the low K sandpack .......... 54
4.20. Injection pressure changes with cumulative time for the sandpacks ....................... 54
4.21. Injection Profile changes with cumulative time for the sandpacks ....................... 55
4.22. Oil recovery factor changes with cum. PV injected for the high K sandpack .......... 56
4.23. Oil recovery factor changes with cum. PV injected for the low K sandpack .......... 57
4.24. Total oil recovery factor for the permeability contrast of 4 ................................. 57
4.25. Water cut changes with cumulative PV injected for the sandpacks ....................... 58
4.26. The effect of Permeability Contrast on Low K Oil Recovery ..................................... 59
4.27. The Effect of Permeability Contrast on High K Oil Recovery ............................... 60
4.28. The Effect of Permeability Contrast on Total Oil Recovery ................................. 60
# LIST OF TABLES

<table>
<thead>
<tr>
<th>Table</th>
<th>Page</th>
</tr>
</thead>
<tbody>
<tr>
<td>2.1. Current Performed Gel Systems</td>
<td>15</td>
</tr>
<tr>
<td>3.1 Typical characteristics of LiquiBlock™ 40K PPG</td>
<td>23</td>
</tr>
<tr>
<td>3.2. Summary of Permeability Reduction Results</td>
<td>32</td>
</tr>
<tr>
<td>4.1. The Sandpack Properties for Permeability Contrast of 44</td>
<td>39</td>
</tr>
<tr>
<td>4.2. Fluid Distribution showing the split of flow between low and high K sandpack</td>
<td>43</td>
</tr>
<tr>
<td>4.3. The Sandpack Properties for Permeability Contrast of 20</td>
<td>47</td>
</tr>
<tr>
<td>4.4. Fluid Distribution showing the split of flow between low and high K</td>
<td>50</td>
</tr>
<tr>
<td>4.5. The Sandpack Properties for Permeability Contrast of 4</td>
<td>53</td>
</tr>
<tr>
<td>4.6. Fluid Distribution showing the split of flow between low and high sandpack</td>
<td>55</td>
</tr>
<tr>
<td>4.7. The Incremental Oil Recovery Results</td>
<td>59</td>
</tr>
<tr>
<td>4.8. Comparison of Fluid Distribution and Oil Recovery Results</td>
<td>61</td>
</tr>
</tbody>
</table>
## NOMENCLATURE

<table>
<thead>
<tr>
<th>Symbol</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>A</td>
<td>Cross-sectional Area (cm$^2$)</td>
</tr>
<tr>
<td>FW</td>
<td>Water Cut (%)</td>
</tr>
<tr>
<td>K</td>
<td>Absolute Permeability (mD)</td>
</tr>
<tr>
<td>$K_A$</td>
<td>Core permeability after injecting PPG (mD)</td>
</tr>
<tr>
<td>$K_I$</td>
<td>Initial Core Permeability (mD)</td>
</tr>
<tr>
<td>$K_{RD}$</td>
<td>Core Permeability Reduction (%)</td>
</tr>
<tr>
<td>L</td>
<td>Length of core (cm)</td>
</tr>
<tr>
<td>q</td>
<td>Flowrate (ml/sec)</td>
</tr>
<tr>
<td>OOIP</td>
<td>Original oil in place (cc)</td>
</tr>
<tr>
<td>RF</td>
<td>Oil Recovery Factor (%)</td>
</tr>
<tr>
<td>$S_{oi}$</td>
<td>Initial Oil Saturation (cc)</td>
</tr>
<tr>
<td>SR</td>
<td>Swelling Ratio (cc)</td>
</tr>
<tr>
<td>$S_{WI}$</td>
<td>Irreducible Water Saturation (%)</td>
</tr>
<tr>
<td>$S_W$</td>
<td>Water Saturation (cc)</td>
</tr>
<tr>
<td>$V_1$</td>
<td>Initial Volume of PPG before swelling (cc)</td>
</tr>
<tr>
<td>$V_2$</td>
<td>Final Volume of PPG after swelling (cc)</td>
</tr>
<tr>
<td>$V_H$</td>
<td>Vol. of fluid injected to the high K sandpack</td>
</tr>
<tr>
<td>$V_L$</td>
<td>Vol. of fluid injected to the low K sandpack</td>
</tr>
<tr>
<td>$V_B$</td>
<td>Bulk Volume (cc)</td>
</tr>
<tr>
<td>$V_P$</td>
<td>Pore Volume (cc)</td>
</tr>
<tr>
<td>$V_T$</td>
<td>Total volume of Liquids produced from sandpack (cc)</td>
</tr>
<tr>
<td>$V_{WP}$</td>
<td>Volume of water produced from sandpack (cc)</td>
</tr>
<tr>
<td>$W_D$</td>
<td>Dry Weight of sandpack tube (g)</td>
</tr>
<tr>
<td>$W_S$</td>
<td>Saturated Weight of sandpack tube (g)</td>
</tr>
<tr>
<td>$\mu$</td>
<td>Viscosity (cp)</td>
</tr>
<tr>
<td>$\Delta p$</td>
<td>Pressure drop across the core (atm)</td>
</tr>
</tbody>
</table>
1. INTRODUCTION

The oil industry has estimated that billions of dollars will be spent over the next
decade to handle increased water production and water disposal regulations has become
more unbearable. In addition, excess water increases costs related to scale, corrosion,
water/oil separation, and, eventually, well shut-in. These costs climb as water production
increases (Dalrymple, 1997). Thus, it is not surprising that controlling the excessive
water production commonly known as conformance have become important to the oil and
gas operators.

Excess water production has become a major problem of oilfield operations as
reservoirs mature (Bai, 2008, Seright, 2003). Excess water production makes a well
unproductive and economically inefficient, leading to both an abandonment of early wells
and a reduction in hydrocarbon production. Much of this excess produced water was
injected during secondary recovery processes. This injected water tends to pass through
highly permeable, low resistance channels and fractures leading to poor oil sweep
efficiency of the adjacent low permeability zones. This poor oil sweep efficiency is as a
result of the heterogeneity of the reservoirs.

Reservoir heterogeneity is the single most important reason for low oil recovery
and excess water production. Most oilfields are characterized by complex geological
conditions and high permeability contrast inside reservoirs. Many of them have been
hydraulically-fractured, intentionally or unintentionally, or have been channeled due to
mineral dissolution and production during waterflooding (Liu, 2006). Reservoirs with
induced fractures or high permeability channels are quite common in the matured
oilfields. To mitigate this problems, gels have been introduced as a plugging agent to
plug fractures and thus restricts water from flowing through this high permeability
fractures and direct flow to the low permeability zones.

Gel treatment is one of the most important methods to correct reservoir
heterogeneity. Gel treatments have been used extensively in field applications to both
improve oil recovery and reduce water production (Seright et al., 1994, 2003). Gel
treatments is a cost-effective method for oilfield conformance control. Traditionally,
in-situ gels formed by the reaction of polymer and crosslinker at reservoirs have been
used widely to control conformance. However, a newer trend in gel treatments uses preformed particle gel (PPGs) for this purpose because they are formed at surface facilities before injection and they overcome distinct drawbacks inherent in in-situ gelation systems. These drawbacks include the inability to control gelation time, the uncertainty of gelling due to shear degradation, gelant composition changes caused by chromatographic fractionation effect, and dilution by formation water (Chauveteau et al., 2003; Bai et al., 2007a, 2007b).

Previous literatures have demonstrated the transportation and plugging efficiency of PPGs in both fractures (Zhang et al., 2010), super high permeable formations (Bai et al., 2004 & 2007) and un-swept low permeability zones/area (Elsharafi and Bai, 2012) but no work have been reported to study the effect of PPG treatment in heterogeneous reservoirs using the parallel heterogeneity model with no crossflow.

This research present an extensive investigation of the effect of PPG on reservoirs with varying permeability contrast and is based on laboratory experiments of studying the swelling ratio of PPG, core permeability reduction, sandpacks oil recovery, injection profile, water cut and injection pressure.

1.1. OBJECTIVE OF THESIS

This research is a study of the conformance control treatment by the injection of PPG and is explored as one cost-effective method of handling reservoir heterogeneity, controlling water production in matured oil fields and recovering more oil from the un-swept low permeability zones.

The first part of this thesis investigates the mechanisms responsible for the permeability reduction of a homogeneous sandstone cores caused by the injection of PPG. The findings from the result of this first part can significantly assist in optimizing the design of PPG treatments.

The objectives of the second part of this thesis is to evaluate the effect of PPG in improving the oil sweep efficiency of low permeability zone using different permeability contrasts of parallel heterogeneity sandpack model without crossflow. The results of this study was completed by monitoring the oil recovery, injection profile and water cut and injection pressure before, during and after PPG injection.
2. LITERATURE REVIEW

2.1. INTRODUCTION TO ENHANCED OIL RECOVERY

Enhanced Oil Recovery (EOR) involves injection of materials not normally present in reservoir. The injected fluids and injection process supplements the natural energy present in the reservoir to displace oil to a production wells. The injected fluids interact with the reservoir rock/oil system to create conditions favorable for oil recovery. Enhanced oil recovery (EOR), also known as tertiary recovery, is a process used to extract remaining oil left in a reservoir after water flooding (Roger et al., 2003). Enhanced oil recovery methods have been shown to work in many reservoirs worldwide where a large portion of the original oil in place (OOIP) remains (Adams et al., 1987; Chang et al. 2006; Jayanti et al. 2007). The potential for EOR worldwide therefore is very high. In recent years, numerous advancements have made these technologies not only more practical but also economically feasible.

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.

There are three mechanisms of oil production as shown in Figure 2.1 which includes: primary, secondary, and enhanced oil recovery. Primary recovery is the first mechanism of hydrocarbon production using natural energy to push oil out of the reservoir. Primary recovery includes: gas cap drive, solution gas drive, natural water drive, and gravity drainage. Unfortunately, this stage extracts only 12 to 15% of the oil within the reservoir. Secondary recovery begins with applied pressure maintenance upon exhaustion of natural energy. Water and natural gas injection are the two most common methods of secondary recovery. In each case, water or natural gas is pumped into reservoir to maintain reservoir pressure and displace the oil into the wellbore. This
increases the recovery factor to 35-40% on average typically leaving more than 60% of the oil still in the reservoir. When the reservoir produces a large amount of injection fluid, the production is no longer economical. Enhanced oil recovery becomes necessary to return production to an economically viable level. It can be applied following secondary recovery or directly after primary recovery.

Figure 2.1. Three stages oil production (Green & Willhite, 1998)

2.2. EXCESS WATER PRODUCTION

Excess water production is a serious problem in oil-producing reservoirs. The American Petroleum Institute estimates that over 15 billion barrels of water are produced annually. This is about eight barrels of water produced for each barrel of oil (Environmental Protection Agency, 2000). Worldwide, averages of three barrels of water are produced for each barrel of oil (Bailey et al., 2000). This produced water is water brought up from the hydrocarbon bearing strata during extraction of oil or gas. It includes formation water, injection water, condensed water and trace amount of treatment chemicals.

Excess water production from a hydrocarbon reservoir is a major problem for operators in mature oil fields (Bai et al., 2008). These reservoirs usually have a high water cut of more than 80% (Wu et al., 2000). Higher levels of water production result in higher levels of corrosion and scales, an increased load on fluid handling facilities, more environmental concerns, and the shorter economic life of a well. Consequently, producing zones are often abandoned in an attempt to avoid water contact, even when the
intervals still retain large volumes of recoverable hydrocarbons (Dalrymple, 1997). The annual cost of disposing of this water is estimated to be 50 billion dollars per year (Hill et al., 2012).

2.3. CAUSES OF EXCESS WATER PRODUCTION

Many factors are responsible for the excess water production from oil fields. Reservoir heterogeneity is one major reason. Fractures or channels (either natural or artificially induced) are examples of heterogeneity existing in reservoirs. These fractures or channels often cause excess water production and reduced oil recovery efficiency. Reservoir heterogeneity severely affects the flow of gas, oil, and water in the reservoir. In addition, it influences the choice of production strategies, reservoir management, and, ultimately, oil recovery methods. Reservoir heterogeneity is the single most important reason for both low oil recovery and early excess water production (Bai et al., 2007).

Excess water production can further be categorized into reservoir related problems and wellbore problems.

2.3.1. Reservoir Related Problems. Reservoir-related problems includes: coning, channeling through high permeability streaks, fingering, fractures, fracture communication, poor areal sweep, moving oil-water contact, and gravity segregated layer. Figure 2.2 illustrates the reservoir sources of unwanted water production. It shows the reservoir related problems of:

a) Fractures or faults from watered layer (Bailey et al., 2000)
b) Fractures or faults between injectors and producers (Bailey et al., 2000)
c) Water Coning
d) Channeling through matrix with crossflow (Seright et al., 2003),
e) Poor areal sweep (Bailey et al., 2000)
f) Moving water-oil contact (Bailey et al., 2000)
g) Gravity-segregated layer (Bailey et al., 2000).

To maintain reservoir pressure, these reservoirs have typically been developed by water flooding from the early stage of their development. Many reservoirs have either been hydraulically fractured (either intentionally or unintentionally), or channeled due to mineral dissolution and/or sand production during waterflooding (Liu et al., 2010).
2.3.2. **Wellbore Problems.** Wellbore problems includes: casing leaks, both tubing and packer leaks, channels behind pipes, barrier breakdowns, and completions either into or near water. Figure 2.3 illustrates the sources of unwanted water production near wellbore. It shows the wellbore sources of:

a) Casing, tubing or packer leak (Bailey et al., 2000)
b) Un-fractured well with effective barriers to cross-flow (Bailey et al., 2000)
c) Flow behind casing (Bailey et al., 2000).
2.4. METHODS TO REDUCE EXCESS WATER PRODUCTION

Four key issues needs to be resolved before selecting methods to reduce excess water production: residual oil, high oil viscosity, heterogeneity, fracture and oil wet rock. The first factor is residual oil left in pore’s media and the second is high oil viscosity. Fingering of injected fluid through oil results from an oil viscosity being higher than the viscosity of the displacing fluid. The third issue is heterogeneity. Injected water prefers to flow through high permeability zones instead of flowing through a matrix system in heterogeneity reservoir. This phenomenon will create fingering problems and water channel problems. The fourth issue is fracture problems and oil wet rock. Many reservoirs are naturally fractured reservoirs, especially carbonate reservoirs. Plenty of channels occur in carbonate reservoirs that will decrease sweep efficiency and oil wet rock will lead to more residual oil left in reservoir.
Methods to reduce excess water production can be classified into two main groups: 1) Mechanical methods and 2) Chemical Methods.

2.4.1. Mechanical Methods. Various mechanical methods have been used by operators to block water from entering into wells. The mechanical methods for shutting off water are restricted to either the application of specific completion tools as dual systems to avoid water coning (Seright et al., 2008; Wojtanowicz et al., 1999; Shirman & Wojtanowicz., 2000; Qin et al., 2009) or the use of hydro-cyclones to separate water from oil while the water is being produced (Veil et al., 1999; Veil et al., 2000). Mechanical methods are known to be the most suitable for wellbore related problems.

Seright et al., 2000 offer several mechanical methods which includes bridge plugs, wellbore sand plugs, straddle packers, tubing patches, infill drilling, pattern flow control and horizontal wells. Seright recommended that mechanical techniques to be used to block casing leaks, flow behind the pipe without flow restrictions and un-fractured well with barriers to cross-flow. However, these techniques may not be effective in solving other causes of excess water production problems.

2.4.2. Chemical Methods. Chemical method shut off water production by injecting chemicals near or deep in the formation either into the production or injection wells where they are unlikely to affect the underground water while allowing continued oil production. Chemicals for reducing excess water production include chemical plugging agents such as gels (in-situ gels, preformed particle gel), resins, foams, inorganic particle/particulate and precipitate.

Chemical methods include polymer flooding, micellar-polymer flooding, alkaline flooding surfactant flooding and gel treatment. In alkaline flooding, in-situ surfactants are formed when alkaline chemicals and petroleum acids reacted, which helps to loosen the oil from the rock by reducing interfacial tension and changing the rock surface wettability (Green & Willhite, 1998). Polymer flooding is the most important of the mature chemical treatment methods. Large-scale of polymer flooding projects are still underway each year. Most polymer solution with time evolves from viscosity liquids to either strong or weak gels depending on the solution’s formations. These polymer gels are used to shut off high permeability zones through which water is being produced. Other than regular polymer gel, new polymer based gels such as Colloidal Dispersion Gels and Bright Water
are currently been tested and evaluated. They are used to improve conformance problems by improving sweep efficiency.

Among these gel systems using both polyacrylamides and different crosslinkers have been the most extensively applied (Vega et al., 2010). These crosslinkers can be classified as either inorganic or organic (Al-Muntasheri et al., 2006). The inorganic crosslinking agents most widely used are based on Cr$^{3+}$, Al$^{3+}$, and Zr$^{4+}$. These agents are used with partially hydrolyzed polyacrilamides (PHPA). These crosslinkers generate ionic bonds with the carboxilate (negatively charged) groups in polymer. Organic crosslinkers are more stable at high temperatures due to the covalent bonds generated with the polyacrylamide (PAM) amides groups (Al-Muntasheri et al., 2007).

2.5. GEL TREATMENT

Gel treatments acting as a plugging agent is the most cost effective means to reduce water production and correct reservoir homogeneity in mature oil fields (Seright & Liang, 1994; Liang et al., 1992). These gels have been used extensively in field applications to both suppress excess water production and improve oil productivity (Seright et al., 2003). When gel treatment has been injected into formation, it can divert fluid flow from water channels to formation matrix. Fluid prefers to flow from high permeability and low oil saturation zone and will normally bypass low permeability zones with high oil saturation. Gel treatment can change this behavior, enhance oil production and improve flood sweep efficiency. Gel treatment can reduce production operation cost by lowering water production rate. In an oil field, gel treatment can be applied to conformance related problems such as water or gas shutoff treatment, sweep improvement treatment, squeeze and recompletion treatments or aged wells abandonment treatment.

Field experience has demonstrated that the selection of candidate wells is critical for the success of gel treatments (Seright et al., 2003). Since 1996, Preformed Particle Gels (PPGs) have been successfully synthesized and applied to control excess water production in some mature water-flooded oilfields in China (Bai et al., 2007). Gel particles vary in diameter from nanometers to a few millimeters. Selecting both the right particle size and strength is important for the success of gel treatment. It is also important
to understand the behavior of the gel in the porous media as it flows through both the fractures and channels of the high-permeability zone. Previous research on PPGs has focused on swelling rate, swelling gel strength, and flow resistance (Kabiri et al., 2003). Preformed bulk gels (Seright et al., 2004) and partially preformed gels (Sydansk et al., 2005) were studied for gel treatments in labs.

The size of the particle gels’ microspheres can be adjusted based on the pore throats of the treated zones. These microspheres have several characteristics that make them ideal for field use, including salt acceptance, ease of injection, elastic properties, and the ability to deeply penetrate sandstone cores. Particles that allow them to change shape, thus flowing deeper into the reservoir. As a result, more oil can be swept. Several processes have been proposed to reduce the channeling of fluids through both fractures and streaks of very high permeability in reservoirs. Processes that use either crosslinked polymers or other types of gels have been most common. This analysis focused on both the placement characteristics and the permeability-reduction properties of PPGs.

Both fractures and channels in porous media are, primarily, responsible for decreasing productivity because large volumes of injection water enter the channels and fractures. PPGs could solve this problem by plugging both.

Laura et al. (2004) studied the characterization of crosslinked gel kinetics and gel strength using nuclear magnetic resonance (NMR). They used both rheological and qualitative methods to determine both gel strength and gelation rates. They reported that low-field NMR can be a useful tool for monitoring the gelation process of polyacrylamide/chromium (III) acetate (Laura et al., 2004).

Kuzmichonok et al. (2007) studied the use of various gel systems to reduce the production of unwanted water and thus improve oil recovery. The main objective of their study was to evaluate gel performance during the simultaneous injection of brine and oil. They investigated the effect of residual oil saturation (Sor) on gel behavior by conducting experiments both with and without the presence of Sor prior to gel placement. They also studied Alcoflood-935-chromium (III)-chloride (AF-935-Cr (III)-Cl) gel in crushed carbonate rock.
Jia et al. (2011) used polymer gel to mitigate the filtration of gelant (both a fluid solution of cross-linker and a polymer that exists before gelation). They used both resorcinol and phenol-formaldehyde as the first and secondary cross-linkers. They found that the resorcinol can quickly cross-link with HPAM at room temperature. Gelant, formulated with a combination of 0.3 wt. % HPAM and added to 10-30 mg/L resorcinol, can increase its viscosity from 10.2 to 150 mPas within 2 hours.

Kim et al. (2003) addressed both the effect of gel composition on swelling and the mechanical properties of particle gels. Kim et al. (2003) created poly (acrylamide-co-acrylic acid) (poly (AM-co-AA)) superporous hydrogels (SPHs). Additionally, they studied the acidification effects on both the swelling and the mechanical properties on those gels. They measured gelation to determine the optimal time for introduction of a blowing agent. They noticed that gelation kinetics decreased as the concentration of AA. Poly (AM-co-AA) increased.

Reservoirs with induced fractures or high-permeability channels are quite common in mature oilfields (Bai et al., 2008; Liu et al., 2010). Gel treatment is one of the most important methods for correcting reservoir heterogeneity (Almuntasheri & Zitha, 2009; Thomas et al., 2000; Wang et al., 2008; Bai et al., 2007; Zitha & Darwish, 1999; Wu & Bai, 2008 & 2011).

Gels have, traditionally, been placed near either the wellbore of production or the injection wells to correct interlayer heterogeneity, or fractures, as illustrated in Figure 2.4. However, the oil remaining on top of a thick heterogeneous layer is the most important target of oil recovery efforts as a reservoir matures.

If no crossflow between low-permeability and high-permeability zones exists, a small amount of gel can be injected near the wellbore. A gel placed in the high-permeability zone near the injection wellbore will reduce the permeability of that zone. Thus, more water will penetrate into the low-permeability zone. Therefore, the injection profile must be controlled. On the contrary, a gel placed near the production wellbore will reduce the permeability of the high-permeability zone so that more oil can be produced from the low-permeability zone.
2.6. CONFORMANCE CONTROL

Conformance is the measure of the volumetric sweep efficiency during an oil-recovery flood process being conducted in an oil reservoir. Conformance control is a broader technology set in that it tries to address reservoir heterogeneity. This technique encourages the drive mechanism to mobilize rather than avoid those hard-to-move pockets of un-swept oil and gas. The goal of conformance is to correct reservoir heterogeneity and improving the sweep efficiency. Conformance control treatments are usually more economical than other EOR techniques; they can both increase oil production and decrease water production by treating only small swept zones/areas (Borling et al. 1994).

2.6.1. Gels used for Conformance Control Treatment. Two types of gels for conformance control are currently used in the oil industry:

2.6.1.1 In-situ gels systems. The first application of an in-situ gel for the conformance control of oil reservoirs was applied in 1970 (Mack et al., 1978). Traditionally, in-situ gels have been widely used to control conformance especially for in-depth fluid diversion (Liu et al., 2010). In-situ gels are crosslinked polymers composed of several chemical materials, including polymer, crosslinker, and additives. The liquid formulation of this composition is called a gelant. In an in-situ system, the
gelant is injected into the formation, and the gel forms under reservoir conditions (Liu et al., 2010). Their crosslinking reactions, however, are strongly affected by degradation caused by the pump, the wellbore and porous media, adsorption and chromatography of chemical compositions and dilution of formation water. Under conditions such as either increasing temperature or changing pH, the gelant can crosslink to form a gel. Gel strength can be controlled by both gelant composition and surrounding conditions; it can be very weak, like a flowing gel, or very rigid, like rubber, as displayed in Figure 2.5.

![Gelant to Gel Transformation](image)

Figure 2.5. Gel Compositions (Sydansk et al., 2000)

The Colloidal dispersion gels (CDG) which is a type of in-situ gel systems are prepared by crosslinking a low concentration of polymer solutions with a small amount of either chromium acetate or aluminum citrate (Chang et al., 2004 and Al-Assi et al., 2009). Spildo et al. (2009) investigated the applicability of CDG at higher salinity (35,000 ppm) sandstone reservoirs. Positive results were reported through a one week reaction time was needed to complete the crosslinking reaction.

Juntai et al. (2011) noted that CDG can be used for both conformance and mobility control. Different conclusions exist regarding whether or not CDG can propagate in the porous media. They studied two CDG types: 1) CDG that is performed before being injected into the porous media and 2) CDG that is formed in-situ under reservoir conditions. Preformed CDG is a stable microgel. Therefore, it is typically used for both conformance and mobility control. They developed a novel viscosity model for stable microgels. Their viscosity model is a function of the both microgel concentration
and the shear rate; it was confirmed by matching their results with published microgel data.

CDGs have a high injectivity due to a relatively low polymer concentration. Gelation is affected by both shear and reaction of chemicals with both reservoir rocks and fluids. Predicting CDGs gelation time and strength is difficult due to the both flowing and reservoir effect. CDGs easily penetrate and damage low permeability oil zones before gelling. Both their thermal and salt resistance depends on polymer properties.

Liu et al. (2010) noted that typical chemicals are weak gels, preformed particle gels (PPGs), and colloid dispersion gels (CDGs). Polymer concentrations (excluding crosslinker and other additives) usually range from 1,000 to 3,000 mg/l for weak gel and from 400 to 1000 mg/l for CDG. Polymer concentrations below 1000 mg/l cannot be used in reservoirs with either fractures or extremely high channels.

2.6.1.2 Preformed gel systems. For the preformed gel systems, gel is formed in surface facilities before injection and then gel is injected into reservoirs. No gelation occurs in reservoir. All particle gels used for conformance control are superabsorbent polymers (SAP).

Currently, commercially available preformed gel systems include preformed particle gels (PPGs) (Coste et al., 2000; Bai et al., 2004, 2007, and 2008), microgels (Chauveteau et al., 2000, and 2001; Rousseau et al., 2005; Zaitoun et al., 2007; Feng et al., 2003), pH-sensitive crosslinked polymers (Al-Anazi et al., 2001 & 2002; Huh, et al., 2005; Beson et al., 2007; Choi & Shrman, 2009), swelling micron-sized polymers (Bright Water®) (Pritchett et al., 2003; Frampton et al., 2004). Field applications of some gels have yielded positive results (Pritchett et al., 2003; Bai et al., 2007; Liu et al., 2010).

PPGs, microgels, and BrightWater have all been used to reduce water production in mature oilfields. Published documents indicate that several particle gels were economically applied to reduce water production in mature oilfields. For example, PPGs have been applied in approximately 5000 wells in China to reduce fluid channels in both water floods and polymer floods (Liu et al., 2010). Recently, Occidental Oil Company and Kinder-Morgan used a similar product to control the CO2 breakthrough for their CO2 flooding areas, and promising results have been achieved (Larkin & Creel 2008; Smith et al, 2006; Pyziak & Smith 2007). Table 2.1 lists both the different types of
preformed gel systems used in the oil industry, their developer, particle size and applications.

Table 2.1. Current Performed Gel Systems

<table>
<thead>
<tr>
<th>Name</th>
<th>Developer</th>
<th>Particle Size</th>
<th>Applications</th>
</tr>
</thead>
<tbody>
<tr>
<td>Bright Water®</td>
<td>Chevron, BP and Nalco (Tirco)</td>
<td>Sub-Micro (&lt; 1µm)</td>
<td>60+ Injectors</td>
</tr>
<tr>
<td>Microgel</td>
<td>IFP</td>
<td>Micro (1-10µm)</td>
<td>10+ Producers</td>
</tr>
<tr>
<td>PPG</td>
<td>PetroChina, MS&amp;T and Halliburton</td>
<td>Millimeter (10 µm to mm)</td>
<td>5000+ Injectors in China</td>
</tr>
<tr>
<td>pH Sensitive polymer</td>
<td>UT Austin</td>
<td>Micro</td>
<td>Not reported</td>
</tr>
</tbody>
</table>

- Brightwater®: Brightwater® was developed by industry group BP, Chevron and Nalco. It is now commercialized by Tiorco (Nalco Company). It was first tested in Indonesia in 2001 (Pritchett et al., 2003). A sub-microsized particle gel was developed by both Pritchett et al. (2003) and Frampton et al. (2004) for in-depth division conformance control treatments. Both BP and Chevron used Brightwater® for more than 60 injection wells without either super-high permeability or streaks. Their results determined that oil recovery increased after the injection of sub-micron particles into the sweep oil zones/areas (Pritchett et al., 2003; Frampton et al., 2004). Brightwater® is a sub-micron particulate injected downhole wells, with the injection water as a one-time batch (Roussennac et al., 2010). It can be deployed with conventional chemical injection equipment, requiring no modification to the existing water injection system (Roussennac et al., 2010). Particle sizes are sufficiently small enough (~0.5 micron) to propagate through the rock pores with the injected water (Roussennac et al., 2010). As the sub-micron particle (polymer) passes through the reservoir it gradually warms towards the reservoir, temperature. As it heats up, the polymer expands to many times its original volume (a factor of four to ten, depending on salinity), blocking pore throats, and diverting any water following behind it (Roussennac et al., 2010).

The selections of the right sub-micron particles are available, depending on the thief zone properties, water salinity, and reservoir temperature. A number of treatments were performed in Alaska (Danielle et al., 2009), the North Sea (Nancy et al., 2010), and Argentina (Pablo et al., 2007). Later treatments in Argentina gave no indication of
increased recovery. Alaska treatments quoted a four-year gain of 60,000 barrels against a ten-year target of 50,000 to 250,000 barrel, at less than 5 USD for each barrel (Rousssennac et al., 2010). A North Sea application claimed over 130,000 barrel of oil increase in the first 12 months at 4 USD for each barrel (Rousssennac et al., 2010). Its final incremental recovery estimated to rise up to 300,000 barrel (Rousssennac et al., 2010).

- Microgels: Chauveteau et al. (2001, 2003, and 2004) developed a microgel system for water control. The microgels are colloidal particles of acrylamide based crosslinked with zirconium. The size of microgels (polymer aggregate) can be changed during shearing. However, the properties of microgels are affected by salinity, pH, and shear rate.

  The resistance of microgels is weak (Chauveteau et al., 2001, 2003, and 2004). Chauveteau et al. (2004) obtained with a new type of microgel. The results include both their characteristics in solution (size, intrinsic viscosity, mutual interactions, and rheology) as well as their performances in a porous media (both model granular packs and Berea sandstones). These microgels were found to reduce water permeability strongly by forming thick adsorbing layers. They found that oil permeability is not affected by microgels (Chauveteau et al., 2004). Both mechanical and thermal stability of microgels is excellent. Their shear rates can be as high as 1.5×10^4 s^{-1}. Their viscosity did not change for a month at 150°C. Microgels penetrate completely into super-high permeability layers and reduced their permeability (Chauveteau et al., 2004).

  Chauveteau et al. (2000) described the primary results of both their theoretical and experimental investigations of microgels. Their study was focused on how to control both the size and the conformation of microgels formed under constant shear flow (Chauveteau et al., 2000). They found that microgels formed in the propagation area are isotropic. Their size decreases considerably as the shear rate increases. Juntila et al. (2011) presented an application of both microgel transport and retention in a 3-D chemical flooding simulator model. The efficiency of various microgels was tested using the reservoir simulator with the microgel transport and retention model. Juntila et al. (2011) developed a mechanical microgel-trapping model used reservoir rocks. They
found that the microgels did not penetrate into some of smaller pores. Microgels either adsorbed on the surface of larger pores or trapped at the throats of larger pores.

Burcik et al. (1967, 1968) studied the mechanism of microgels in the formation zones. They remarked that the reduction of water mobility by microgel solutions occurred from increasing microgel viscosity and decreasing water effective permeability. They reported that oil displacement on mature reservoirs could be improved by increasing both the microgel viscosity and the injection flow rate. In addition, they found that the polymer retained inside the pore channels caused pseudo flow at high shear rates.

- Preformed particle gels (PPGs): PPG is a dried superabsorbent cross-linked polymer powders that can absorb over few hundred times their weight in liquids (Bai et al., 2008). They have been applied successfully to control conformance in mature oil fields around the world. In PPG systems, the gel forms in surface facilities before injection into reservoirs; no gelation occurs in the reservoir.

  PPG particle size is adjustable from a scale of micrometers to millimeters. Particles have a swelling ratio between 10 and 200 times the original volume. This volume is controllable by adjusting the concentration of the brine solution. The particle’s resistance to salt permits the use of all salt types and concentrations. These particles are resistant to temperatures up to 110 °C and remain stable for more than a year below 110 °C. The primary component of PPGs is the potassium salt of a crosslinked polyacrylic acid/polyacrylamide copolymer.

  Bai et al. (2007) investigated the effect of gel compositions and reservoir environments on two properties of PPGs: swollen gel strength and swelling capacity. They reported that PPG properties are influenced by gelant composition, temperature, brine salinity, and a pH level below 6. Reservoir temperature increases PPG swelling capacity and decreases its swollen gel strength. Salinity decreases PPG swelling capacity and increases its swollen gel strength.

  Bai et al. (2007) successfully synthesized a new PPG product, testing the mechanism of PPG transport through porous media. They used etched-glass micromodels to visually monitor the path of gel particles, demonstrating that PPG propagation exhibits six patterns of behavior: direct pass, adsorption and retention, deform and pass, snap-off and pass, shrink and pass, and trap.
PPGs reduce water flow by plugging the high-permeability formation without damaging the production zone. PPGs improve both oil productivity and water injectivity. They both improve the macroscopic sweep efficiency and satisfy environmental regulations. Additionally, PPGs require less equipment for surface preparation. The concentration of polymer in the PPG is typically between 1000 and 5000 mg/l (Liu et al., 2010). In addition, they do not easily release the absorbed fluids under pressure (Bai et al., 2008). PPGs can absorb a large amount of water due to a hydrogen bond with a water molecule.

PPGs are developed in PetroChina, MS&T and Halliburton. They are applied in more than 5000 injection wells in China.

- pH-sensitive polymers: pH-sensitive polymers have been used to solve potential problems caused by polymer flooding, such as high injection pressure with associated pumping costs, the creation of unwanted injection well fractures, and the mechanical degradation of polymers due to high shear near the wellbore. pH sensitive polymers are currently developed in University of Texas at Austin and there have been no known reported applications.

2.7. GELS PROPAGATION THROUGH POROUS MEDIA

The selection of an appropriate gel and the design of an optimal treatment process depend on an understanding of gel behavior as it passes through high-permeability, fractures, and channels.

Seright et al. (1999) studied both the propagation and the dehydration of a preformed bulk gel through open fractures. Berea sandstone cores were used, fractured along the length of the core, and cast in epoxy, as illustrated in Figure 2.6. Both the height and the width of the cores were 3.81 cm. The height of the fracture was 3.81 cm. Both various internal taps and a gauge were attached to each to measure pressures along the fracture. These results can be used to identify the best gels for various fractures widths.
Coste et al. (2000) carried out a laboratory experiment to study if particle gel suspension can reduce the residual oil saturation of both homogeneous core and parallel cores. They found out that particle gel improve the oil recovery of homogeneous core by 10% while particle gel improve the oil recovery of the parallel cores by 20%. They further stated from their experience the particle gel presents a strong potential as self-selective system for water control applications.

Al-Anazi et al. (2002) studied the propagation of a pH-sensitive polymer solution through Berea cores, finding the solution penetrated easily through 6 inch cores. They found that the pH-sensitive polymer reduced the permeability of the cores. The permeability reduction occurred because the pH-sensitive polymer formed a rigid gel inside the pores after both shut-in period for 24 hours and increased pH value above 6.

Rousseau et al. (2005) determined that microgels have outstanding mechanical, chemical, and thermal stability as they propagate through porous media. There work used models of packed silicon carbide (SiC) particles and sandstone cores to evaluate both the in-depth propagation and the adsorption of their microgels.

Frampton et al. (2004) found that Bright Water® could be injected into either packs or cores with a permeability between 124 to 3400 mD. In addition, Bright Water® can reduce the permeability of the cores.

Bai et al. (2007) conducted core flooding tests using a sandpack core, as illustrated in Figure 2.7 to understand PPG transport through high-permeability porous media. Three types of flow patterns were identified: pass, broken and pass, and plug as shown in Figure 2.9. They also observed the particle performance of PPG in the porous media through visual micromodels. They found that PPG propagation shows six patterns of behavior: direct pass, adsorption, deform and pass, snap-off and pass, shrink and pass, and trap.
Challa, R. (2010) used a screen model comprised of a long acrylic tube, connected to an Isco pump (displayed in Figure 2.9), to study the flow behavior of PPG through screens. A piston was inserted into the acrylic tube. Screens of various mesh placed at the bottom of the tube represented permeable formations. Pressure from the pumped brine pushed the piston, forcing the PPG to pass through the screen. He found that the particles were permanently deformed after passing through the screen.
Zhang and Bai (2010) used the transparent fracture model, shown in Figure 2.10, both to understand PPG propagation through open fractures and to study water flow through the PPG-placed fractures. This model constitutes two parallel acrylic plates with a rubber O-ring between them. Bolts, nuts, and shims were used to fix the two plates and control the fracture width. This model allowed Zhang and Bai (2010) to study the effect of particle strength and size on gel injectivity as well as to observe particle movement in a fracture. They found that PPG can significantly reduce the permeability of fractures but cannot completely block fractures. Their research proposed the use of a gel pack, the permeability of which is affected by particle strength, particle size, and brine concentration.

Figure 2.10. Transparent Open Fracture Model (Zhang & Bai., 2010)

Elsharafi and Bai (2012) studied the effect of weak preformed particle gels (PPGs) on unswept, low-permeable zones/areas during conformance control treatments using filtration test model and load pressure model (Figure 2.11). They found out that PPG damage on rocks was affected by particle sizes and brine concentrations; more damage occurred with a small particle size (100-120 meshes) and a low brine concentration (0.05 wt. % NaCl).

Figure 2.11. Filtration Test and Load Pressure Model (Elsharafi and Bai (2012))
The previous works has evaluated the mechanistic behaviors of different gels in porous medium. This study will investigate extensively the permeability reduction caused by PPG treatment on a homogeneous reservoir as a function of brine concentration and core permeability and the effects of the permeability contrast in improving the oil recovery of the unswept low permeability to validate previous literatures.
3. EVALUATION OF PPG TREATMENT USING HOMOGENEOUS MODEL

3.1. INTRODUCTION

This chapter introduces an extensive evaluation of PPG properties and factors that will optimize the design of PPG treatment. It starts by evaluating the PPG swelling kinetics and gel strength as a function of concentration of brine. The findings from this evaluations will help understand the PPG plugging efficiency mechanism.

The results of PPG swelling ratio and gel strength lead to the investigation of the ability of PPG to reduce the permeability of high permeability zone. A homogeneous coreflooding model was designed to evaluate the effect of the PPG on this model. The injection stable pressures and permeability of these model was closely monitored before and after PPG treatment.

3.2. EXPERIMENT MATERIALS

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

3.2.1. Preformed Particle Gel (PPG). The PPG used in this study is commercially one known as LiquiBlock™40K. Its main chemical component is potassium salt of crosslinked polyacrylic acid/polyacrylamide copolymer. Dry PPG with a mesh size of 30 was selected. Table 3.1 below shows the properties of the PPG used.

<table>
<thead>
<tr>
<th>Properties</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Absorption Deionized Water (g/g)</td>
<td>&gt;200</td>
</tr>
<tr>
<td>Apparent Bulk Density (g/l)</td>
<td>540</td>
</tr>
<tr>
<td>Moisture Content (%)</td>
<td>5</td>
</tr>
<tr>
<td>pH Value</td>
<td>(+/- 0.5; 1% gel in 0.9% NaCl)</td>
</tr>
</tbody>
</table>
3.2.1.1 Preparation of swollen PPG sample. The swollen PPG used in these experiments was prepared as follows:

- An empty test tubes were filled with a brine solution of the desired concentration to prepare the PPG.
- Depending on the concentration of the brine, (which was used to prepare the PPG) grams of PPGs were weighed and slowly added to the brine solution.
- The sample was allowed to swell completely, a process that required more than 3 hours.
- The excess brine solution was separated from the swollen PPG using a screen.
- The PPG was collected from the screen and stored.
- PPG full swollen weight was measured after extra water was removed.

3.2.2. Brine. Sodium chloride (NaCl) was used in this experiment. Four brine concentrations (0.05%, 0.25%, 1%, 10wt. %) 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.

3.2.3. Berea Sandstone Core. Berea sandstone cores with the permeability ranging from 3.5mD to 25.5mD having a diameter of 2.5cm and length of 4.5cm was used for the experiments.

3.2.4. HAAKE™ RheoScope. Rheoscope was used to measure the storage modulus (G’) for the PPG swollen in brine. The sensor used for measurements is PP335 TiPoLO2 016 with a gap of 0.8 mm between the sensor and the plate. All gel strength measurements were performed at a room temperature of 25°C.

3.3. EXPERIMENTAL SETUP

Figure 3.1 represents the experiment setup, which was mainly composed of a syringe Isco-pump used to inject brine and PPG through the accumulator into a Hassler core holder. Berea sandstone was placed inside the holder, and the confining pressure was adjusted to have a minimum of 500 psi above the injection pressure. 5cm long
Spacers were placed inside the core holder in front of the core to allow PPG placement at the sand face of the core. An injection pressure gauge was installed at the inlet of the core holder to measure the brine injection pressure during the experiment. Test tubes were mounted at the effluent to collect the brine produced during the injection process.

![Figure 3.1. Homogeneous Model Setup](image)

### 3.4. EXPERIMENTAL PROCEDURE

The experiment procedure was divided into two main steps. The first step was to investigate the swelling ratio of PPG in different NaCl concentrations. The second step was to evaluate the effect of PPG as a function of water salinity and rock permeability using core-flooding experiments.

#### 3.4.1. PPG Swelling Ratio Procedures

0.5 ml of dry PPG with 30 mesh size was immersed in different beakers containing 49.5 ml of different brine concentrations (0.05%, 0.25%, 1%, and 10%) of NaCl at room temperature to determine the swelling ratio of PPG with time. The swelling ratios of PPG in different brine solutions were obtained using Equation 3.1 below.

\[
\text{Swelling Ratio (SR)} = \frac{V_2 - V_1}{V_1}
\]

Equation 3.1

where \( V_2 \) is the final volume of the PPG after swelling and \( V_1 \) is the initial volume of the PPG before swelling.
3.4.2. Core-flooding Experiment Procedures. The procedures used for the core flooding experiments were briefly described as follows:

1) The Berea sandstone with the desired rock permeability was placed in the oven at 110°C for 24hrs before it was vacuumed and then saturated with 1% NaCl.
2) The core was put in the Hassler core holder and was subjected to a confining pressure.
3) The average absolute permeability of the core using Darcy’s Law was measured using flow rates of 0.5, 0.75, 1, 1.25, 1.5, 1.75, 2 and 3ml/min.
4) A 60ml solution of completely swollen PPG in desired brine concentration (0.05%, 1%, 10 wt. %) was injected through a 5cm spacer and placed facing the core.
5) Brine with the same concentration was injected again using the same flow rates of 0.5, 0.75, 1.0, 1.25, 1.5, 1.75, 2.0 and 3.0ml per min.
6) PPG was removed from the core holder after brine injection and the permeability of the core was measured again to see the effect of the brine concentration on the core permeability reduction.
7) The above procedure was repeated for each experiment and stable injection pressures was plotted against the flow rates for the desired brine concentration and rock permeability.

3.5. RESULTS ANALYSIS AND DISCUSSION

3.5.1. Evaluation of PPG Swelling Ratio and Gel Strength. The dry PPG was placed separately in test tubes filled with different concentrations of brine. The stable swelling ratio was computed for each concentration.

Figure 3.2 shows the influence of the brine concentration on the swelling ratio. PPG showed normal swelling ratio behavior; its swelling ratio initially increased with time and then attained equilibrium. Swelling ratio for PPG swollen in brine could reach to 165 when it is swollen in 0.05% brine concentrations. The swelling ratio for PPG increases as the brine concentrations decreased. The swelling ratio increased by a factor of two (from 81 to 165) when the brine concentrations decreased from 0.25% to 0.05%. As the brine concentration decreased, the PPG swell more, becomes weaker, and begins
to soften. This decrease in strength is likely as a result of the PPG adsorbing a large amount of water and also presumably due to the static electric repulsive force and charge balance. 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).

The influence of concentration of brine on the PPG strength was investigated using a rheometer to measure the strength of the PPG swollen in 0.05%, 0.25%, 1% and 10% wt. NaCl. Gardner (1983) used rheometers to study the rheology of relatively weak gels and polymers. Sydansk (1990) proposed bottle-test gel strength to evaluate gel strength using letter codes. Figure 3.3 shows the measurement of the PPG storage modulus for gels swollen in different concentrations of brine. The result indicates that the PPG swollen in the higher brine concentrations was much stronger than the PPG swollen in the lower brine concentrations.
3.5.2. Evaluation of Permeability Reduction. PPG swollen in brine concentrations of 0.05%, 1%, and 10% was selected to evaluate the permeability reduction of the Berea sandstone cores.

Darcy’s law was applied to calculate the core permeability before and after PPG injection. The permeability can be obtained using Equation 3.2 below.

\[ K = \frac{q \mu L}{A \Delta P} \]  

where \( q \) is the flow rate (ml/sec), \( \mu \) is the brine viscosity (cp), \( L \) is the length of the core (cm), \( A \) is the cross-sectional area (cm\(^2\)), and \( \Delta p \) is the pressure drop across the core (atm).

Figure 3.4 below shows the injection pressure changes with injection flowrate using 1 wt. % NaCl to obtain the core absolute permeability of ~4 mD while Figure 3.5 below shows the injection pressure changes with injection flow rate tusing same 1 wt. % NaCl obtain the core absolute permeability of ~26 mD.
Permeability reduction, which is defined as the relationship between the initial permeability before PPG injection and the permeability after injection of PPG will be applied to evaluate the effect of PPG and can be calculated using Equation 3.3 below.

\[ K_{RD} = \left( \frac{K_i - K_a}{K_i} \right) \times 100 \]  

Equation 3.3

where \( K_{RD} \) is the core permeability reduction (%), \( k_i \) is the initial core permeability (mD), and \( k_a \) is the core permeability after injecting PPG (mD).
These permeability reductions caused as a result of PPG propagation through the homogeneous model will enable us determine the effects of swollen PPG prepared with different concentration of brine on the core permeability. The permeability of the sandstone cores were measured carefully after PPG was removed together with the spacers. Figure 3.6 (a) shows the injection stable pressure results obtained for the ~4 mD cores. The brine injection pressure increased as the salt concentrations decreased. The injection pressure increased approximately five times (from 50 to 250psi) as the salt concentrations decreased from 10 wt. % to 0.05 wt.%.

Also, the softness and deformability of the swollen PPG in the lower salt concentration enabled the PPG to invade a small amount into the pore throat. Figure 3.6 (b) illustrates the results obtained for these brine concentrations in terms of permeability reductions. The permeability reduction increased as the brine concentration decreased. Almost a 90 percent permeability reduction was observed when the gel was placed with the lower concentration of brine; however, only a 29.5 percent permeability reduction was observed for the highest concentration of brine. Results from these two figures suggest that PPG swollen in high brine concentration exhibited less ability to propagate into the core than PPG swollen in low brine concentration.

(a) Injection stable pressure
(b) Permeability reduction

Figure 3.6. Injection stable pressure and Permeability reduction for the ~4 mD core
Figure 3.7 (a) shows the injection stable pressure results obtained for the ~26 mD cores. The injection pressure increased significantly as the brine concentrations decreased. Higher injection pressure was noticed for this range of permeability compared to the permeability range in Figure 3.6 (a). This increase reveals that PPG can propagate into high core permeability more deeply than if it is placed into low core permeability. As a result, Figure 3.7 (b) shows that the decreased in core permeability is more significant in high permeability cores than in low permeability cores.

![Figure 3.7](image)

(a) Injection stable pressure  
(b) Permeability reduction

Figure 3.7. Injection stable pressure and Permeability reduction for the ~26 mD cores

Comparing the two different ranges of permeability, PPG swollen in 0.05% brine exhibits a significant permeability reduction as both ranges of permeability reached above 90%. When the permeability was increased to ~26 mD, the permeability reduction increased from 29.5% to 85% for the PPG swollen in the 10% brine. Consequently, brine injection pressure increased significantly. The injection stable pressure increased as the brine concentration decreased and increased more significantly as the permeability of the core increased.

These results suggest that PPG can propagate deeply into higher permeability rock due to the results of the high permeability reduction witnessed in this study.
Figure 3.8 below shows the effect of PPG treatment in reducing the permeability of the ~4 mD cores while Figure 3.9 shows the effect of PPG treatment in reducing the permeability of the ~26 mD cores for different brine concentration.

![Figure 3.8. Permeability of ~4 mD cores before and after PPG Treatment](image1)

![Figure 3.9. Permeability of ~26 mD cores before and after PPG Treatment](image2)

Table 3.2 below summarizes the results of permeability reduction. It illustrates the effects of brine concentration and core permeability as PPG propagates through these sandstone cores.

Table 3.2. Summary of Permeability Reduction Results

<table>
<thead>
<tr>
<th>Brine concentration (% wt. NaCl)</th>
<th>Absolute permeability before PPG Treatment (mD)</th>
<th>Permeability after PPG Treatment (mD)</th>
<th>Permeability Reduction (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>0.05</td>
<td>3.5</td>
<td>0.3</td>
<td>91.4</td>
</tr>
<tr>
<td>1</td>
<td>4.3</td>
<td>0.5</td>
<td>88.3</td>
</tr>
<tr>
<td>10</td>
<td>4.4</td>
<td>3.1</td>
<td>29.5</td>
</tr>
<tr>
<td>0.05</td>
<td>21.8</td>
<td>0.08</td>
<td>99.8</td>
</tr>
<tr>
<td>1</td>
<td>20.8</td>
<td>0.42</td>
<td>98</td>
</tr>
<tr>
<td>10</td>
<td>25.5</td>
<td>3.80</td>
<td>85.0</td>
</tr>
</tbody>
</table>
The results of PPG swelling kinetics and gel strength discussed in this chapter indicates that the 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, becomes deformable and weaker when prepared with low concentration of brine than when prepared with high concentration of brine.

The result of the homogeneous coreflooding model carried out on the Berea sandstone core indicates that PPG swollen with low concentration of brine caused more permeability reduction and can penetrate easily into the core than PPG swollen with high concentration of brine. Also, the permeability reduction of the core is more significant when higher core permeability was used.

The findings from this 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.
4. EVALUATION OF PPG TREATMENT USING HETEROGENEOUS MODEL

4.1. INTRODUCTION

The objective of this chapter is to evaluate the effect of PPG in improving the oil recovery and injection profile of a parallel heterogeneity model without crossflow. The results of the previous chapter shows that PPG can cause a significant permeability reduction to higher core permeability using the right design parameters.

Therefore, an experimental study was carried out to investigate effect of different permeability contrast model on improving the oil recovery of the unswept low permeability zone using PPG. The model was designed to have two layers representing the low permeability and high permeability zone without cross-flow. The low permeability zone will be altered in subsequent experiments while the high permeability is kept near constants and oil recovery factor and injection profiles from these varying zones were closely monitored before, during and after PPG injection to study the effect of reservoir heterogeneity. The PPG used will be placed near wellbore of the injection well to correct the inter-layer heterogeneity or heal fracture.

4.2. EXPERIMENTAL MATERIALS

4.2.1. Preformed Particle Gel (PPG). The PPG used in this study is commercial LiquiBlock 40F with the mesh size of 170-200. 2000ppm PPG was prepared using 1wt. % NaCl.

4.2.2. Sand Grains. Quartz sands with three different mesh sizes 18-20, 60-80, 100-120 were selected in this study to obtain the desirable low and high permeability.

4.2.3. Brine. The brine selected is 1wt. % NaCl.

4.2.4. Mineral Oil. Mineral oil with a viscosity of 192cp
4.3. EXPERIMENTAL SETUP

The parallel heterogeneity model setup as shown in Figure 4.1 consists of Isco syringe pump, two sandpack tubes, oil accumulator, PPG accumulator with magnetic stir, pressure gauge and test tubes. The Isco syringe pump was used to inject brine, oil and PPG into the sandpack. The dimensions for each of the two sandpack tubes were 20 cm in length and 2.6 cm in diameter and were connected in parallel without crossflow. The oil accumulator which has 600 ml capacity contains the heavy oil. The PPG accumulator has a magnetic stir to keep the PPG in suspension. The pressure gauge was connected at the inlet of the sandpack tube to record injection pressures. The test tubes was kept at the outlet to collect effluent.

![Figure 4.1. Parallel Heterogeneity Model Setup](image)

4.4. EXPERIMENTAL PROCEDURES

The procedures for carrying out the parallel heterogeneity model experiments were briefly described as follows:

4.4.1. Preparing the Sandpack:

1. Select the mesh size of the sand depending on the desired permeability.
2. Measure the dimensions of the two sandpack tubes (low and high permeability).
3. Fasten on one end (producer) of the sandpack tube with a screen filter in place, and then begin pouring the sand in from the other end (injector).
4. Regularly pour small amounts of sand until the entire packs is filled with sand.
5. Level the sand at the open end of the sand pack tube and fasten the remaining end with a screen filter in place.

4.4.2. Measuring Porosity:
1. Vacuum the sandpack tube from the producer end for at least 5 hrs until all the air is removed and weigh the sandpack tube to get the dry weight.
2. Prepare 1wt.% NaCl brine by mixing 1 g of NaCl with 99 g of distilled water
3. Fill the pump with the brine and inject 1 wt. % brine to saturate the sandpack tube at the flowrate of 1 mil/min.
4. Record the time for the brine to completely saturate the sand pack
5. Once the sand pack is fully saturated with brine, weigh the sand pack to determine the wet weight
6. Calculate the difference between the dry weight and wet weight to determine the pore volume (PV)
7. Calculate the bulk volume of the sand pack tube
8. Calculate the porosity.

4.4.3. Measuring Absolute Permeability:
1. Inject 1 wt.% NaCl brine to each sandpack tube separately at the flow rate of 1, 2, 3, 4, 5, 6 mil/min
2. Record the injection stable pressure for each flow rate
3. Calculate the absolute permeability of the sandpacks using Darcy Law.

4.4.4. Oil Saturation Procedures:
1. Saturate the sandpack separately by injecting mineral oil from the oil accumulator at a flowrate rate of 1 mil/min until no water is produced
2. Record the volumes of fluids produced from each of the sand pack during the oil saturation to determine their irreducible water saturation (Swi), initial oil saturation (Soi) and original oil in place (OOIP).
4.4.5. Water flood before PPG Injection:
1. Horizontally position the sandpack tubes in parallel with the injector inlet facing the pump and producer outlet facing the effluent test tubes
2. Connect the pressure transducer to the tee connections on the inlet of the high and low permeability sandpack tubes
3. Inject 1 wt. % NaCl at flowrate of 1 mil/min to the high and low permeability sandpack tube connected in parallel until no oil is produced (100% water cut) and stabilized pressure is obtained.
4. Record the time, brine injection pressure and volume of oil and water produced from the effluent test tubes.
5. Calculate the oil recovery factor, water cut and injection profile from the brine PV injected

4.4.6. PPG Injection Procedures:
1. Prepare the PPG suspension using 170-200 mesh PPG with a concentration of 2000 ppm
2. Pour the prepared PPG into the PPG accumulator with magnetic stir accumulated to stir
3. Inject 0.5PV (High K) to the sandpack tubes connected in parallel at flowrate of 1 mil/min
4. Record the time, PPG injection pressure and volume of oil and water produced from the effluent test tubes.
5. Calculate the oil recovery factor, water cut and injection profile from the PPG PV injected

4.4.7. WaterFlood after PPG Injection Procedures:
1. Inject 1 wt. % NaCl to the sandpack tubes until no oil is produced (100% water cut) and stabilized pressure was obtained
2. Record the time, pressure and volume of oil and water produced from the effluent test tubes.
3. Calculate the oil recovery factor and water cut and injection profile from the brine PV injected
   The above procedures were repeated for each experiment and the oil recovery factor, water cut and injection profile were all plotted against the cumulative fluid PV injected.

4.5. PERMEABILITY CONTRAST

   The contrast between the high permeability and low permeability zone is an important factor to be considered as it determines how heterogeneous a reservoir can be, which can significantly affect the reservoir sweep efficiency. In this study, three models were carried out with varying permeability contrasts. The first model has a permeability contrast of 44 between the high permeability and low permeability zone. The second model has a permeability contrast of 20 while the third model has a permeability contrast of 4.

   The high permeability sandpack was kept near constant for all the three models carried out while the low permeability sandpack was varied. The essence of this is to investigate the effect the PPG has on plugging the high permeability zone and diverting waterflood to the low permeability zone. This will help improve sweep efficiency and displacement efficiency.

   The injection profiles, oil recovery factors, water cut, injection pressures of each of the low permeability and high permeability sandpacks were closely monitored before, during and after PPG injection.

4.6. RESULTS ANALYSIS AND DISCUSSIONS

4.6.1. Permeability Contrast of 44. Table 4.1 summarizes the sand pack properties of the low and high permeability zone. The table shows the permeability, sand grains mesh sizes, pore volume, porosity, irreducible water saturation and original oil in place for this experiment.
The pore volume (PV) of the sandpacks which is the difference in weight between the saturated sandpack tube and the dry sandpack tube were calculated using Equation 4.1 below:

\[ V_p = W_s - W_d \]  

where \( V_p \) is the pore volume, \( W_s \) is the saturated weight, and \( W_d \) is the dry weight of the sandpacks tube.

Porosity of the sandpacks which is the percentage of pore volume or void spaces within rock that can contain fluids were calculated using Equation 4.2 below:

\[ \text{Porosity} = \frac{V_p}{V_b} \]  

where \( V_p \) is the pore volume and \( V_b \) is the bulk volume.

The irreducible water saturation (Swi) which is the lowest water saturation that can be achieved in the sandpacks by displacing the water by oil was calculated using Equation 4.3 below:

\[ S_{wi} = 1 - S_w \]  

Where \( S_w \) is the water saturation.

The original oil in place (OOIP) which is the volume of oil of the sandpacks prior to production was calculated using the Equation 4.4 below:

\[ OOIP = S_{oi} \times PV \]  

where \( S_{oi} \) is the initial oil saturation and \( PV \) is the sandpack pore volume.

### Table 4.1. The Sandpack Properties for Permeability Contrast of 44

<table>
<thead>
<tr>
<th>Permeability (Darcy)</th>
<th>Sand Grains Mesh Size</th>
<th>Pore Volume (cc)</th>
<th>Porosity (%)</th>
<th>Swi (%)</th>
<th>OOIP (cc)</th>
</tr>
</thead>
<tbody>
<tr>
<td>High K – 22.1</td>
<td>18-20</td>
<td>41.87</td>
<td>34.84</td>
<td>26</td>
<td>30.8</td>
</tr>
<tr>
<td>Low K – 0.5</td>
<td>100-120</td>
<td>24.9</td>
<td>20.72</td>
<td>12</td>
<td>21.8</td>
</tr>
</tbody>
</table>
4.6.1.1 Permeability measurement. Permeability which is the measure of ability of fluids to flow through a rock was very vital in this experiment as its one of the key factor to study the effect of reservoir heterogeneity on oil recovery. Sand mesh size of 18-20 was selected to prepare the higher permeability sandpack while sand mesh size of 100-120 was selected to prepare the lower permeability sandpack. 1wt. % NaCl at six different flowrates (1, 2, 3, 4, 5, 6mil/min) was injected and the stable injection pressure for each flowrate was obtained. Darcy Law (Equation 3.2) was applied from the pressure drop obtained to calculate the absolute permeability of each of the sandpacks. Figure 4.2 shows the injection pressure changes with injection flowrate to obtain the high absolute permeability of 22.1darcy while Figure 4.3 shows the injection pressure changes with injection flowrate to obtain the low absolute permeability of 0.5darcy for the sandpacks.

![Figure 4.2. Injection pressure changes with injection flowrate for the low K](image1)

![Figure 4.3. Injection pressure changes with injection flowrate for the low K](image2)
4.6.1.2 Injection pressure. Injection pressure monitoring is important in determining the success of PPG treatment. It is expected that PPG treatment is accompanied with an increase in the injection pressure. In this first experiment, the pressure transducers mounted on the inlet of the injection point were carefully monitored on the computer monitor screen to study the injection pressure profile. Figure 4.4 show the injection pressure changes with cumulative time of the sandpacks. The injection stable pressure before PPG Injection was 0.3psi after 120mins, then 0.5PV of PPG was injected, the injection pressure rose to 7psi during PPG injection. After PPG injection, the injection pressure dropped to a stable pressure of 4.6psi after 257mins.

![Injection Pressure for K Contrast of 44](image)

Figure 4.4. Injection Pressure changes with Cumulative Time for the sandpacks

4.6.1.3 Injection profile. Injection profile is one of the most common reservoir problem identification methods. Injection profile log measures water injection profile to obtain real time water intake profile for determining vertical heterogeneity. Profile control targets on improving the injection profile of an injection well and thus improves sweep efficiency. PPG which is a plugging agent is injected into an injection well to reduce injection phase absorbing ability of high permeability zone. Small amounts of PPGs are injected to seal or partially seal high permeability zones.
Figure 4.5 above shows that during the waterflood before PPG injection, most of the injection brine goes to the high permeability sandpack (22.1d), then during PPG injection, the profile changed indicating that the PPG is gradually plugging the high permeability zone. Then after PPG injection, PPG partially block the high permeability zone and diverted less of the brine injected to the unswept low permeability sandpack (0.5d). Table 4.2 shows the split of flow between the low and high permeability sandpacks for permeability contrast of 44 and they were calculated using the equation below.

Table 4.2 illustrates that 99.81% of total injected fluids volume went to the high permeability sandpack while 0.19% of total fluids volume injected went to low permeability sandpack before PPG Injection. During PPG Injection, the total fluids volume from high permeability sandpack reduced from 99.81% to 99.39% while the total fluids volume from low permeability sandpack increased slightly from 0.19% to 0.61%. After PPG Injection, the total fluids volume from high permeability sandpack further reduced from 99.39% to 81.70% while the total fluids volume from low permeability sandpack increased to 18.30%.
Table 4.2. Fluid Distribution showing the split of flow between low and high K sandpack permeability.

<table>
<thead>
<tr>
<th>Permeability (Darcy)</th>
<th>Split of Flow (percent)</th>
<th>Before PPG Injection</th>
<th>During PPG Injection</th>
<th>After PPG Injection</th>
</tr>
</thead>
<tbody>
<tr>
<td>High K – 22.1</td>
<td>99.81</td>
<td>99.39</td>
<td>81.70</td>
<td></td>
</tr>
<tr>
<td>Low K – 0.5</td>
<td>0.19</td>
<td>0.61</td>
<td>18.30</td>
<td></td>
</tr>
</tbody>
</table>

The split of flow between the low and high permeability sandpack was calculated using the Equation 4.5 below.

\[
Split\ of\ Flow = \left[ \frac{V_H}{(V_H + V_L)} \right] \times 100\% \tag{Equation\ 4.5}
\]

Where \( V_H \) is the volume of total fluids injected to the high permeability zone and \( V_H \) is the volume of total fluids injected to the low permeability zone.

**4.6.1.4 Oil recovery factor.** The recovery factor is the recoverable amount of hydrocarbon initially in place, normally expressed as a percentage. The recovery factor is a function of the displacement mechanisms. The oil recovery in this study can be expressed as the percentage of the oil originally in place (OOIP) produced from the heterogeneous model. It can be calculated using the Equation 4.6 below.

\[
Oil\ Recovery\ Factor = \frac{Volume\ of\ Oil\ Produced}{Total\ OOIP} \tag{Equation\ 4.6}
\]

The oil recovery is an important factor to be considered as it measures the sweep efficiency of a waterflooded reservoir. It is expected that after PPG treatment, the oil production rate should increase. In this study, the high, low permeability and total oil recovery sandpacks were closely monitored to see the effect of this permeability contrast.
Figure 4.6 below shows the oil recovery of the high permeability sandpack, before PPG injection was 52.27%, during PPG injection the oil recovery remained the same but increased slightly to 52.92% after PPG injection. The pore volume from the high K sandpack

![High K Oil Recovery](image)

Figure 4.6. Oil recovery changes with cum. fluid injected for the high K sandpack

Figure 4.7 below shows that the oil recovery of the low permeability sandpack before PPG injection was 0.92%, during PPG injection, the oil recovery increased slightly to 3.21% and then increased significantly to 38.53% after PPG injection. The result indicates that PPG treatment improved the sweep efficiency of the low permeability sandpack by diverting the displacing fluid to the low permeability zone.
Figure 4.7. Oil recovery changes with cum. fluid injected for the low K sandpack

The difference in the pore volume injected as shown in figure 4.6 and figure 4.7 is because the high K sandpack has a total pore volume of 41.87 cm$^3$ while the low K sandpack has a total pore volume of 24.9 cm$^3$.

Combining the high and low permeability oil recovery factor of the sandpacks as shown in Figure 4.8 for the permeability contrast of 44, a total oil recovery of 30.99% was obtained before PPG injection while a total oil recovery of 31.94% was obtained during PPG injection and a total oil recovery of 46.96% was gotten after PPG injection.

Figure 4.8. Total Oil Recovery
4.6.1.5 Water cut. Water cut is ratio of water produced compared to the volume of total liquids produced expressed in percentage. In heterogeneous matured reservoirs, water production is significantly higher than oil production. Water cut can be expressed using the Equation 4.7 below. As shown in Figure 4.9 above, 1.8PV of 1 wt. % NaCl was injected to displace the oil out of the sandpack until no oil is produced and 100% water was obtained. 0.5PV of PPG was injected thereafter and the water cut reduced gradually from 100% to 80%. Then after PPG injection, 1.7PV of 1 wt. % NaCl was injected again, the watercut increase gradually from 80% until it gets to 100%.

\[
\text{Water Cut (Fw)} = \left( \frac{V_{wp}}{V_t} \right) \times 100\%
\]

Equation 4.7

where \(V_{wp}\) is the volume of water produced and \(V_t\) is the volume of total liquids produced.
4.6.2. Permeability Contrast of 20. Table 4.3 summarizes the sand pack properties of the low and high permeability zone. The table shows the permeability, sand grains mesh sizes, pore volume, porosity, irreducible water saturation and original oil in place for this experiment.

<table>
<thead>
<tr>
<th>Permeability (Darcy)</th>
<th>Sand Grains Mesh Size</th>
<th>Pore Volume (cc)</th>
<th>Porosity (%)</th>
<th>Swi (%)</th>
<th>OOIP (cc)</th>
</tr>
</thead>
<tbody>
<tr>
<td>High K – 22.4</td>
<td>18-20</td>
<td>32.60</td>
<td>30.72</td>
<td>27</td>
<td>21.93</td>
</tr>
<tr>
<td>Low K – 1.1</td>
<td>60-80</td>
<td>35.40</td>
<td>33.35</td>
<td>18</td>
<td>32.60</td>
</tr>
</tbody>
</table>

4.6.2.1 Permeability measurement. Sand mesh size of 18-20 was used to prepare the high permeability sandpack while sand mesh size of 60-80 was used to prepare the low permeability sandpack. 1wt. % NaCl at six different flowrates (1, 2, 3, 4, 5, and 6mil/min) was injected and the stable injection pressure for each flowrate was obtained. Darcy Law (Equation 3.2) was applied from the pressure drop obtained to calculate the absolute permeability of each of the sandpacks. Figure 4.10 shows the injection pressure changes with injection flowrate to obtain the high absolute permeability of 22.4darcy while Figure 4.11 shows the injection pressure changes with injection flowrate to obtain the low absolute permeability of 1.1darcy for the sandpacks.
Figure 4.10. Injection pressure changes with injection flowrate for the high K sandpack

Figure 4.11. Injection pressure changes with injection flowrate for the low K sandpack
4.6.2.2 Injection pressure. Figure 4.12 shows the injection pressure changes with cumulative time of the sandpacks. The injection stable pressure during the waterflood before PPG Injection was 0.2psi after 146mins, then 0.5PV of PPG was injected and the injection pressure rose to 9psi during PPG injection. After PPG injection, the injection pressure dropped to a stable pressure of 7psi after injecting 1 wt. % NaCl.

![Injection Pressure for K Contrast of 20](image)

Figure 4.12. Injection pressure changes with cumulative time for the sandpacks

4.6.2.3 Injection profile. Figure 4.13 shows that during the waterflood before PPG injection, most of the brine injected goes to the high permeability sandpack then during PPG injection, the profile changed indicating that the PPG is gradually plugging the high permeability zone. Then after PPG injection, PPG partially block the high permeability zone and diverted less of the brine injected to the unswept low permeability sandpacks.

![Injection Profile for the K Contrast of 20](image)

Figure 4.13. Injection Profile changes with cumulative time for the sandpack
Table 4.4. Fluid Distribution showing the split of flow between low and high K Permeability (Darcy) showing the split of flow between low and high K Permeability (Darcy)

<table>
<thead>
<tr>
<th>Permeability (Darcy)</th>
<th>Split of Flow (percent)</th>
<th>Before PPG Injection</th>
<th>During PPG Injection</th>
<th>After PPG Injection</th>
</tr>
</thead>
<tbody>
<tr>
<td>High K – 22.4</td>
<td></td>
<td>99.62</td>
<td>96.68</td>
<td>84.47</td>
</tr>
<tr>
<td>Low K – 1.1</td>
<td></td>
<td>0.38</td>
<td>3.32</td>
<td>15.53</td>
</tr>
</tbody>
</table>

Table 4.4 illustrates that 99.62% of total fluids volume injected went to the high permeability sandpack while 0.38% of total fluids volume injected went to low permeability sandpack before PPG Injection. During the injection of PPG, the total fluids volume from high permeability sandpack reduced from 99.62% to 96.68% while the total fluids volume from low permeability sandpack increased slightly from 0.38% to 3.32%. After the Injection of PPG, the total fluids volume from high permeability sandpack further reduced to 84.47% while the total fluids volume from low permeability sandpack increased to 15.53%.

4.6.2.4 Oil recovery factor. Figure 4.14 below shows the oil recovery factor was 80.72% before, during and after injecting 0.5PV PPG for the high permeability sandpack while Figure 4.15 below shows that the oil recovery of the low permeability sandpack before PPG injection was 1.89%, during PPG injection the oil recovery increased to 17.75% and after PPG injection, the oil recovery increases largely to 60.66%. The result indicates that PPG treatment improved the oil recovery of the low permeability sandpack by diverting the displacing fluid to the lower permeability zone.
Figure 4.14. Oil recovery factor changes with cum. PV injected for the high K sandpack

Figure 4.15. Oil recovery factor changes with cum. PV injected for the low K sandpack

The difference in the pore volume injected as shown in figure 4.14 and figure 4.15 is because the high K sandpack has a total pore volume of 32.60 cm³ while the low K sandpack has a total pore volume of 35.40 cm³.

Also, combining the high and low permeability oil recovery factor of the sandpacks for the permeability contrast of 20 as shown in Figure 4.16, a total oil recovery of 35.8% was obtained before PPG injection while a total oil recovery of 44.82% was obtained during PPG injection and a total oil recovery of 69.3% was gotten after PPG injection.
4.6.2.5 Water cut. Figure 4.17 shows that 2PV of 1 wt. % NaCl was injected to displace the oil out of the sandpack until no oil is produced and 100% water cut was obtained. 0.5PV of PPG was injected thereafter and the water cut reduced gradually from 100% to 33%, then after PPG injection, 4PV of 1 wt. % NaCl was injected again and the watercut increase gradually from 33% until it gets to 100%.
4.6.3. Permeability Contrast of 4. Table 4.5 summarizes the sand pack properties of the low and high permeability zone. The table shows the permeability, sand grains mesh sizes, pore volume, porosity, irreducible water saturation and original oil in place for this experiment.

Table 4.5. The Sandpack Properties for Permeability Contrast of 4

<table>
<thead>
<tr>
<th>Permeability (Darcy)</th>
<th>Sand Grains Mesh Size</th>
<th>Pore Volume (cc)</th>
<th>Porosity (%)</th>
<th>Swi (%)</th>
<th>OOIP (cc)</th>
</tr>
</thead>
<tbody>
<tr>
<td>High K – 21.7</td>
<td>18-20</td>
<td>35.7</td>
<td>33.64</td>
<td>25</td>
<td>26.70</td>
</tr>
<tr>
<td>Low K – 6.2</td>
<td>18-20</td>
<td>39.60</td>
<td>37.31</td>
<td>8</td>
<td>36.60</td>
</tr>
</tbody>
</table>

4.6.3.1 Permeability measurement. Sand mesh size of 18-20 was used to prepare the high permeability sandpack and the low permeability sandpack. 1 wt.% NaCl at six different flowrates (1, 2, 3, 4, 5, 6mil/min) was injected and the stable injection pressure for each flowrate was obtained. Darcy Law (Equation 3.2) was applied from the pressure drop obtained to calculate the absolute permeability of each of the sandpacks. Figure 4.18 shows the injection pressure changes with injection flowrate to obtain the high absolute permeability of 21.7 darcy while Figure 4.19 shows the injection pressure changes with injection flowrate to obtain the low absolute permeability of 6.2 darcy for the sandpacks.

![High K - 21.7darcy](image)

Figure 4.18. Injection pressure changes with injection flowrate for the high permeability sandpack
4.6.3.2 Injection pressure. Figure 4.20 shows the injection pressure changes with fluid injected for the sandpacks. The injection stable pressure before PPG Injection was 0.2psi after, then 0.5PV of PPG was injected and the injection pressure rose to 5.1psi during PPG injection. After PPG injection, the injection pressure dropped to a stable pressure of 1.5psi after injecting 1 wt. % NaCl.
4.6.3.3 Injection profile. Figure 4.21 shows that during the waterflood before PPG injection, most of the brine injected goes to the high permeability sandpack then during PPG injection, the profile changed indicating that the PPG is gradually plugging the high permeability zone. Then after PPG injection, PPG fully blocked the high permeability zone and diverted all of the brine injected to the unswept low permeability sandpack.

![Injection Profile for K Contrast of 4](image)

Figure 4.21. Injection Profile changes with cumulative time for the sandpacks

Table 4.6. Fluid Distribution showing the split of flow between low and high sandpack

<table>
<thead>
<tr>
<th>Permeability (Darcy)</th>
<th>Split of Flow (percent)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Before PPG Injection</td>
</tr>
<tr>
<td>High K – 21.7</td>
<td>95.26</td>
</tr>
<tr>
<td>Low K – 6.2</td>
<td>4.7</td>
</tr>
</tbody>
</table>

Table 4.6 illustrates that 95.26% of total fluids volume injected went to the high permeability sandpack while 4.7% of total fluids volume injected went to low permeability sandpack before the injection of PPG. During the injection of PPG, the total fluids volume from high permeability sandpack decreased from 95.26% to 92.50% while the total fluids volume from low permeability sandpack increased significantly from
4.7% to 7.50%. After the injection of PPG, the total volume of fluids from the high permeability sandpack decreased significantly to 35.07% while the total volume of fluids from the low permeability sandpack increase significantly to 64.93%. This result indicates that PPG treatment significantly improved the sweep efficiency of the permeability contrast of 4.

4.6.3.4 Oil recovery factor. Figure 4.22 below shows the oil recovery factor for the high permeability sandpack was 80.15% before, during and after injecting 0.5PV PPG while Figure 4.23 below show that the oil recovery of the low permeability sandpack before PPG injection was 20.25%, during PPG injection the oil recovery increased to 30.7% and after PPG injection, the oil recovery increases largely to 93.15%. The result indicates that PPG treatment improved the oil recovery of the low permeability sandpack significantly by diverting the displacing fluid to the lower permeability zone.

![High K Oil Recovery](image)

Figure 4.22. Oil recovery factor changes with cum. PV injected for the high K sandpack
Figure 4.23. Oil recovery factor changes with cum. PV injected for the low K sandpack

The difference in the pore volume injected as shown in figure 4.22 and figure 4.23 is because the high K sandpack has a total pore volume of 35.7 cm$^3$ while the low K sandpack has a total pore volume of 39.60 cm$^3$.

Also, combining the high and low permeability oil recovery factor of the sandpack for the permeability contrast of 4, a total oil recovery of 45.6% was obtained before PPG injection while a total oil recovery of 51.64% was obtained during PPG injection and a total oil recovery of 87.64% was gotten after PPG injection as shown in Figure 4.24.

Figure 4.24. Total oil recovery factor for the permeability contrast of 4
4.6.3.5 Water cut. Figure 4.25 shows that 2PV of 1 wt.
% NaCl was injected to displace the oil out of the sandpack until 94% water cut was obtained. 0.5PV of PPG was injected thereafter and the water cut reduced gradually from 94% to 10%. Then after PPG injection, 4PV of 1 wt.
% NaCl was injected again and the watercut increase gradually from 10% until it gets to 100%.

![Water Cut for K Contrast of 4](image)

Figure 4.25. Water cut changes with cumulative PV injected for the sandpacks

4.7. EFFECT OF PERMEABILITY CONTRAST

The results of the permeability contrast models of 44, 20 and 4 were compared to study the effect of the permeability contrast on oil recovery. These comparisons were carefully monitored before PPG injection, during PPG injection and after PPG injection. The result will investigate the sweep efficiency and the displacement efficiency potentials of PPG.

From the results as shown in Table 4.7 and Figure 4.26 to Figure 4.28, the model with a permeability contrast of 44 had an increased high permeability oil recovery of 0.65%, low permeability oil recovery of 37.61% and total oil recovery 15.97%. The model with the permeability contrast of 20 had an increased high permeability oil recovery of 0%, low permeability oil recovery of 58.77% and total oil recovery of 33.5%. The model with the permeability contrast of 4 had an increased high permeability oil recovery of 0%, low permeability oil recovery of 72.9% and total oil recovery 42.04%. Thus results indicates that PPG treatment improved the oil recovery of the low
permeability sandpack significantly by diverting waterflood fluids to the unswept zone which in return improves the sweep efficiency and displacement efficiency.

Table 4.7. The Incremental Oil Recovery Results

<table>
<thead>
<tr>
<th></th>
<th>High K</th>
<th>Low K</th>
<th>High K</th>
<th>Low K</th>
<th>High K</th>
<th>Low K</th>
<th>Total Oil Recovery</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>44 times</td>
<td>20 times</td>
<td>4 times</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Before PPG (%)</td>
<td>52.27</td>
<td>0.92</td>
<td>30.99</td>
<td>1.89</td>
<td>35.80</td>
<td>80.15</td>
<td>20.25</td>
</tr>
<tr>
<td>PPG Inj (%)</td>
<td>52.27</td>
<td>3.21</td>
<td>31.94</td>
<td>17.75</td>
<td>44.82</td>
<td>80.15</td>
<td>30.7</td>
</tr>
<tr>
<td>After PPG (%)</td>
<td>52.92</td>
<td>38.53</td>
<td>46.96</td>
<td>60.66</td>
<td>69.3</td>
<td>80.15</td>
<td>93.15</td>
</tr>
<tr>
<td>Increased Oil Recovery (%)</td>
<td>0.65</td>
<td>37.61</td>
<td>15.97</td>
<td>0.0</td>
<td>33.5</td>
<td>0.0</td>
<td>72.9</td>
</tr>
</tbody>
</table>

Figure 4.26. The effect of Permeability Contrast on Low K Oil Recovery
Figure 4.27. The Effect of Permeability Contrast on High K Oil Recovery

Figure 4.28. The Effect of Permeability Contrast on Total Oil Recovery
Table 4.8. Comparison of Fluid Distribution and Oil Recovery Results

<table>
<thead>
<tr>
<th>K Contrast Models</th>
<th>Permeability (Darcy)</th>
<th>Split of Flow</th>
<th>Oil Recovery</th>
<th>Total Oil Recovery</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>Before PPG (%)</td>
<td>After PPG (%)</td>
<td>Before PPG (%)</td>
</tr>
<tr>
<td>44</td>
<td>22.1</td>
<td>99.81</td>
<td>81.70</td>
<td>52.27</td>
</tr>
<tr>
<td></td>
<td>0.5</td>
<td>0.19</td>
<td>18.30</td>
<td>0.92</td>
</tr>
<tr>
<td>20</td>
<td>22.4</td>
<td>99.62</td>
<td>84.47</td>
<td>80.72</td>
</tr>
<tr>
<td></td>
<td>1.1</td>
<td>0.38</td>
<td>15.53</td>
<td>1.89</td>
</tr>
<tr>
<td>4</td>
<td>21.7</td>
<td>95.26</td>
<td>35.07</td>
<td>80.15</td>
</tr>
<tr>
<td></td>
<td>6.2</td>
<td>4.74</td>
<td>64.93</td>
<td>20.25</td>
</tr>
</tbody>
</table>

In general, the change of injection profile is an important method to evaluate the effectiveness of PPG treatment. Table 4.8 compares the split of flow and oil recovery before and after PPG treatment. It can be seen that PPG treatment can improve both the sweep efficiency and displacement efficiency by correcting the reservoir heterogeneity.
5. CONCLUSION AND RESEARCH BENEFITS

This chapter summaries the conclusions drawn from the evaluation of preformed particle gel (PPG) treatment discussed in chapters 3 and 4. It also discussed on the benefits of this research.

5.1. CONCLUSIONS

This research supports the following conclusion on the evaluation of PPG treatment using the homogeneous and heterogeneous models:

1. The swelling ratio of PPG was affected by the concentration of brine. PPG swells more with 0.05 wt. % NaCl than with 0.25%, 1% and 10 wt. % NaCl.
2. The gel strength of PPG was higher using 10 wt. % NaCl than using the lesser 1%, 0.25% and 0.05 wt. % NaCl.
3. PPG prepared with 0.05 wt. % NaCl lead to higher injection pressures and core permeability reduction to the ~4 mD and ~26 mD cores than PPG prepared with 1 wt. % and 10 wt. % NaCl. This shows that PPG prepared with 0.05 wt. % NaCl was more deformable and penetrated deep into the sandstone cores than the rest of the concentration of brine used in the homogeneous model.
4. The permeability reduction was more significant using the ~26 mD cores than using the ~4 mD cores. This shows that PPG can actually penetrate deep to reduce the permeability of high permeability zone.
5. The oil recovery from the low permeability sandpack of all the permeability contrast models increased during and after injection of PPG.
6. The parallel heterogeneity experiment result shows that the injection of PPG yielded an incremental total oil recovery of 15.97%, 33.5% and 42.04% for the permeability contrast models of 44, 20 and 4 respectively.
7. The water cut during the injection of PPG decrease for all the permeability contrast model and increased gradually after the injection of PPG.
8. The injection pressure increased during the injection of PPG and reduced slightly after the injection of PPG injection until a stable pressure is reached for all the permeability contrast models.

9. The injection profile results show that the fluids distribution for the high permeability sandpacks dropped during and after the injection of PPG while the fluids distribution for the low permeability sandpack increased for the permeability contrast models. This show that the injection profiles of all the permeability contrast models were modified after PPG treatment.

10. The results of the incremental oil recovery and modified injection profiles suggest that PPG treatment successfully improved the sweep efficiency of the permeability contrast models.

5.2. RESEARCH BENEFITS

This benefits of the research includes the following:

1. The laboratory data obtained in this research is useful in developing numerical tools to solve the excess water production problems and increase oil recovery.

2. Reservoir that would be a good candidate for conformance control could easily be identified

3. This research will provide a cost-estimate for experiments designed to mimic heterogeneity

4. It will provide better mechanistic understanding of PPG process for field projects.


VITA

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