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Evaluation of EOR potential of low salinity polymer in enhancing heavy oil recovery on the Alaska North Slope

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EVALUATION OF EOR POTENTIAL OF LOW SALINITY POLYMER IN

ENHANCING HEAVY OIL RECOVERY ON THE ALASKA NORTH SLOPE

by

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ABSTRACT

Alaska's North Slope (ANS) contains vast amount of viscous oil resources that have not been extracted. This study focuses on the investigation over the potential shown by low-salinity polymer flooding in improving the recovery of ANS heavy oil through laboratory experiments.

At the beginning, coreflooding experiments were performed with silica sandpacks. The synergy between low-salinity water flooding and polymer flooding was proved, and the low-salinity polymer showed a better performance than the normal-salinity polymer. Further, the sandpacks prepared with formation sand from an oilfield on the ANS was then employed so as to simulate the reservoir condition. A series of experiments were carried out to investigate the effect imposed by the original wettability of the sand on the performance of oil recovery and the optimization of the injection sequence of the polymer solution. Moreover, this research studied the effect imposed by the starting time of polymer flooding on the oil recovery performance.

It has been shown by all these experiments that low-salinity water flooding can recover more oil even after extensive normal-salinity water flooding. The low-salinity polymer flooding can produce more oil (3%-10% OOIP) even after extensive normal-salinity water flooding, low-salinity water flooding and polymer flooding. Starting from polymer flooding, the higher recovery efficiency can be achieved by about 10%. Wettability has a significant impact on the initial performance of water injection. The injection sequence of polymers with different salinities can affect the performance of oil recovery to a significant extent.

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NOMENCLATURE

Symbol	Description
ANS	Alaska’s North Slope
Fr	resistance factor
Frr	residual resistance factor
EOR	enhanced oil recovery;
HSWF	high salinity water flooding, salinity=27500 ppm;
LSE	low salinity effect
LSPF	low salinity polymer flooding.
LSWF	low salinity water flooding, salinity=2498 ppm;
PF	polymer flooding;
SLSWF	softened low salinity water flooding, salinity=2498 ppm
SFB	synthetic formation brine
SIB	synthetic injection brine
ULSWF	ultra-low salinity water flooding, salinity=250 ppm;

1. INTRODUCTION

Alaska North Slope (ANS) (Figure 1.1) is rich in heavy oil resources, concentrated in the West Sak (also known as Schrader Bluff) and Ugnu reservoirs. The total OOIP in these reservoirs was estimated to be between 20 and 25 billion barrels, with approximately two-thirds of the heavy oil lying under the Kuparuk River Unit (Targac et al. 2005). Until May 2017, all ANS fields produced only 56,000 b/d of heavy oil. Thermal and gas injection methods are successful techniques for enhancing heavy oil recovery in many parts of the world, but not feasible for ANS due to environmental and economical concerns. The performance of water flooding is poor as the difference in viscosity between heavy oil and water can cause injected liquids to quickly enter producers. Large amounts of oil is left untouched in the reservoirs. The recovery factor by water flooding is usually less than 20% or even less than 10% (Gao, 2011). Using chemicals to increase the viscosity of the displacing phase, e.g. by thickening water with polymer, has been attracting more and more attention during the recovery of heavy oil on the ANS.

Preliminary laboratory and simulation studies show that polymer flooding has an excellent potential to improve the recovery of Schrader Bluff heavy oil reservoirs (Seright 2010, 2011), but to date, no large-scale polymer flooding has occurred in the United States and other unconventional resources. Preliminary studies have shown that the successful implementation of polymer flooding can remarkably increase heavy oil recovery on the ANS. Polymer flooding has been successful in heavy oil reservoirs both at the laboratory and pilot scales (Seright 2017; Wang et al. 2007, 2009). For the first time, heavy oil polymer flooding tests will be conducted at Milne Point Oilfield on the ANS.

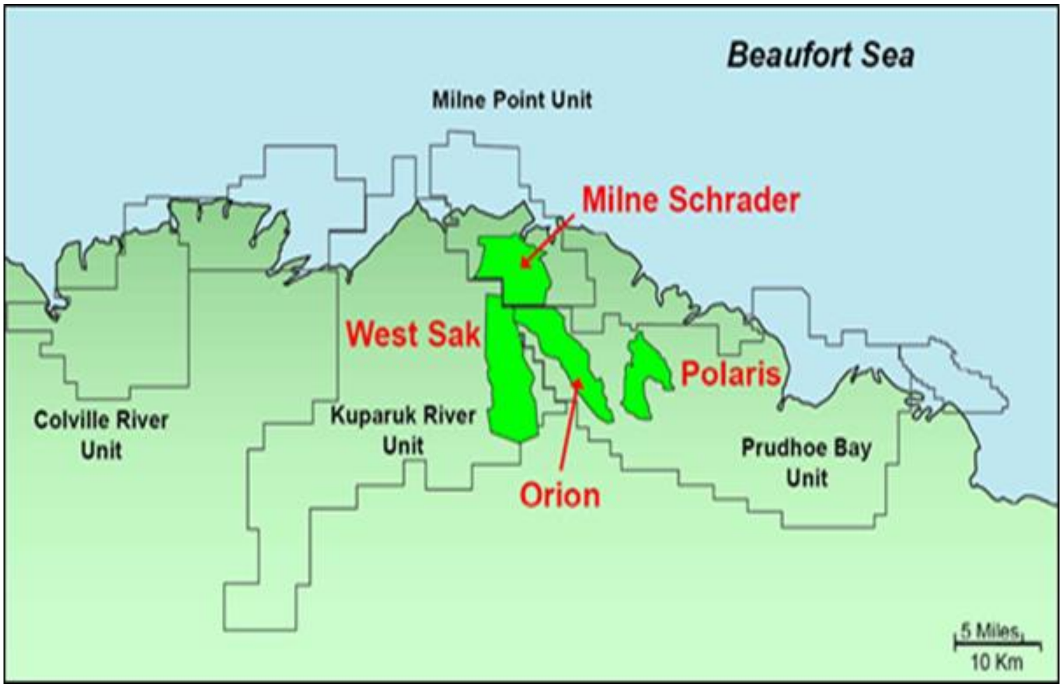

Figure 1.1 Alaska’s Viscous Oil Reserves, BP Exploration Alaska (Inc.) presentation to Alaska Department of Revenue.

The conventional view is that polymers are mainly used to improve sweeping efficiency, but have little effect on the improvement of microscopic displacement efficiency by reducing reduce residual oil saturation. In contrast, it has been widely reported that low-salinity water flooding can significantly reduce residual oil saturation in conventional reservoirs by changing formation wettability (Morrow and Buckley 2011), but the effect is limited in heavy oil reservoirs due to low sweep efficiency. The salinity of the polymer solution has a significant influence on the polymer viscosity, which is one of the key factors dominating the oil recovery performance of a polymer flooding project.

The viscosity decreases significantly with the increase of salinity and content of divalent ions (Levitt et al., 2008). Polymer retention (adsorption) in the porous media also depends on the salinity and hardness (Manichand and Seright 2014). Is low salinity is favorable for the polymer flooding? Or in another way: Is there any synergy effect by combining the low salinity water and polymer flooding? A series of experiments were carried out in this study to testify the synergy effect and to explore favorable conditions to maximize the polymer flooding performance in enhancing the heavy oil recovery on the ANS.

1.1. OBJECTIVES OF THIS RESEARCH

The major objective of this study was to test whether and how much low salinity water/polymer could improve the heavy oil recovery efficiency by carrying out coreflooding experiments.

Another objective was to explore favorable conditions to maximize the oil recovery performance. In this aspect, the effect of original wettability of the porous media, the injection sequence of polymer solutions and the starting time of polymer injection on oil recovery would be investigated. This study will provide laboratory support for the field application.

1.2. STRUCTURE OF THIS THESIS

The first section introduces the background, objectives of this research and scope of the thesis. The second section presents the literature review of relevant research and field applications, including the application of polymers in oil fields, the use and challenges of polymers in heavy oil, and the mechanisms of low-salinity water and polymers. The third section introduces the experimental materials and equipment used in this paper. Then the experimental process is introduced, and the key points to be paid attention are explained. Section four and section five present the experimental results. In section four, three sandpack core flooding experiments prepared with silica sand are presented. Each experiment was targeted at different objectives of this study. The fifth section presents the results and analysis of formation sandpack core flooding experiments. This section was aimed at investigating the effect of polymer in heavy oil displacement under different conditions, which was more representative to the actual situation of oil field. The last section is the conclusions drawn from the experimental results.

2. LITERATURE REVIEW

This section comprehensively review the studies and field applications of polymer flooding in enhancing heavy oil recovery, including: 1) study of polymer flooding in improving heavy oil recovery efficiency; 2) research status of low salinity water flooding; and 3) research status of low salinity polymer flooding.

2.1. STUDY OF POLYMER FLOODING IN IMPROVING HEAVY OIL RECOVERY EFFICIENCY

The world's heavy oil resources are around 3396 billion barrels (Gao, 2011). With the depletion of light oil, the development of heavy oil fields is facing double technical and economic challenges. Due to severe viscous fingering, the recovery factor of heavy oil reservoirs is often less than 20% or even 10%. Thermal methods have been successfully applied in many heavy oil fields. However, ANS reservoirs are not suitable for thermal methods and will cause environmental damage (Gao, 2011). Water flooding is one of the essential technologies to improve oil recovery and belongs to the secondary oil recovery technology. But early water breakthrough hampers production and puts a heavy burden to the surface treatment facilities. These disadvantages make water injection development inefficient in heavy oil reservoirs. Considering the problems and challenges faced by water flooding in the application of heavy oil reservoirs, polymer flooding has become a process option with great potential for enhanced recovery than water flooding (Amirian et al., 2018). Seright (2010) discussed whether the flooding of polymer might function as an effective strategy for obtaining viscous oils from reservoirs without the application of thermal methods. The study highlights the screening criteria with regards to the implementation of polymer flooding. The combined screening criteria are enhanced oil recovery or enhanced oil recovery (EOR), suggesting that higher fuel costs increase horizontal well utilization, and the use of controlled injection techniques extends the significance of polymer flooding in areas with viscous oil. A number of studies on heavy oil recovery with polymer flooding have been carried out (Asghari and Nakutnyy, 2008). In terms of polymer flooding experiments for heavy oil with a viscosity of 1000~8400 mPa·s, only when the injected polymer solution exceeded a critical concentration, could the oil recovery factor be further increased based on water flooding, and the higher the reservoir permeability and the lower the injection rate, the higher the recovery efficiency by polymer flooding. Nuclear magnetic resonance imaging technology can be used to study the oil displacement mechanism. While increasing sweep efficiency, polymer flooding has also been reported to be able to increase displacement efficiency, thus increasing the oil recovery factor (Jiang et al., 1998; Xu et al., 2007; Asghari and Nakutnyy, 2008).

2.1.1. Polymer Flood Mechanism. The product of macroscopic displacement efficiency and microscopic displacement efficiency determines the overall displacement efficiency of the recovery process. Macro-displacement efficiency is a measure of the effectiveness of the displacement fluid in contact with the reservoir volume; micro-displacement efficiency is the effectiveness of the displacement fluid to trap oil on the pore scale through capillary forces. Therefore, in the polymer flooding process, any displacement mechanism that can improve the macroscale or microscale oil displacement efficiency is conducive to improving oil production (Romero-Zero'n, 2012).

Macroscopic displacement efficiency. Mobility is defined as the ratio of the relative permeability of a fluid (Such as water or oil) to the viscosity of the same fluid. The importance of controlling fluid flow to improve microscopic displacement efficiency has been recognized by many studies (Pitts et al., 1995). The process of adding polymer to the displacement phase reduces its mobility by thickening the water phase and significantly reducing the formation of viscous fingertips or channels. The mechanism that occurs simultaneously in the polymer flooding process is that the retention (adsorption and mechanical retention) of the polymer in the porous medium reduces the relative permeability of the displacement phase. Therefore, polymer flooding is very effective in improving volume sweep efficiency.

The mobility ratio is an important and useful parameter that can be used to quantify the flow contrast between displacing fluids. The mobility ratio of water flooding is given by the following equation (Pitts et al., 1995):

$$M = \frac{\lambda_w}{\lambda_0} = \frac{k_{rw} / \mu_w}{k_{ro} / \mu_o} \tag{2.1}$$

Where λ is fluid flow, kr is relative permeability, and μ is fluid viscosity. The subscripts w and o represent the water and oil phases, respectively.

Needham & Doe (1987) talked about the fractional flow of the polymer solution is one of the important mechanisms of polymer flooding. For homogeneous oil layers, under normal water injection conditions, because the viscosity of the injected water is usually lower than the viscosity of crude oil, the oil-water flow ratio is unreasonable during the flood process, which leads to the rapid rise of the water cut of the produced fluid. The actual oil displacement efficiency is far lower than the limit oil displacement efficiency. The result of injecting polymer into a reservoir can significantly improve the oil-water mobility ratio in the flooding process, thus, the rising rate of water cut in the production fluid is delayed, and the actual oil displacement efficiency is closer to the oil displacement efficiency limit, or even reaches the oil displacement limit. Under water flooding conditions, the flow rate of oil in the produced liquid after water breaks through the reservoir is:

$$f_0 = \frac{1}{1 + \mu_o k_w / \mu_w k_o} \tag{2.2}$$

Microscopic displacement efficiency. At present, certain progress has been made in the studies on microscopic oil displacement mechanism of polymer flooding. Wang et al. (2000) reported that the residual oil saturation (Sor) was reduced during polymer flooding and they attributed the Sor reduction to the viscoelasticity of the polymer solutions. The microscopic flooding experiments using glass models have provided some results in investigating polymer flooding mechanisms. Residual oil can be pulled into oil filaments by polyacrylamide due to its viscoelastic properties to produce the oil out (Xia et al., 2001). The greater the viscoelasticity is, the higher is the displacement efficiency. In the pore model with dead ends, the oil displacement efficiency of the dead-end of pore and throat is increased mainly relying on viscoelasticity eddy intensification (Yue et al., 2002). Wang et al. (2007, 2011) point out that when a fluid with elasticity flows through the dead end, in addition to the shear stress generated by the long molecular chain, normal stress between the oil and the polymer solution is also generated. As a result, the polymer exerts more force on the oil droplets, pulling them out of the dead end. The amount of residual oil extracted from the dead-end is proportional to the elasticity of the driving fluid. Non-elastic fluids (water and glycerin) can push the fluid forward, but cannot get oil out of the dead end. Clarke et al. (2016) investigated the effects of water phase flow fluctuations on trapped oil phases and their effects on fracture and desaturation. Figure 2.1 shows the effects of water phase (HPAM polymer solution) flow fluctuations on the trapped oil phase and the effects on rupture and desaturation were studied, illustrates the movement of the meniscus because the expected fluctuations in the pressure of the water phase are caused by fluctuations in the flow of the water phase. Micro-model experiments show that HPAM solutions that flow at greater than critical velocity exhibit strong flow fluctuations that are consistent with significant flow thickening. Although apparent flow thickening can also be attributed to elongational viscosity, it is clear that flow fluctuations also exist.

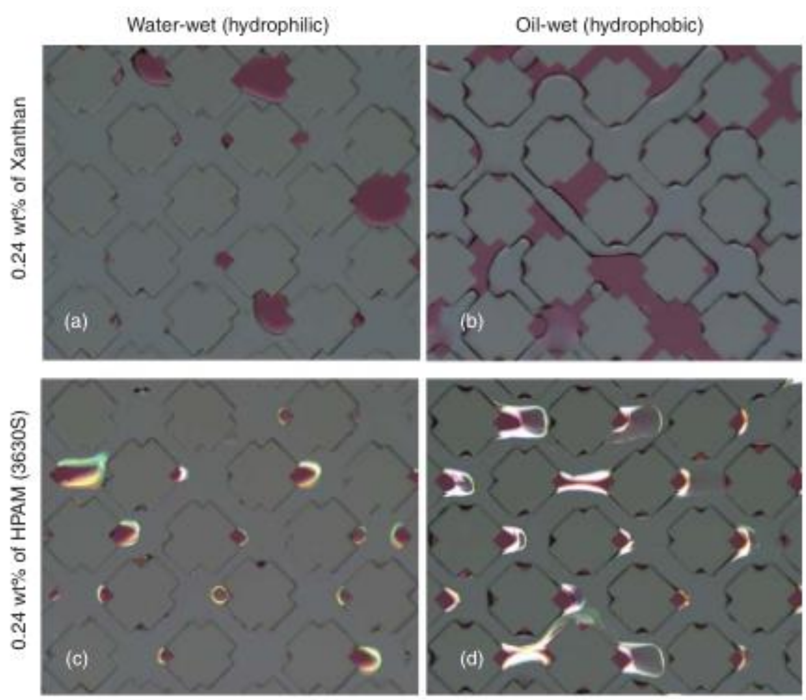

Figure 2.1 The presence of bright halos on each drop indicates moving menisci. (From Clarke et al., 2016)

Cheng and Cao (2010) studied the fluidity of a polymer solution through a porous medium from three stages. They established a pressure drop for the viscosity drop and the elasticity drop, respectively, to determine the nature of the viscoelastic fluid, considering the polymer flow characteristics and the characteristics of the porous medium。The model was validated with experimental data from core displacement. The rheological behavior of polymer solution in porous media was accurately characterized, including two stages: shear thinning and shear thickening.

2.1.2. Lab Result and Field Results on Heavy Oil Reservoirs. Wang & Dong (2009) studied the relationship between the effective viscosity of polymer solution and recovery factor during heavy oil polymer flooding in the laboratory. Twenty-eight sandpack core flooding experiments were performed on heavy oil with a viscosity of 430-5500 mPa. The results show that there is an optimized range of polymer viscosity where the oil recovery improvement rapidly increases with the polymer effective viscosity. Outside this range, the increase in recovery is small with increasing effective viscosity. At the same time, it was also found that the minimum and maximum values of effective viscosity increased with the increase of the viscosity of the crude oil, and the two had a linear relationship in the double logarithmic way (Figure 2.2). It is also found that the earlier the polymer flooding is applied, the lower the polymer viscosity required to produce a significant increase in the recovery factor. The displacement results of heterogeneous sandpacks show that due to the heterogeneity of the porous medium, the polymer recovery is greatly reduced, and a polymer solution with a high viscosity is required to achieve the effect in the homogeneous sandpacks. The applicability of polymer flooding in specific reservoirs depends on different parameters, such as: crude oil viscosity, oil saturation, polymer molecule relative to rock pore size, polymer molecule stability in the reservoir environment, and reservoir heterogeneity Quality, well spacing and injection flow. Although there have been some pilot and full-field polymer flooding of polymer flooding in light oil reservoirs, there are few examples of polymer flooding evaluation and implementation in heavy oil reservoirs

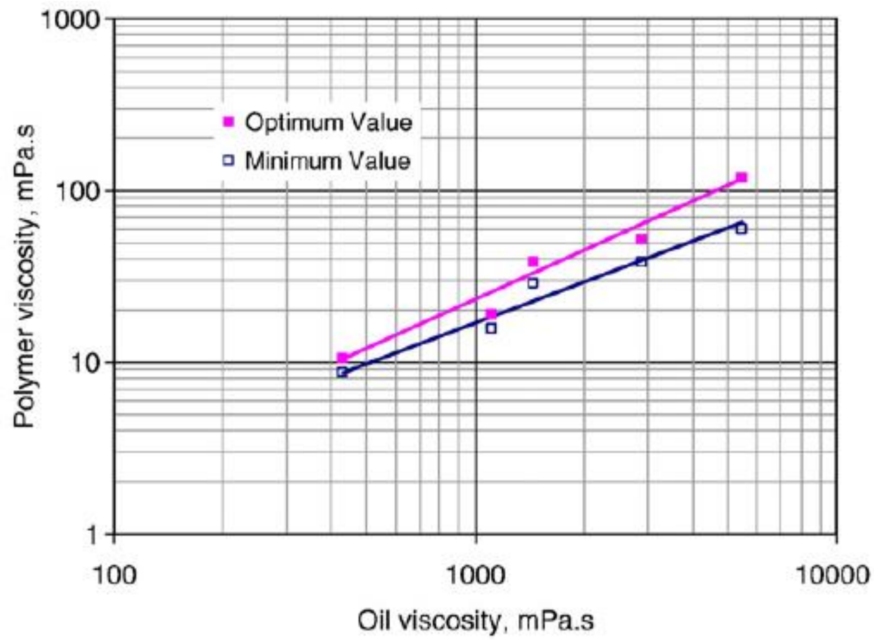

Figure 2.2 Change in optimum value and minimum value of the effective viscosity of polymer solution with oil viscosity. (From Wang & Dong, 2009)

Wassmuth et al. (2007) conducted laboratory tests, and the results showed that injecting a viscous polymer solution into a heavy oil-saturated core could expedite displacement. When the core is initially injected with at least one pore volume of water, all three polymer floods with different oil viscosities (280 to 1600 cp) can increase the recovery factor (16% to 23% OOIP). Polymer flooding would shift the water fractional flow curve towards right, resulting in a more piston-like displacement. And the favorable polymer flooding development scheme proposed has more than doubled the recovery factor of water flooding under the economic limit. Even for unfavorable oilfield situations where heterogeneities are present, polymer flooding technology is also an essential consideration for improving heavy oil recovery.

Asghari et al. (2008) conducted polymer flood experiments on heavy oils with an oil sample viscosity up to 8400 mPa s, and investigated the enhancement of heavy oil recovery by HPAM solutions at concentrations of 500, 1000, 5000, and 10,000 mg/L. The results shown that when HPAM solution concentration is higher than 5000mg/L, the recovery factor is increased by more than 10% OOIP.

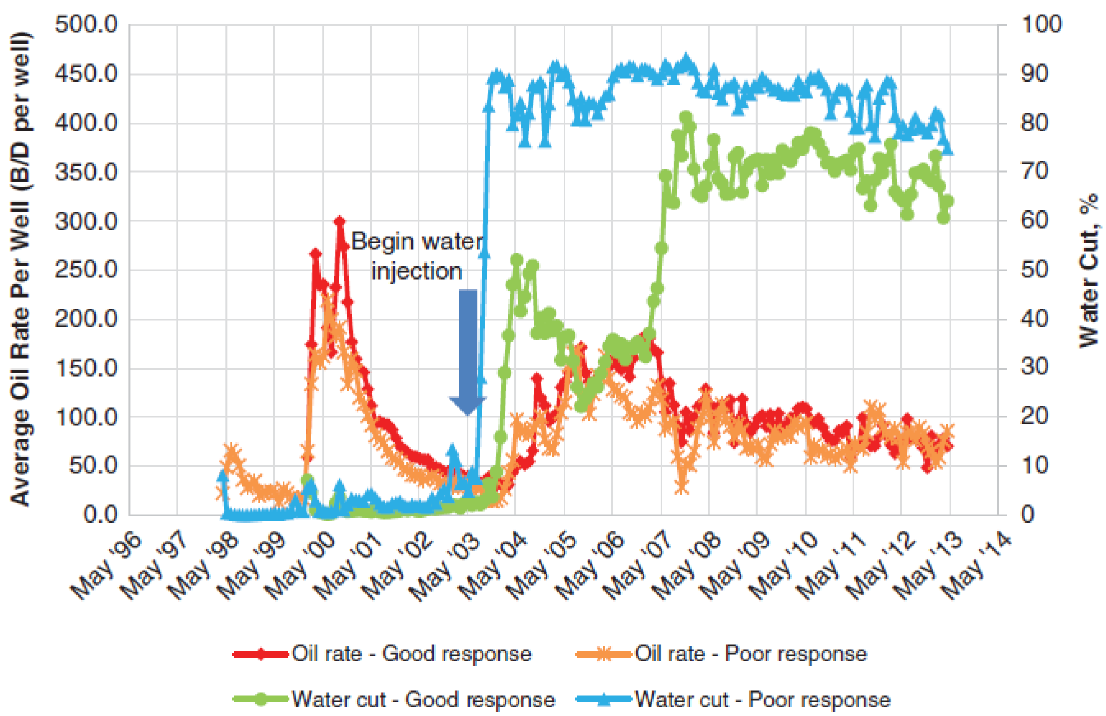

Figure 2.3 Waterflood production plot from Delamaide et al. (2013)

Delamaide et al. (2013) described the results of the polymer injection in the Pelican Lake field in Western Canada (Figure 2.3). The implementation of the polymer flooding began in the early 2000s and has resulted in a significant increase in recovery (5-10% of OOIP). By the middle of 2000s, polymer flooding tests had been implemented and proved successful, resulting in an incremental oil recovery of over 25% of OOIP, while maintaining a relatively low water cut. The success of the pilot encouraged the extension of the polymer flooding over the entire Pelican Lake field. The important lesson from this experience is that polymer flooding does not need to target the unit mobility ratio for heavy oil, but should compromise between mobility ratio and injection capacity to optimize the project.

2.1.3. Challenges of Polymer Flooding in Heavy Oil Reservoirs. According to the polymer flooding theory, the viscosity of polymer solution could be increased through polymer molecular modification (Zhang, 2013), increasing the concentration of polymer solution (Liu et al., 2006) or molecular weight of polymer solution (Hester et al., 1994), so as to enhance the polymer flooding mobility control ability. However, simply increasing the viscosity of the polymer solution will increase its flow resistance in the porous medium, therefore, it also poses higher difficulties in the production technology of polymer for flooding applications. Thus further increasing the cost (Wang et al., 2010). Meanwhile, the higher viscosity of the polymer solution requires higher requirements for injection system. While the polymer solution flowing through the blasthole, compaction zone and near-wellbore zone of the perforated interval, the shear effect causes the viscosity and other properties of the polymer solution to decrease greatly (Wang et al., 2010). In addition, thermal degradation (Du and Guan, 2004) and mineralization of injected water mainly Ca2+ and Mg^{2+} (Jamaloei et al., 2012) will also make the viscosity of polymer solution unable to reach the design and reservoir requirements. Therefore, it is the most effective and reliable tactic to improve polymer flooding effect by establishing effective residual resistance coefficient in the main flow area of heavy oil reservoir with displacement agent and reducing the cross-flow of polymer molecular.

In order to ensure that polymer flooding can be carried out successfully, the residual resistance coefficient of conventional polymer flooding is generally 1 to 3. Although the polymer solution has better injection capacity, it is unable to establish an effective flow resistance in the mainstream line, leading to fluid channeling of polymer solution, short flood-response time, and reduced polymer flooding effect. In particular, in high permeability heterogeneous reservoir, moderate adsorption of polymer molecules and rock surface is the basis for polymer to establish residual resistance coefficient. On the one hand, too strong adsorption should be avoided, otherwise, polymer solution will suffer great loss in the near well zone; on the other hand, too weak adsorption should be avoided. (Zhang and Liu, 2011).

It can be seen from the above two aspects that in the development process of polymer flooding for heavy oil reservoirs, although various measures have been taken such as increasing solution viscosity and improving the residual resistance coefficient, there are still great differences in longitudinal and plane mobility in the reservoirs as well as serious viscous fingering under the influence of oil-water viscosity difference and heterogeneity. Early polymer breakthrough is a major concern for the success of a polymer flooding project because it will significantly reduce the efficiency of polymer flooding. This problem could be much worse for heavy oil reservoirs.

2.2. RESEARCH STATUS OF LOW SALINITY WATER FLOODING

As ANS reservoir injected low salinity water, some low salinity water research has been shown in this section.

McGuire et al. (2005) conducted a study in Alaska and found that due to LSW injection, the remaining oil saturation was significantly reduced by 6-12% of the original crude oil (OOIP). Under LSW, Lager et al. (2008) the oil production on the Alaska North Slope reservoir doubled, the water-oil ratio (WOR) decreased significantly, and the remaining oil saturation decreased from 30% to 20%. In general, various mechanisms have been proposed in the literature to explain the additional oil recovery from low salt injection.

However, LSW is an immature technology for enhanced oil recovery and has great potential for enhanced oil recovery (Katende & Sagala, 2019). It has been confirmed through various laboratory studies and field applications. Different researchers have proposed several recovery mechanisms. However, there is currently no consensus on which mechanisms play a leading role in improving the recovery factor in the process of water injection with low salinity (Katende & Sagala, 2019). The following part introduces the article that first proposed the mechanism.

In the petroleum production industry, salinity and ionic composition of injected water are not the main problems in the petroleum production industry, except possibly taking into account of the reservoir (as well as optimizing surfactant flooding performance). However, it has been known for decades that the ionic strength of fluids flowing in porous media does affect the measured permeability (Schleidegger, 1974). As a rule, the most recently available water supply has been used for water flooding, and offshore applications generally mean seawater and laboratory experiments for offshore applications are often conducted using (synthetic) reservoir brine or seawater.

In the 1990s, Norman Moreau and colleagues at the University of Wyoming published a core flood report, which pointed out that injection of low-salinity water resulted in increased oil production compared with injection of high-salinity (seawater) water Tang and Morrow, (1999). Tang and Morrow (1999) believed that in theory, the injected water with low salinity would cause clay and silt in the stratum to fall off, and these particles would move along the high permeability path. Having been left in smaller pore space, the particles would force the injected water to move to areas with lower permeability. Tang and morrow observed that for different sandstone cores, with the decrease of the degree of mineralization of the injected water, there would be some particles (mainly kaolin debris) released from the rock. Since then, many experiments have been carried out, showing improved recovery and some without additional improvement Zhang et al., (2007). Others show effects in secondary and tertiary modes, and some only in secondary mode (Rivet et al., 2010).

As a result, the primary evidence of low salinity comes from core flood testing, and the uncertainty and reliability of the data obtained have not received a certain degree of attention. Field evidence is now beginning to be collected from single-well tests, using reactive tracer tests to assess saturation changes, as well as field pilots. Table 2.1 summarizes the mechanisms that have been suggested. These have been divided into types in the table according to which flow parameter they are addressing.

Table 2.1 Overview of Suggested Low Salinity Water Flooding Mechanisms

Type	Mechanism	Explanation	Main reference
Pressure/ permeability	Osmosis	Clay distributed at different salinities produces additional pressure, which increases water drive.	Buckley, (2009)
	Clay particle (fines) movement	Due to the expansion of the electrical double layers (which may also be ion exchange), clay particles and other mixed wet fines are removed from the rock surface, leaving a water-wet point in low salinity conditions. The penalty for migration may block the narrow pore throat and cause microscopic transfer of the injected water.	Tang and Morrow (1999)
IFT reduction	Alkaline flooding behavior	PH rises in low-salinity floods high enough to make certain components of oil saponified. This reduces the interfacial tension between water and oil (similar to alkaline flooding).	Buckley, (2009)
	"Salt-in" effect	Charged oil components on clay surface are easier to decompose and dissolve in water phase. The salt effect. Loose particles reduce the interfacial tension between water and oil, like a surfactant flood.	Austad, (2008)
Wettability change	Multicomponent Ion Exchange (MIE)	Due to expansion of the electric double layer and cation exchange capacity of the clay complex, bound charged organic components of the oil are substituted by Ca^{2+} leading to an increase in the water wetness of the formation.	Lager, (2006-8); Ligthelm, (2009)
	pH driven	The cation exchange capacity of the clays is triggered by near surface pH changes brought about by protons substituting Ca^{2+} on the clay surfaces in low salinity water flooding.	Austad et al., (2010)

2.3. RESEARCH STATUS OF LOW SALINITY POLYMER FLOODING

Polymer flooding and low salinity flooding are two technologies that can improve the oil recovery factor and are relatively easy to apply in many oil fields. Polymer flooding is a well-known method to increase oil recovery. It improves the sweep efficiency by thickening water. The application range of polymer flooding is mainly limited by the reservoir temperature and the salinity and hardness of the supplemental brine due to chemical degradation of the polymer. In contrast, the application of low-salt flooding depends only on the availability or selectivity of producing low salinity injection brines. The benefits of reservoir development depend on the combined effects of reservoir mineralogy, reservoir brine, and crude oil composition. By combining these two technologies, injecting a low salinity polymer solution, the interests of both parts can be expanded. First, adding polymers to low-salinity floods can increase the sweeping efficiency and mobilize some of the oil separated by low-salinity brines, otherwise these oils will be trapped Shaker and Skauge (2013). Also, by supplementing the polymer with a low salinity brine, the low salinity effect can increase polymer flooding recovery by altering the wettability of the rock surface and releasing additional oil. Alzayer and Sohrabi (2013) simulated the performance of low salinity water and polymers with several injection schemes involving 80 cP crude oil viscosity under heavy oil reservoir conditions at a depth of 3000 feet. Low salinity water flooding and polymer flooding were used to predict the recovery of heavy oil. It was discussed that low salinity water flooding could advance the well to maximize contact with the reservoir. The regional model was used to evaluate several solutions that combine low salinity water flooding, polymer flooding, and well deployment. The results presented in the article show that the combination of low salinity water flooding and polymer flooding can increase the final recovery factor by about 10% of the original oil in place. In contrast, polymer flooding would provide a similar increase, but with better effectiveness. The main reason for the high efficiency of polymer flooding is that the mobility ratio has been adjusted to make the displacement process more like a piston. The combination of low salinity water flooding and polymer flooding leads to oil recovery of 7.5% to 10% of the original oil in place. The results would need to be verified experimentally, laboratory experiments, and further optimization of this research would increase its accuracy and expand its applicability. For high permeability and low viscosity heavy oil reservoirs, the author suggests investigating the applicability of polymer flooding as a secondary recovery method, followed by low salinity water flooding as a tertiary recovery method. Previous wells have been suggested to increase reservoir contact and recovery. The simulation results are shown in the Figure 2.4.

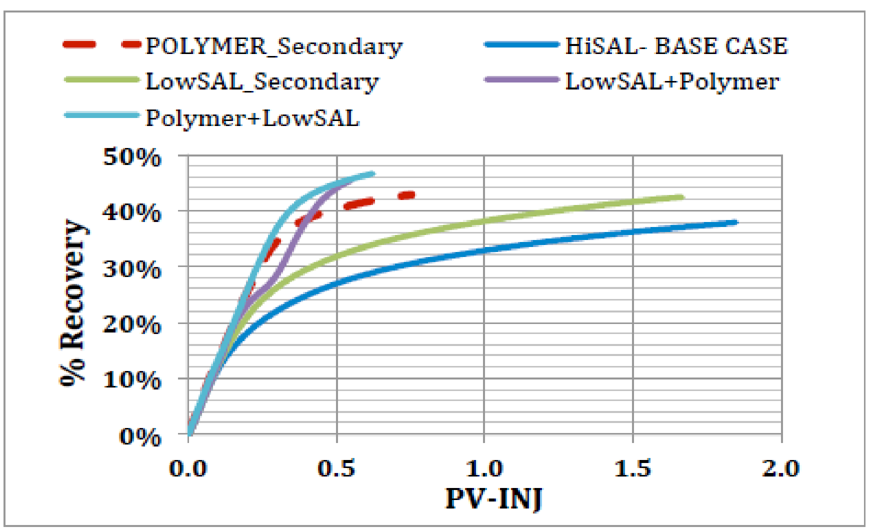

Figure 2.4 Comparing low salinity polymer with different configuration to base case (From Alzayer and Sohrabi, 2013)

A feasibility study experiment Vermolen et al. (2014) of low-salinity polymers was carried out to pre-select the polymer types, brine composition, and polymer concentration that might be suitable. In the core flooding test, the effects of cation exchange, clay swelling, adsorption, and hydrodynamic acceleration were tested and quantified, and the effluent was analyzed in detail. In the same experiment, the in situ rheology of the polymer was measured. Finally, through a series of core displacement tests, measurement to improve the recovery factor were determined. The results show that polymer flooding with brine with low salinity in high salinity reservoirs has many advantages over traditional polymer flooding. With residual oil saturation, core flooding needs to be tested for risks of cation exchange and clay swelling, as core flooding in bare core (no oil) cores may overestimate the risks. When polymers are added to low-salinity slugs, the divalent cation fraction decreases less, thereby reducing the risk of clay swelling. Polymer adsorption has a buffering effect on polymer flooding, but at the same time, it will also delay oil recovery and adversely affect the economic benefits of polymer flooding. If the use of low salinity polymers results in delayed oil recovery, the economic viability of the process can be improved by optimizing the stability of the injected brine and / or the polymer concentration.

Skauge and Shiran (2013).carried out core flooding experiments to study the recovery improvement potential of low-salinity polymer flooding on porous media with different wettability and permeability. The results were shown in Table 2.2. Studies have shown that the low salinity water flooding in the tertiary oil recovery mode has little effect on the extra recovery of core plugs. Compared with the high salinity flooding, the recovery factor of crude oil was significantly improved in the model of low salinity flooding of Berea samples. Similar to the low salinity effect, the secondary LS has a better response to polymer flooding. Although from the perspective of capillary desaturation, the polymer improves crude oil recovery, it is still not enough to mobilize the capillary trap oil. Therefore, the additional oil recovery can be attributed to the improvement of microscopic sweep efficiency or the combined effect of low salinity oil flows.

Table 2.2 Improved oil recovery of low salinity polymer flooding (from Skauge and Shiran, 2013)

Core ID	Porosity (%)	RF (%OOIP)	%Sor Reduction After LSP
S3-S4	19.13	69.1	13
S5-S8	18.51	70.1	16
S6-S7	18.78	89.8	53
S9-S10	19.28	51	0
B2-B4	25.60	78.3	39
B8-B9	23.99	56.2	9
B10-B11	22.81	59	7

3. EXPERIMENT METHOD

3.1. EXPERIMENT MATERIALS

3.1.1. Heavy Oil Sample. The heavy crude oil sample was provided by Hilcorp LLC, sampled from the wellhead of Well # B-28 at the Milne Point Unit. The viscosity measured at reservoir temperature (71 °F) was 202 centipoises (cp) and the density was 0.940 g/cm^3 (19 °API).

3.1.2. Water Sample. The synthetic formation brine (SFB) and synthetic injection brine (SIB) were prepared in lab according to the water composition analysis of the formation water and injection source water at the target oil field (Milne Point Unit) on the Alaska North Slope. The salinity of the SFB and SIB were 27,500 ppm and 2498 ppm, respectively. The detailed composition was shown in Table 3.1. The concentrations of Ca^{2+}, Mg^{2+}, and Na^+ of SFB were much higher compared with the SIB. The water would be filtered with a filteration apparatus using Millipore™ membrane.

The SFB was used to saturate the sandpack cores at the very beginning of the coreflooding experiments. It was also used for initial water flooding to establish a secondary recovery condition. This flooding process was regarded as the normal salinity water flooding throughout this thesis as the salinity was the same as the formation water. The SFB was also used to prepare normal salinity polymer solutions for polymer flooding. The SIB, considering its low salinity nature, was regarded as low salinity water (LSW) throughout the thesis. The SIB was used in low salinity waterflooding (LSWF) and in preparing low salinity polymer solutions. Softened low salinity water (SLSW) was prepared by removing the divalent ions in the SIB. In practice, the SLSW was prepared by replacing the calcium chloride and magnesium chloride with twice molar concentration of sodium chloride. Also, ultra-low salinity water (ULSW) was prepared by diluting the SIB ten times.

Table 3.1 Information of water samples

Name	Description	Density (g/ml)	Salinity (ppm)	Composition (ppm)
SFB (normal salinity water)	Synthetic formation brine	1.062	27500	Na^+: 10086.0 K^+: 80.2 Ca^{2+}: 218.5 Mg^{2+}: 281.6 Cl^-: 16834.4
SIB (LSW)	Synthetic injection brine	1.030	2498	Na^+: 859.5 K^+: 4.1 Ca^{2+}: 97.9 Mg^{2+}: 8.7 Cl^-: 1527.6

3.1.3. Sand Sample. The Silica sand sample was prepared in the lab and mesh size was 50-60 mesh. The formation sand was sampled from Milne Point NB formation, provided by the Hilcorp LLC. The received formation sand was a mixture of formation sand and reservoir fluid (mainly visocus oil). Handling of the formation sand sample was detailed in Section 5.

3.1.4. Polymer Sample. The polymer used was Flopaam 3630 (from SNF), which was the same as the one used in the target oil field. The polymer had a molecular weight of about 18 million daltons and a hydrolysis degree of around 30%. The polymer was originally in powder form and was used as received. The desired amount of polymer powder was slowly added to the brine that was being stirred with a magnetic stirring bar.

The solution was stirred for about 48 hours at 300 rpm at room temperature. The after being visually homogeneous (no “fish eyes” or aggregates), the viscosity of the solution would be measured to check whether the desired viscosity was achieved (45 cp at 71 °F, used in target oil field). The solution would be adjusted to the target viscosity by adding polymer or water. The normal salinity polymer fluid was prepared with filtrated SFB, and the viscosity was 45 cP at 7.3 s^{-1} at 71 °F. The low salinity polymer solution was prepared with filtrated SIB and the viscosity was also 45cP at the same condition. The polymer solution was also filtered with a filteration apparatus using Millipore™ membrane before carrying out polymer flooding experiments.

3.1.5. Tracer Sample. The Potassium Iodide (⩾99%, Sigma-Aldrich) was used as a tracer which was added in the SFB at the concentration of 40 ppm to measure the homogeneity of the sandpack cores prepared in the experiments. The tracer concentration was measured with a UV-vis spectrophotometer (Shimadzu UVmini-1240 UV-vis spectrophotometer). The tracer test procedure would be described in detail in Section 5.

3.2. EXPERIMENT EQUIPMENT

3.2.1. Sandpack Tube. Figure 3.1 shows the sandpack tube to prepare sandpack cores with a dimension of 2.54 cm × 20.4 cm. The main body could stand the pressure as 4600 psi. There were slots on the inlet plug. The slots were connected with the entrance. Also, a piece of stainless steel screen was added between the inlet plug and the sand. The slots, together with the screen distributor make the injected fluid uniformly enter the sand face to ensure a good injection profile. A piece of stainless steel screen was attached at the outlet end plug to prevent sand from being flushed out of the sandpack tube.

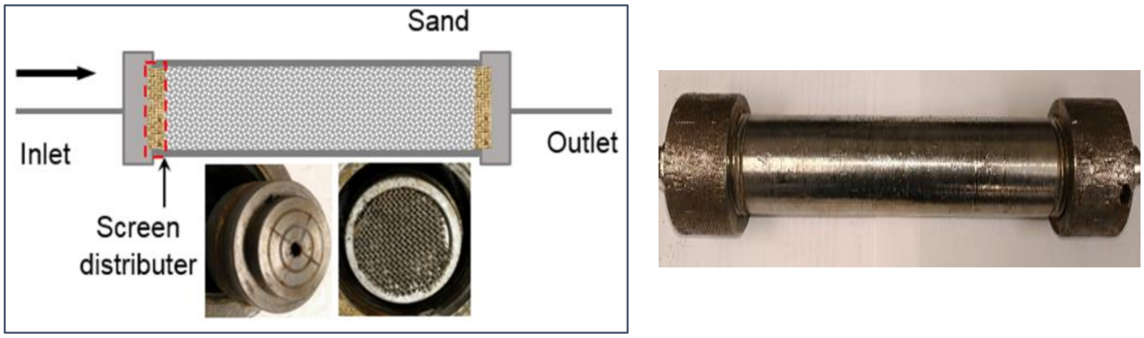

Figure 3.1 The sandpack model

3.2.2. Membrane Filter. The filtration setup is shown in Figure 3.2. The fluid to be filtered (e.g. formation water) was poured into the bucket and then filtered under constant pressure 10 psi provided by a nitrogen gas cylinder. The filtered solution flowed into the measuring cup and was stored for further use. In the experiments, the membranes with poresizes of 1.2 μm were used.

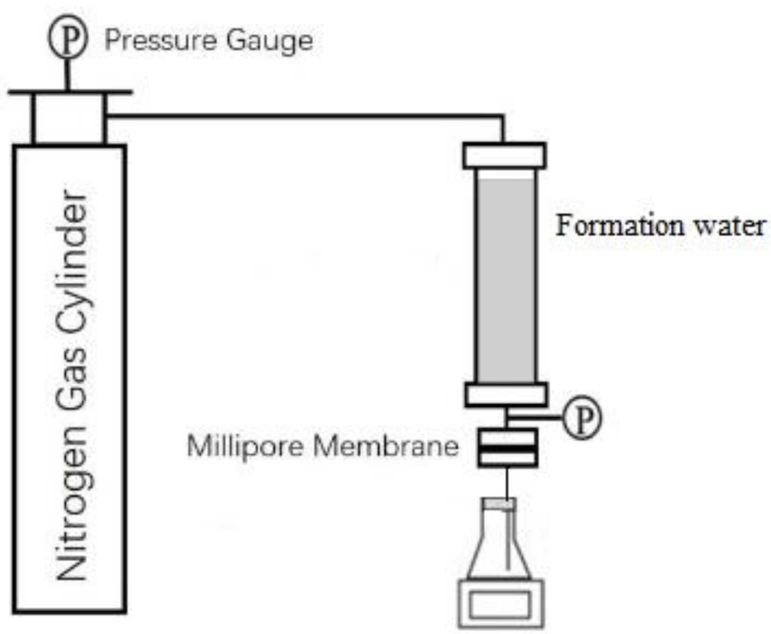

Figure 3.2 The filtration setup

3.2.3. Brookfield DV3T Rheometer. A Brookfield DV3T viscometer was used to measure the viscosity of crude oil, brine, and polymer solutions. The viscometer is shown in Figure 3.3. For the polymer solutions, the viscosity was measured in a wide range of shear rate of 0.5-200 s^{-1}. For the crude oil sample, due to the relatively high viscosity, the SC-34 spindle was used in the test. For the brine and polymer solutions, due to the relatively low viscosity value, a ULA spindle was used to perform the tests. Figure 3.4 shows the viscosities of the two polymer solutions used in this study. The viscosities of the two polymers were close to each other and both polymer solutions exhibited shear-thinning behavior.

Figure 3.3 The Brookfield DV3T viscometer

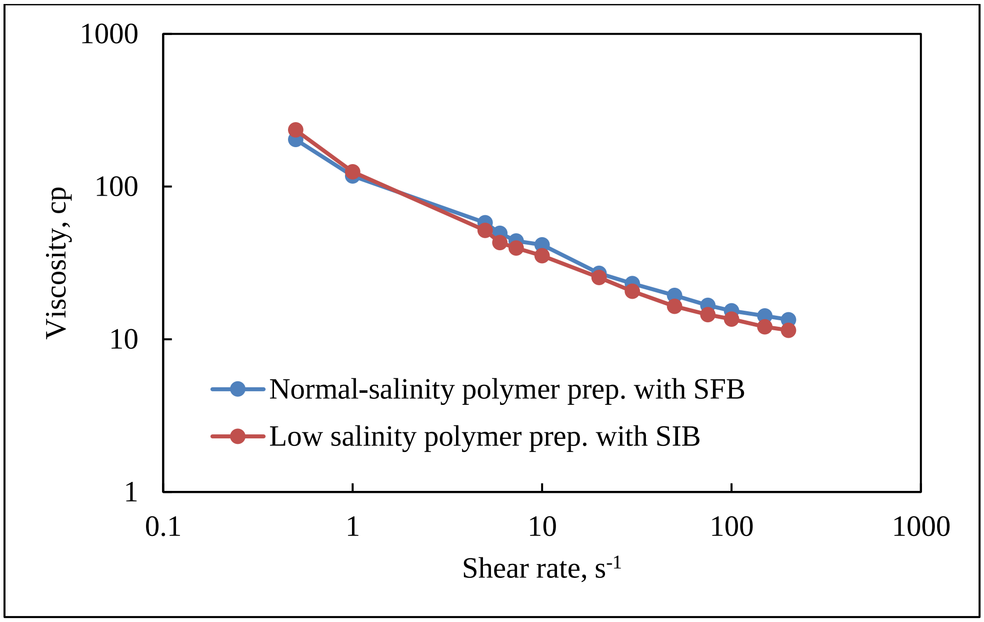

Figure 3.4 Viscosities of the polymer solutions

3.2.4. Shimadzu UVmini-1240 UV–vis Spectrophotometer. The Shimadzu UVmini-1240 UV–vis spectrophotometer shown in Figure 3.5 was used to measure the tracer concentration. The absorbance in the range of 190 to 1100 nm was scanned and the absorbance at the peak of 225 nm was proportional to the tracer concentration.

Figure 3.5 The Shimadzu UVmini-1240 UV–vis spectrophotometer

3.3. SANDPACK CORE FLOODING EXPERIMENT PROCEDURE

The experiment setup used for coreflooding was shown in Figure 3.6. The experiment procedure was briefly summarized below. For convenience, the procedure adopted in performing the base case of silica sandpack experiments was taken as an example to describe the experiment process. The basic processes of the other sandpack core flooding experiments were similar to this experiment. Special considerations would be pointed out in presenting and discussing the experimental results.

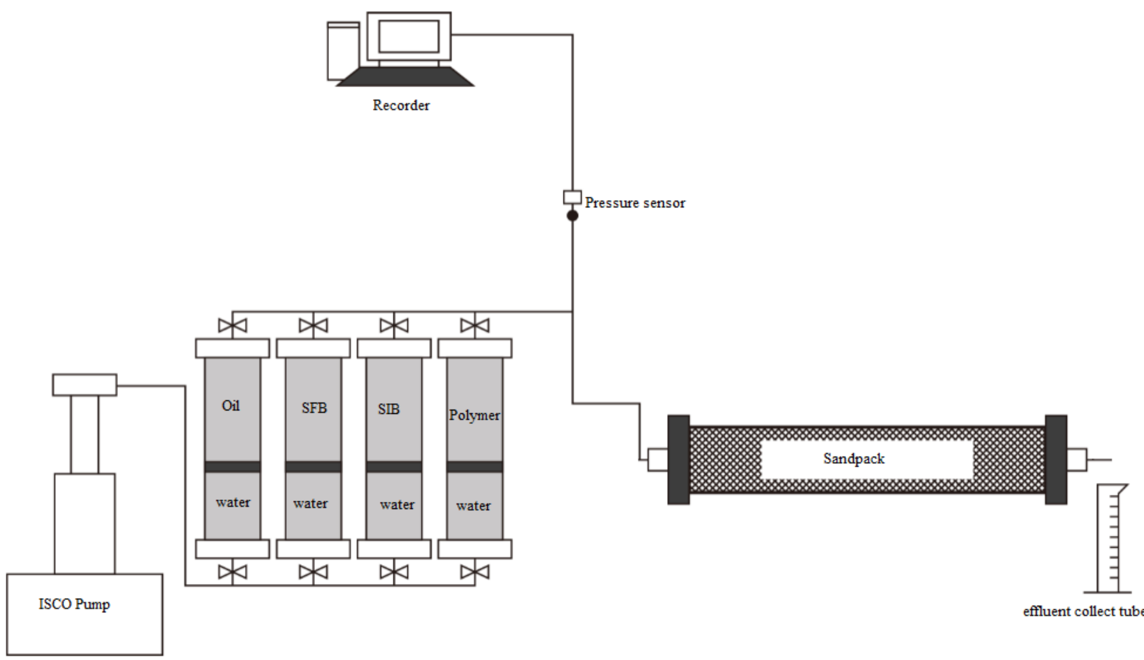

Figure 3.6 Experiment setup for sandpack core flooding test

The experiment procedure is summarized as below:

(1) Pack the sandpack;

(2) Dry the sandpack at 80 °C for 48 hours and measure the dry weight. Put the sandpack in the vacuum pump and vacuum for 6 hours;

(3) Saturate the sandpack with synthetic formation brine. More than 5 PVs of brine was injected to saturate the sandpack after vacuum. The weight was measured. The pore volume was calculated with dry weight, wet weight and brine density.

(4) Measure the absolute permeability with synthetic formation brine. Four injection rates, 0.5, 1, 1.5, 2 mL/min, were used to measure the absolute permeability. At each injection rate, stable pressure was reached. The absolute permeability was calculated using Darcy's equation.

(5) Saturate with crude oil (B-28). 5 PV crude oil was injected into the sandpack at 0.2 mL/min.

(6) Age the sandpack for 4 days at 70 ℉ (reservoir temperature).

(7) WF: 0.1 mL/min until water cut leveled at 100%.

(8) LSWF: 0.1 mL/min until no was oil produced.

(9) ULSWF: 0.1 mL/min until no oil was produced.

(10) PF: 0.1 mL/min until no oil was produced.

4. SILICA SANDPACK RESULTS

This section would present and discuss the results of experiments performed with silica sandpacks that had similar mineralogy with reservoir sand. The silica sand was chosen to run the first set of experiments due to the limited amount of reservoir sand samples. These experiments were aimed at investigation of the effect of salinity on polymer flooding performance and identification of key factors that governing the oil recovery performance. After gaining primary experience and understanding of polymer flooding in recovering heavy oil, experiments using reservoir sand materials would be carried out to test the reproducibility of the observations made in this section and further explore the favorable conditions for polymer flooding on the ANS. The results would be presented and discussed in the next section.

Table 4.1 Properties of silica sandpack experiments

Sandpack #	d, cm	L, cm	A, cm^2	PV, cm^3	porosity	K, md	Flooding process
1	2.54	20.40	5.07	37.57	0.377	820	(1) WF (2) LSWF (3) ULSWF (4) PF
2	2.54	20.40	5.07	23.92	0.231	930	(1) WF (2) LSWF (3) SLSWF (4) LSPF
3 (secondary model)	2.54	20.40	5.07	34.70	0.336	840	(1) LSWF (2) LSPF (3) LSWF

Three sandpack flooding tests have down in this part by using different salinity water and polymer. Table 4.1.shows the properties of each sandpack.

4.1. BASE CASE STUDY EXPERIMENT #1

The first sandpack coreflooding experiment was a base case study carried out to investigate the general performance of waterflooding and polymer flooding in recovering the Schrader Bluff heavy oil at the Milne Point Unit on the Alaska North Slope. This experiment provides a benchmark for further investigation of the effect of salinity, injection sequence and recovery mode on the oil recovery performance.

After establishing the initial water saturation condition, the sandpack was first flooded with normal-salinity water. The salinity of the water was the same as the Schrader Bluff formation water (~27,400 ppm) to avoid the possible impact of ion change on the normal waterflooding performance. The injection rate was set at 0.1 ml/min. The flooding process was continued until the water cut reached 98% which was usually adopted as an economic development limit. The oil recovery performance and water cut behavior are shown in Figures 4.1 and 4.2. The water breakthrough occurred at 0.29 PVs of water injection. As more water was injected, the water cut rose rapidly. The water cut quickly increased to over 80% after the water breakthrough at approximately 0.7 PVs of water injection. Meanwhile, the oil recovery factor reached 40% of OOIP. The results indicated that the waterflood process was unstable due to the high viscosity of crude oil. The mobility ratio was much higher than one. Viscous fingering was expected to occur, which was responsible for the unsteady displacement of a viscous fluid by a less viscous fluid. (Fanchi, 2005). As the flooding process continued, the water cut climbed up to 98%

after 2.1 PVs more water was injected into the sandpack, and another ~16% more oil was recovered. In total, the oil recovery from the 2.8 PVs of the first normal salinity water flooding turned out to be 55.97% of OOIP.

Low salinity waterflood (LSWF) was performed to investigate whether low salinity waterflood which has been widely reported beneficial for improving oil recovery (ref) could reduce the water cut and recover more oil compared with normal salinity water. The salinity of the LSW was 2500ppm, which was the same as the injection water used in a pilot project at the Milne Point Unit on the Alaska North Slope. The oil recovery and water cut results are also shown in Figures 4.1 and 4.2. It was observed that the water cut decreased to from 98% to 91.5% after injecting 0.81 PVs of LSW, and considerable incremental oil was achieved. During the first pore volume of LSWF, 4.23% of OOIP more oil was recovered, increasing the oil recovery factor further to 60.20%. After 1.31 PVs of LSW injection, the water cut rose to 99% and the oil production was negligible afterwards. In total around 3.3 PVs of LSW was injected and only water was produced at the end of this flooding process. The oil recovery factor reached 60.52% after the first normal salinity water flooding and the subsequent low salinity water flooding.

Whether further lowering the salinity of the injected water can improve the oil recovery efficiency? The ultra-low salinity waterflood (ULSWF) was conducted after the LSWF. The ultra-low salinity water (ULSW) was obtained by diluting the SIB with DI water by 10 times. Thus the ULSW had a salinity of about 250 ppm. It was observed that the water cut only showed a noticeable, but very short-period reduction at the very beginning of the ULSWF. The short-period water cut reduction was more likely a result of pressure disturbance caused by the operation of switching LSWF to ULSWF, rather than the EOR benefit of ULSWF. Even after 5 PVs of ULSWF, the oil recovery improvement was still unsatisfying, which was only around 2% (including over 1% observed at the very beginning). The results indicate that the effect of continuously reducing the water salinity beyond the low salinity injection water on improving the recovery factor was limited.

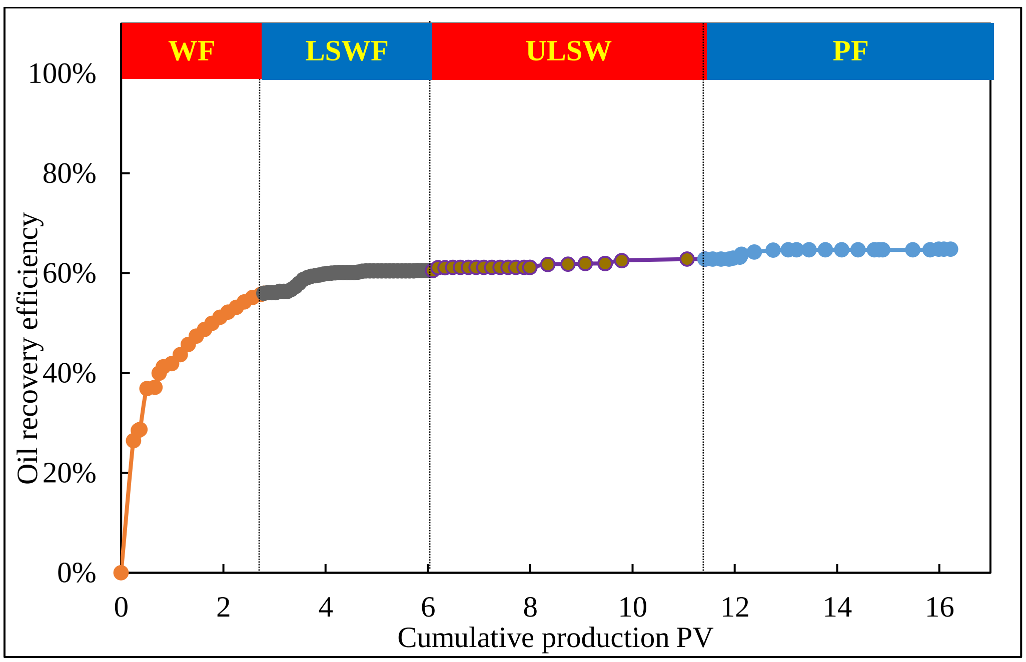

Figure 4.1 The oil recovery performance (Exp. #1)

Polymer flooding was performed after the ULSWF. The viscosity of the polymer was 45 cP. The polymer was prepared with SFB, and thus it had the same salinity as the formation water. The flow rate was still set at 0.1 ml/min. As shown in Figures 4.1 and 4.2, the water cut was decreased to as low as 80% after injecting 0.72 PVs of polymer, and the oil recovery efficiency was further increased to 64.82%. The oil recovery improvement was ascribed to the reduced mobility ratio of the polymer against the oil phase. The displacement process became more stable so the viscous fingering was weakened. The oil previously passed by water was swept by the polymer and displaced out, thus more oil was recovered.

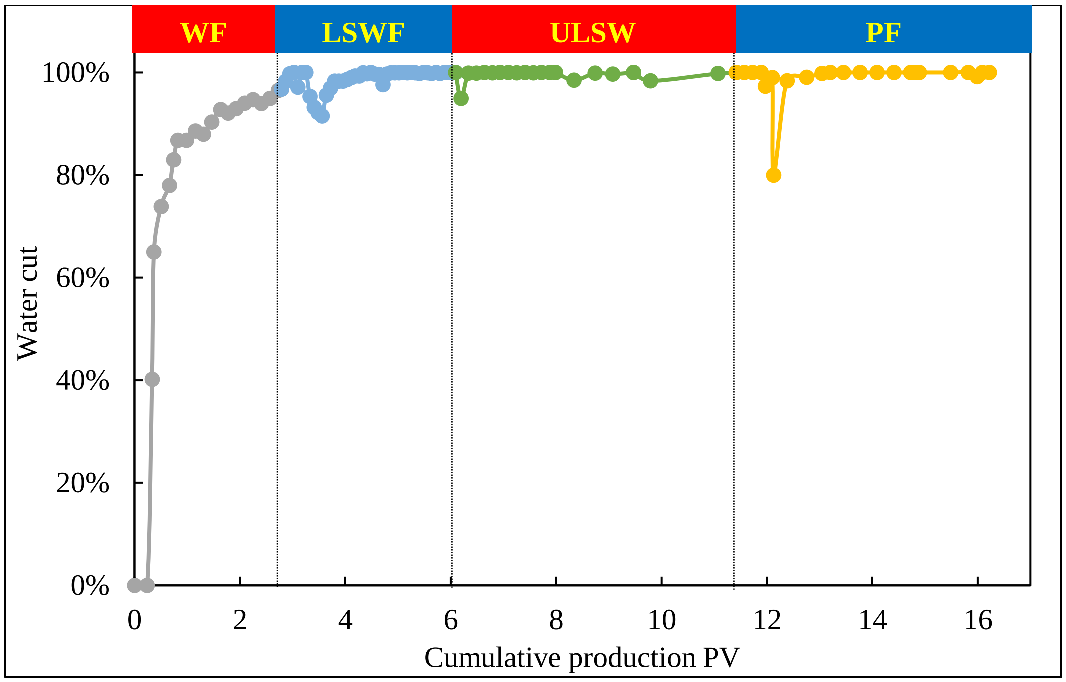

Figure 4.2 The water cut behavior (Exp. #1)

The oil saturation in the sand pack was reduced accordingly during the flooding process, as shown in Figure 4.3. In the normal salinity waterflooding process, the oil saturation was reduced from 0.9 (initial oil saturation) to 0.44, and in the following LSWF, the oil saturation was further reduced to 0.345. A slight reduction of oil saturation was observed during the following ULSWF. Interestingly, the oil saturation was further decreased to 0.281 after a total of 13 PVs of extensive waterflooding (including WF, LSWF and ULSWF).

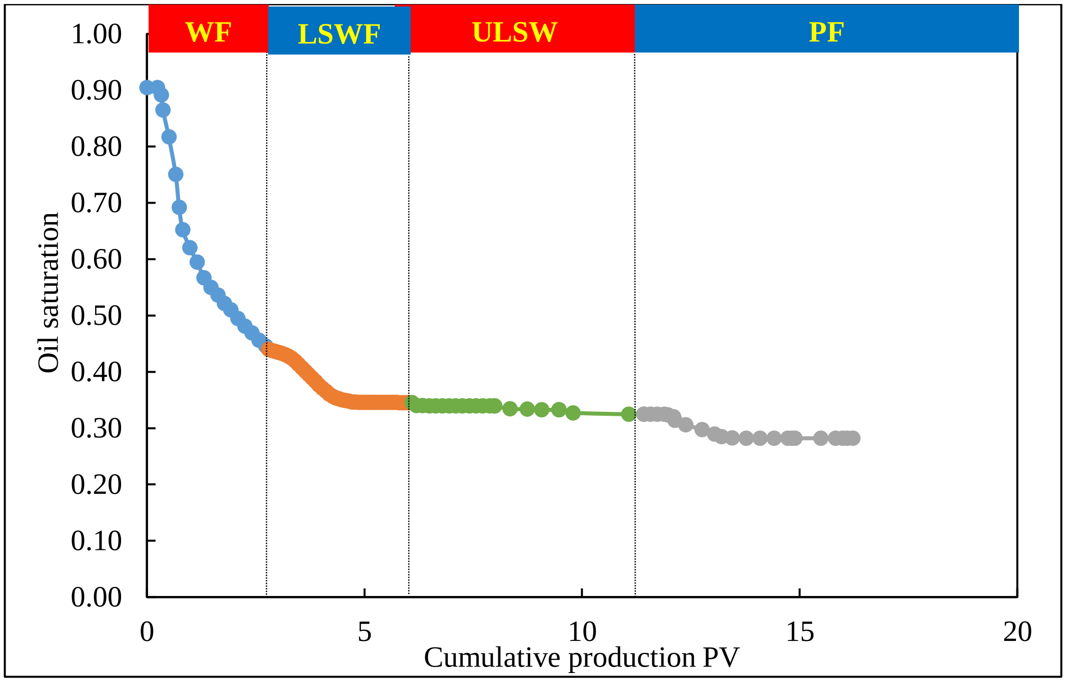

Figure 4.3 The average oil saturation in the sandpack (Exp. #1)

The injection pressure response is shown in Figure 4.4. It shows that during the first waterflood process, the pressures primarily increased to a peak point of 67.8 psi and then gradually dropped down. The decreased oil saturation reduced the resistance to the injected water, and thus the injection pressure was gradually declined. The pressure did not reach a stable condition at the end of the first waterflooding process because there was still oil produced out at that time and the stable oil saturation condition was not established. In the following LSWF process, the injection pressure would gradually rise to about 25 psi and become stabilized. A similar trend was observed in the following ULSWF, but the stable pressure was slightly higher about 27.5 psi.

During the polymer flood, the injection pressure significantly increased and stabilized at approximately 128 psi after 4.4 PV of polymer injection. It shows polymer could smoothly enter the porous media and did not result in plugging. After the polymer flood, about 10 PVs of SFB was injected into the sandpack at the same flow rate to measure the stable injection pressure. The resistance factor and residual resistance factor were evaluated for the polymer flooding based on the injection pressure data.

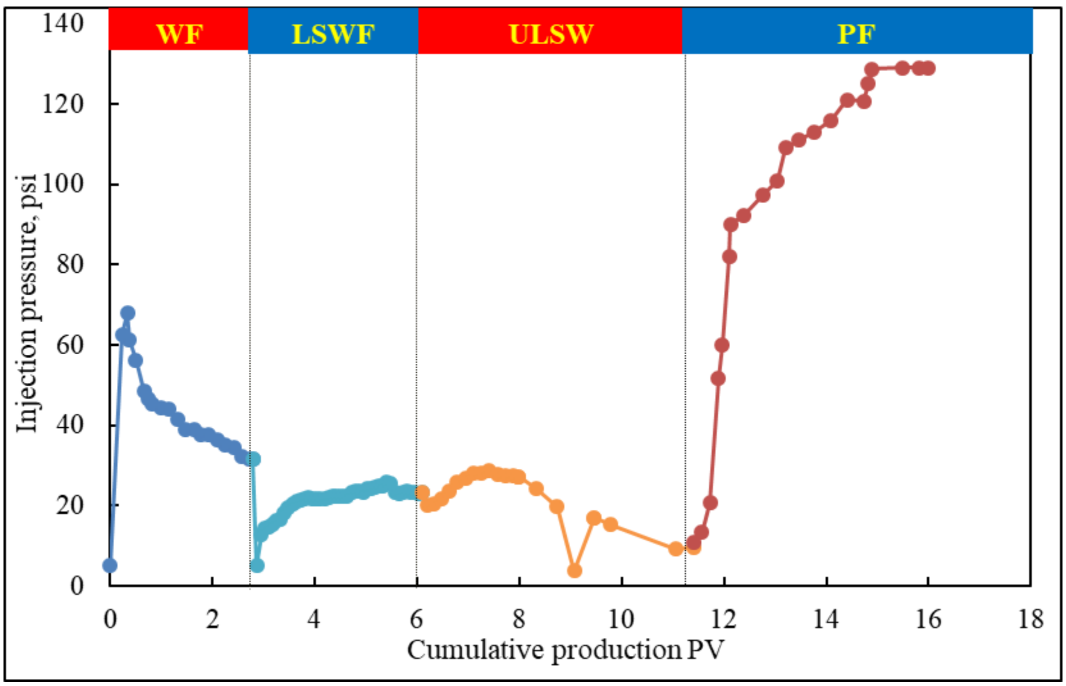

Figure 4.4 The pressure response (Exp. #1)

Resistance Factor (Fr)**:** The resistance factor is defined as the ratio of the water mobility to that of polymer (or the ratio of polymer injection pressure to the water injection pressure) at the same flowrate. It is a parameter to quantify the improvement of the mobility condition and stability of displacement of a polymer flooding compared with waterflooding. The following equations were used in calculating the Fr. Note that the pressure drop at the same flowrate should be used in the calculation.

$$F_r = \frac{\lambda_W}{\lambda_{LSP}} = \frac{k_{rw}/\mu_W}{k_{rlsp}/\mu_{LSP}} = \frac{\Delta p_{LSPF}}{\Delta p_{WF}} \tag{4.1}$$

Residual Resistance Factor (Frr)**:** The residual resistance factor is defined as the ratio of the stable post-water injection pressure to the stable water injection pressure before the polymer flooding (or the ratio of permeability before and after the polymer flooding). The Frr is a measure to describe the permeability reduction (also the injectivity reduction) caused by polymer flooding. The following equation was used to calculate the Frr. Note that the pressure drop at the same flowrate should be used in the calculation.

$$F_{rr} = \frac{k}{k'} = \frac{\Delta p'}{\Delta p} \tag{4.2}$$

The resistance factor and residual resistance factor during the PF have calculated by the given function. Which Fr is 14.2, Frr is 1.5.

The results of the first experiment show the LSWF could achieve remarkable additional oil recovery beyond the normal salinity waterflooding, and the polymer flooding, to some extent, could further improve the oil recovery, but the improvement (2% OOIP) was not significant when considering the high viscosity (45 cp). However, it is still too early to draw a definitive and repeatable conclusion that the performance of low salinity water flooding and polymer flooding is good or poor. More experiments are required to be carried out. Based on the first experiment, several improvements would be made when performing the other coreflooding experiments in this thesis.

(1) The pressure would be monitored at a higher frequency to capture any pressure response during the flooding process. Since the displacement is a transient process, rather than a steady one, especially at the early stage of each flooding process, some pressure response may be missing if the resolution is not high enough.

(2) The homogeneity of the sandpack cores would be checked and guaranteed. If a sandpack core was not well prepared, the sand in the sandpack was not evenly distributed, resulting in heterogeneity of porosity and permeability, and even the presence of high-permeability channels. When a displacement experiment was performed, the injected fluids would break through along the channels and cause a poor sweep efficiency. The observed results may be distorted and lead to erroneous estimations. The sandpack would be prepared with great caution. Wet-packing method was preferred which possesses advantages over dry-packing method. The wet-packing method would be described in more detail in Section 5.1. The sand was added into the sandpack tube at multiple times, and ~5 cm^3 for each time. After each addition of sand, a fixed number of oscillations were applied to the tube to make the sand more evenly distributed. Tracer test would be performed to check the homogeneity of the sandpack cores. Details of tracer test and corresponding results would be shown in Section 5.

(3) The viscosity of the produced polymer would be tested to evaluate whether the polymer go through any degradation as it flow through the porous media.

(4) Mechanical degradation of polymer may happen and decreases the viscosity of the polymer in the porous medium, diminishing the polymer flood performance. The viscosity of the produced polymer would be compared with the injected viscosity.

4.2. LOW SALINITY POLYMER (LSP) EFFECT ON SILICA SANDPACK EXPERIMENT

In this experiment, a low salinity polymer flooding (LSPF) was performed instead of the normal salinity polymer flooding in the base case experiment. The objective of this study was to evaluate the effect of low salinity polymer injection on the oil recovery factor and the effect of salinity on residual oil saturation.

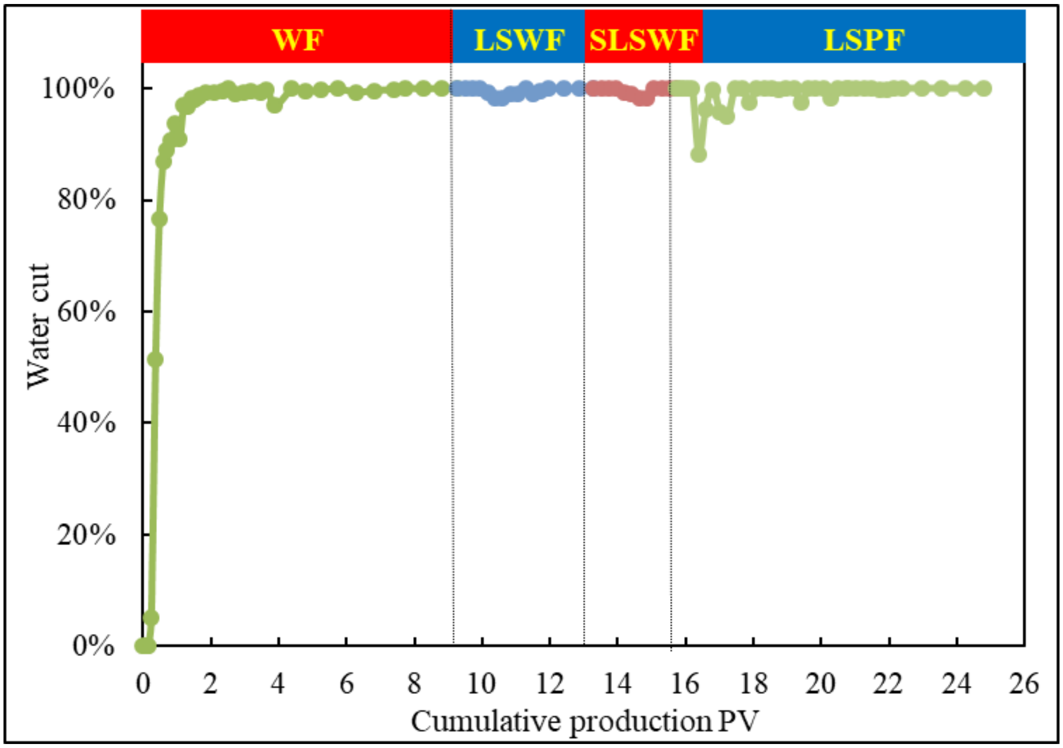

Figure 4.5 The water cut behavior (Exp. #2)

Figures 4.4 and 4.5 show the water cut and oil recovery factor. The injection rate was still 0.1 ml/min at the beginning of each flooding process. After no more oil was produced with the normal flow rate, it was increased in a stepwise manner to test the injection flowrate on the water cut and oil recovery performance. In case there was any oil production, the flooding would be continued until no more oil production with that flow rate. The first normal salinity waterflooding showed a similar trend in the base case experiment. The waterflooding process continued when the water cut reached 98% (oil recovery factor: 51.13%).

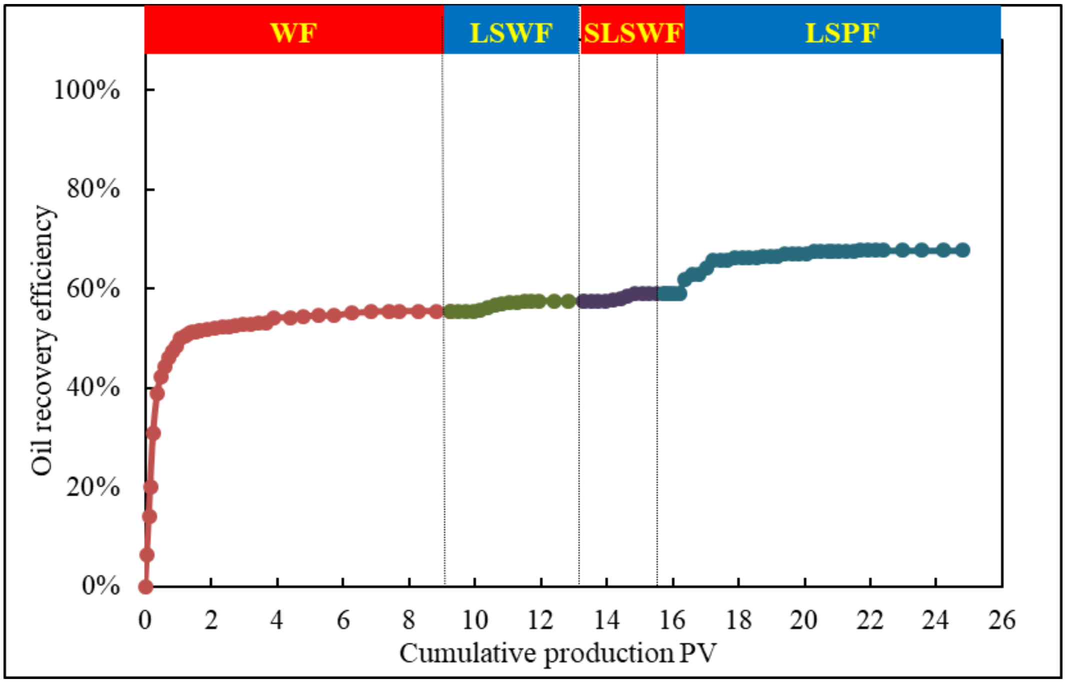

Figure 4.6 The oil recovery performance (Exp. #2)

Another several PVs of water was injected until to no oil was produced. About 3% additional oil was recovered after the water cut increased to 98%, and the overall oil recovery from this flooding process was 54.12%. In the following LSWF displacement, the water cut slightly decreased to about 98% with 1 PVs of SIB injection. The oil recovery factor was increased to 57.20%.

The comparison of oil saturation reduction curves in the #1 sandpack and #2 sandpack was shown in Figure 4.7. In the HSWF process, the oil saturation was decreased almost the same value between #1 and #2, and in the following LSWF, the oil saturation was reduced more in sandpack #1, oil saturation was only reduced 0.015 in sandpack #2. During the ULSWF the oil saturation almost did not change. Interestingly, the oil saturation in sandpack #2 was further decreased to 0.245. More oil was recovered from LSPF. LSPF can achieve a better performance in reducing oil saturation compared with polymer flooding under conventional salinity conditions.

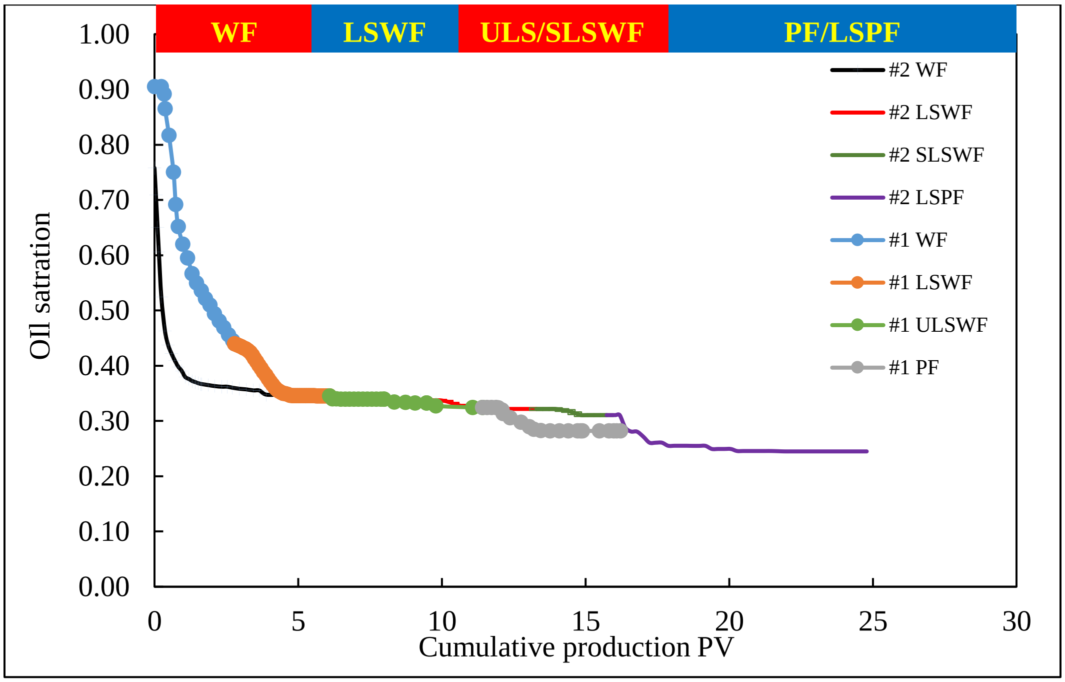

Figure 4.7 The average oil saturation in the sandpack (Exp. #1 vs Exp. #2)

The pressure curve is shown in Figure 4.8. At the initial stage, the injection pressure rapidly climbed to a peak of 11.9 psi, and then decreased and stabilized around 8.3 psi in the next 2.7 PVs of injection. The pressure increased and then slowly became stable as the injection rate increased in a stepwise manner. The effect of injection flow rate will be discussed right below. In the following LSWF process, the injection pressure increased to 7 psi and become stabilized. A similar trend was observed during SLSWF, but the stable pressure was slightly higher at about 9.8 psi. During the LSPF, the injection pressure significantly increased and stabilized at 35 psi after 1.7 PVs of polymer injection.

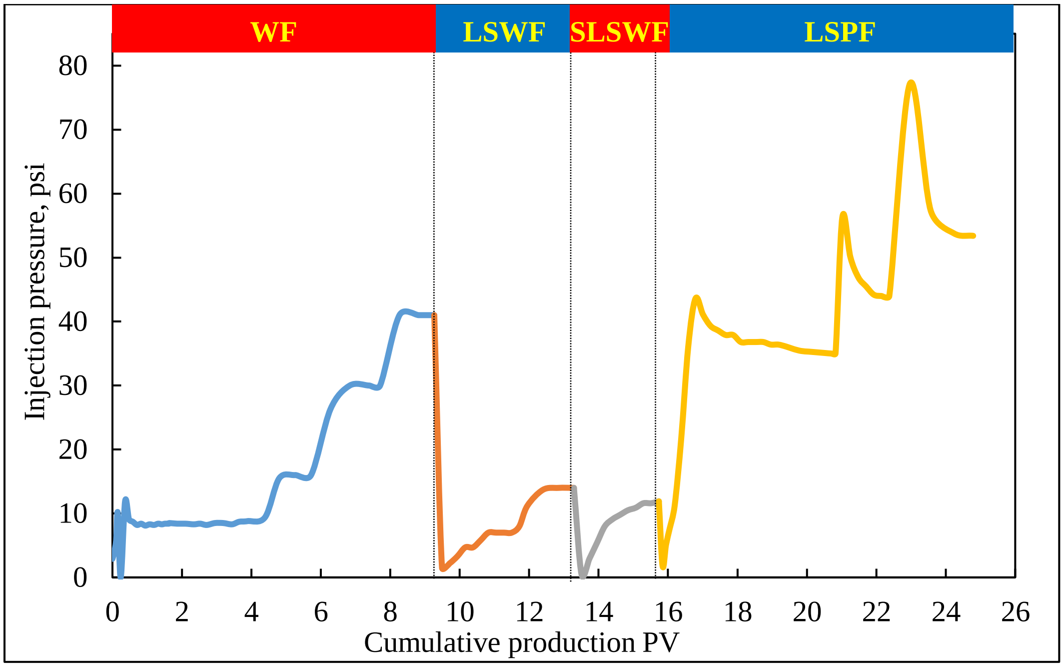

Figure 4.8 The pressure response (Exp. #2)

The resistance factor and residual resistance factor during the PF have been calculated. The Fr was 25, and the Frr is about 1.5.

To investigate whether the flow rate impacts oil recovery performance. Different injection flow rates were used to flood the sandpack after flooding with the normal injection flow rate as shown in Figure 4.6 and 4.8. In the first water flooding process, there was no oil produced out after about 5 PVs of SFB flooding. Afterwards, the injection rate was sequentially increased to 0.2, 0.5 and 1.0 ml/min. The injection pressure increased accordingly. However, the water cut almost did not reduce, and the oil recovery improvement was negligible, only 1.3% OOIP. The same trend was observed in LSWF and LSPF, only 0.2% and 0.1% OOIP, respectively.

As shown in Figure 4.9, the LSPF could achieve a higher recovery improvement than HSP (8.67% OOIP versus 4.85% OOIP). The LSPF achieved significant extra oil production in the sandpack #2. The incremental oil recovery may be attributed to multiple mechanisms including increased microscopic sweep efficiency and the combined effect of low salinity. Wettability was discussed in many papers as a key parameter of LSE. However, changes in wettability are not well documented. Wettability tests were rarely performed before and after salinity changes, and most indicators are determined based on the relative permeability of water or the shape of the oil production curve.

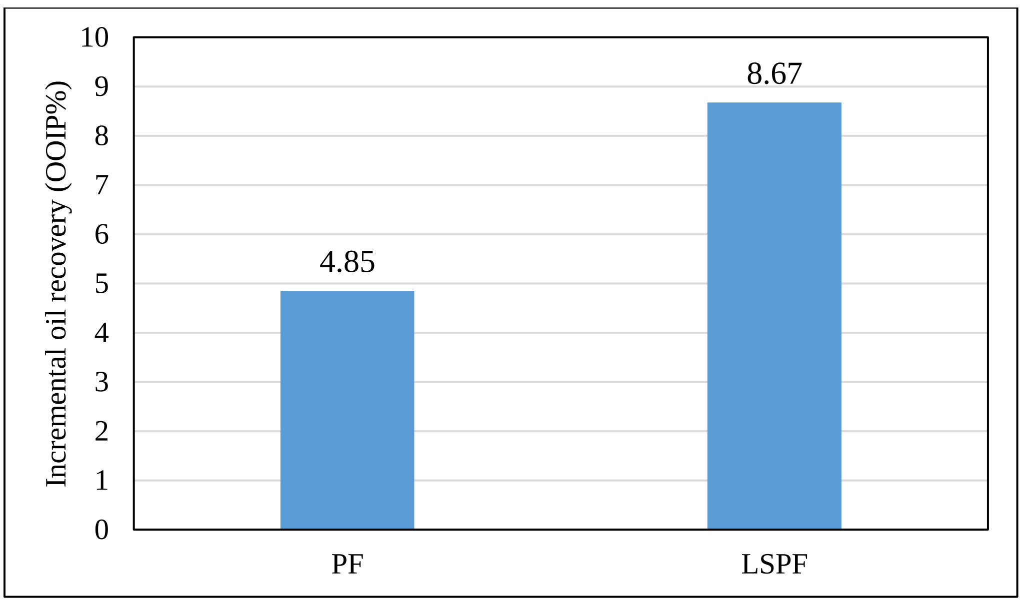

Figure 4.9 The Incremental oil recovery PF vs LSPF

Research by Tang and Morrow (1999) shows that the properties of crude oil and rocks, and the presence of primary water, all play a crucial role in the sensitivity of crude oil recovery to the composition of brines. In contrast, injecting low salinity brine would moderately increase the recovery factor. Experimental results for secondary and tertiary low salinity polymer were reported, providing insightful information for water-wet and non-water-wet rocks, as well as results for outcropping sandstones with different clay content. Most importantly, this study focuses on the remarkable benefits of low salinity combined with polymer or low salinity polymer flooding, especially in the secondary mode. (Skauge and Shiran 2017)

4.3. EFFECT OF INJECTION SEQUENCE

The injection sequence of polymer flood can influence oil recovery performance. In this section, LSWF was started at the very beginning, instead of normal-salinity water flooding. In this regard, the LSWF was implemented in a secondary recovery mode. After no more oil produced out, the LSWF was switched to LSPF. During each flooding process, the injection flow rate was kept at 0.1ml/min until no oil was produced. Afterwards, the injection rate was sequentially increased to 0.2 0.5 1.0 ml/min.

The water cut and oil recovery are shown in Figures 4.10 and 4.11. The water breakthrough occurred at 0.5 PVs of SIB injection. An oil recovery efficiency of 73.3 OOIP% was achieved with the first LSWF. In this process, a total of 15 PVs of SIB was injected into the sandpack. No oil was produced for 5 pore volumes of injection at the end of the LSWF. Some unusual behavior was noteworthy when taking a close look at the LSWF process. Practically, a water cut of 98% is usually applied as an economical limit of production. In this experiment, the water cut reached 98% after 1.9 PVs of injection. At that time, two-third of the OOIP was recovered. This value is higher than the field-scale water flood because the results were obtained from sandpack. It was observed that there was still oil produced over a long flood process, over 6 PV of injection, though the water cut stayed at a very high level. During this period, nearly 7% more oil was recovered, after the water cut reached 98%. Then LSP was injected, the water cut was decreased to as low as 75.4% at 0.53 PVs of LSP injection. After 3.2 PVs of injection, no more oil was produced. The final oil recovery factor was 82.93%.

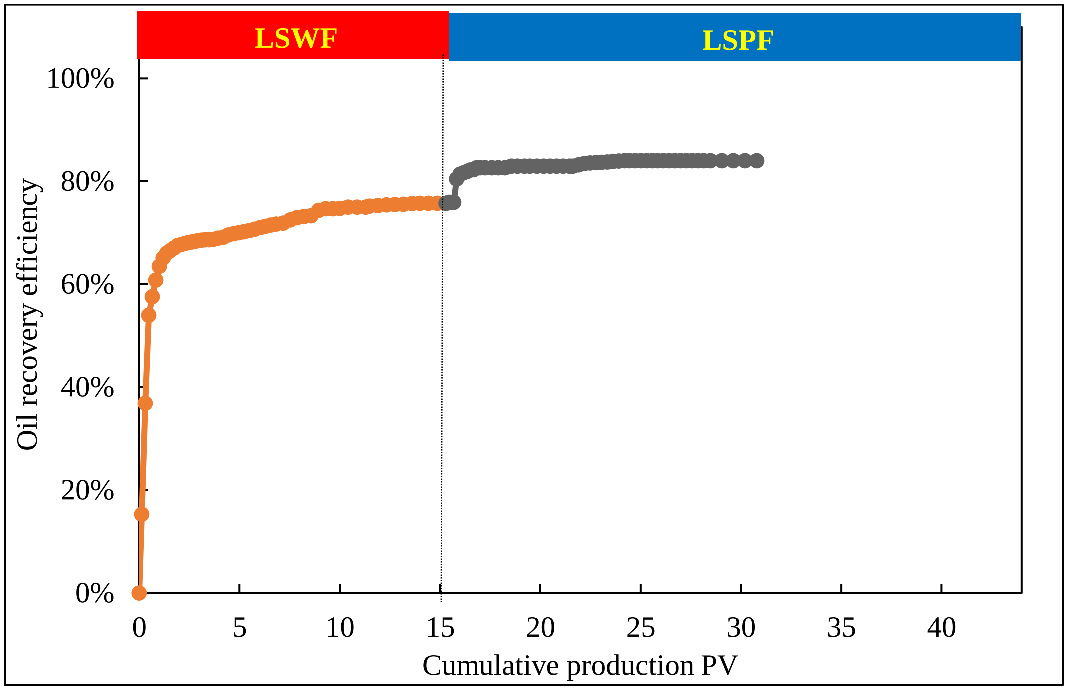

Figure 4.10 The oil recovery performance (Exp. #3)

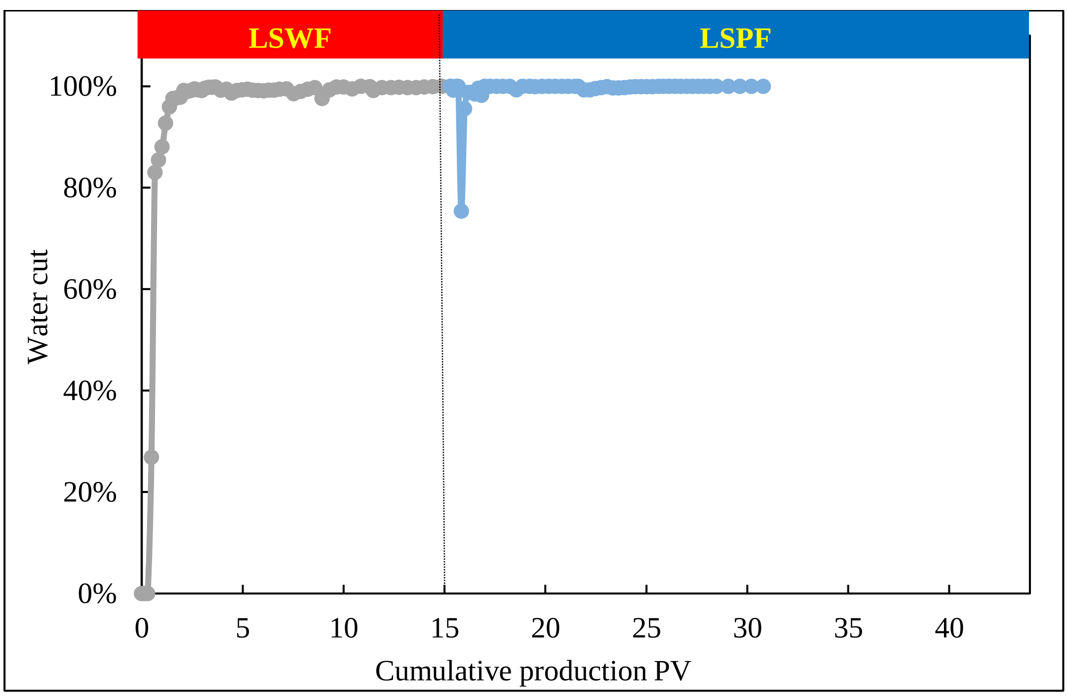

Figure 4.11 The water cut behavior (Exp. #3)

The pressure response was shown in Figure 4.12. In the LSWF process, the injection pressure would first increased to a peak of 13 psi, then gradually decreased, and tended to be stable at 1.6 psi. In the LSPF, the injection pressure significantly increased and stabilized at 20 psi after 5 PV of polymer injection.

After increasing the injection flow rate, the water cut almost did not reduce and the oil recovery improvement was negligible, only 2% OOIP. A similar trend was observed in LSPF, just 1.7% OOIP. The results were consistent with the observations in the second experiments. This process would not be repeated in subsequent experiments.

The oil saturation went through a significant reduction as shown in Figure 4.13. After the LSWF process, the oil saturation was reduced from 0.81 to 0.194. In the LSPF process, the oil saturation was further decreased to 0.128.

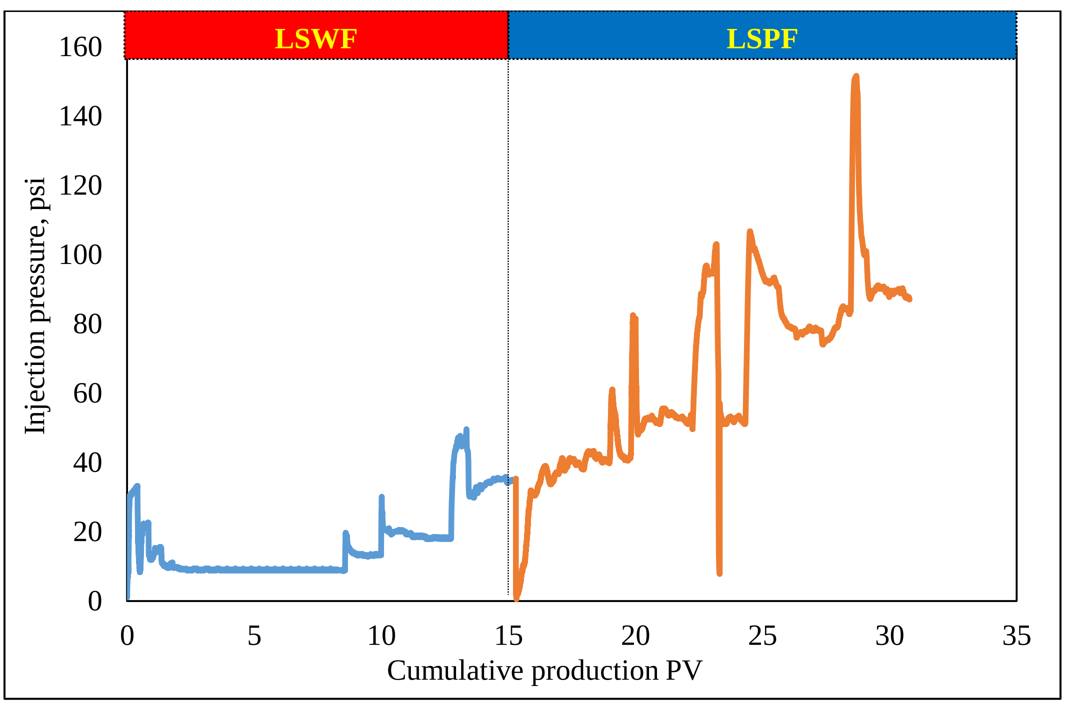

Figure 4.12 The pressure response (Exp. #3)

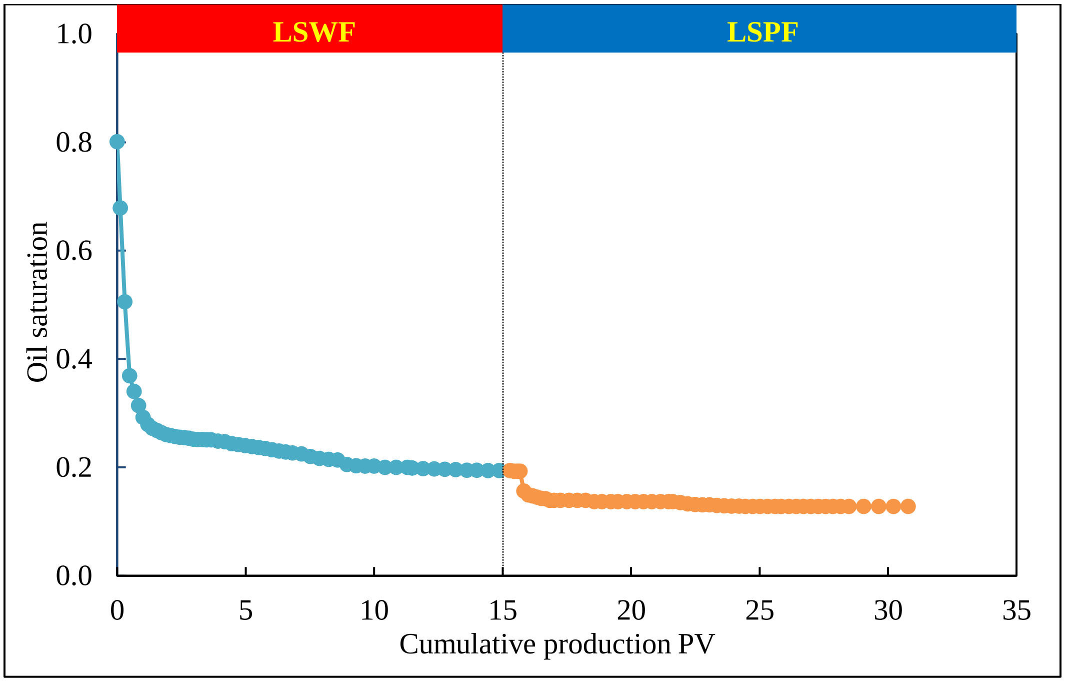

Figure 4.13 The average oil saturation in the sandpack (Exp. #3)

Table 4.2 Comparison of first water flooding performance

Exp number	Water breakthrough (PV)	Oil recovery at fw =80%	Oil recovery at fw =98%	Oil recovery at the end
#1	0.29	37.35%	51.38%	51.38%
# 2	0.36	45%	51.13%	54.12%
# 3	0.50	55%	67.52%	73.3%

Comparison of first water flooding performance was shown in Table 4.2. Compared the three experiments, it was observed that in the LSWF the water breakthrough was later than in normal-salinity WF. The oil recovery factor as water cut reached 80%, the LSWF can achieve a higher oil recovery factor of 7.65 % while the oil recovery was 37.35% for the normal-salinity WF. When the oil recovery factor reached 98%, the LSWF could achieve a higher oil recovery factor of 16.14% compared with the normal-salinity WF. At the end of the waterflooding process, the LSWF can achieve a higher oil recovery factor of 20.92%. Overall the LSWF can achieve a better oil recovery performance compared with the normal-salinity WF.

Table 4.3 Comparison of polymer flooding performance.

Exp number	Oil recovery improvement	Fr	Water cut reduction	Duration of fw < 98% （PV）	Oil recovery at the end
# 1 HSP	4.85%	14.2	5%	1.3	68.98%
# 2 LSP	8.67%	25	12%	1.7	67.68%
# 3 LSP	8.27%	5.9	25%	1.6	84.3%

Table 4.3 shows the comparison of polymer flooding performance. In the first experiment, the HSPF OOIP increased 4.85%. LSPF OOIP was increased by 8.67% and 8.27%, respectively, in the next two experiments using LSP. The water cut decreased by 5%, 12%, and 25%, respectively. Compared with PF, LSPF can more significantly reduce the water cut. Moreover, the duration of fw below 98% was continued for 1.3 PV in the PF. The PV stabilized in LSP was 1.7 and 1.6. The comparison suggests that the LSPF can not only reduce the water cut to a lower level, but also it can keep a longer relatively-low-water-cut period of production. As a consequence, the LSPF shows a relatively better oil recovery performance compared with normal salinity polymer.

4.4. SUMMARY OF SILICA SANDPACK EXPERIMENTS

The sandpack experiments indicate that LSWF can reduce the residual oil saturation and increase the oil recovery of the heavy oil. The performance was limited if the hardness of LSF is removed.

Polymer flooding can further reduce the residual oil saturation and increase oil recovery. Low salinity polymer flooding can achieve a better performance than normal salinity polymer flooding.

The positive effect of low salinity water and low salinity polymer on oil recovery has been demonstrated through these experiments. An incremental oil recovery of 2-6% OOIP was achieved by low salinity water flooding. An incremental oil recovery of 8% OOIP was obtained from low salinity polymer flooding. Starting directly with low salinity water (secondary mode) can achieve a higher ultimate oil recovery compared with starting with high salinity water flooding (Tertiary mode).

5. FORMATION SANDPACK EXPERIMENT RESULTS

In this section, four sandpack experiments were carried out using reservoir sand samples. The sand was from a reservoir formation (NB) on the Alaska North Slope, provided by Hilcorp LLC. The NB formation was poorly consolidated, making it nearly impossible to sample intact core plugs from the reservoir. Instead, what came out was loose sand mixed with reservoir fluids, most of which was viscous oil. The loose sand was used to prepared the sandpacks. Orginal sand and clean sand were used in different sandpack flooding. The sand was cleaned with toluene and ethanol to remove oil covered on the sand.

Table 5.1 Properties of formation sandpack experiments

Sandpack #	d, cm	L, cm	A, cm^3	PV, cm^3	porosity	K, md	Flooding process
NB-1 (clean sand)	2.54	20.40	5.07	29.45	0.285	1469	(1) WF (2) LSWF (3) PF (4) LSPF (5) PF
NB-2 (orignal sand)	2.54	20.40	5.07	42.85	0.415	1770	(1) WF (2) LSWF (3) PF (4) LSPF
NB-3 (clean sand)	2.54	20.40	5.07	32.71	0.316	478	(1) WF (2) LSWF (3) LSPF (4) PF
NB-4 (clean sand)	2.54	20.40	5.07	24.35	0.236	248	(1) PF (2) LSPF

The purpose of the experiment includes: (1) to confirm the reproducibility of the positive performance of low salinity waterflood and low salinity polymer flood observed in the previous experiments; (2) to investigate the effect of original wettability of sand on oil recovery performance; (3) to investigate and optimize the injection sequence of polymer solutions; and (4) to evaluate the effect of starting time of polymer flood. Table 5.1 shows the NB sand pack properties.

5.1. THE RESULT OF BASE CASE EXPERIMENT

5.1.1. Preparation of Clean Sand. The original sand, as sampled from the target formation, was a mixture of the formation sand and fluids. Since the sand had been stored for about ten years since it was sampled, some fluids had been lost due to evaporation, but the sand was still coated with viscous oil. The original sand was more oil-wet. A soxhlet extraction apparatus was used to remove the oil, other organic matters and water associated with the sand. As shown in Figure 5.1, toluene was slowly boiled in a Pyrex flask. Its steam moved upwards, and the sand was engulfed by toluene vapor (at about 120 degrees Celsius). Eventually, the water in the sample inside the thimble will evaporate. Toluene and water vapor enter the condenser chamber. The cold water circulating in the inner chamber condenses the two vapors into insoluble liquids. Then the condensed toluene and liquid water dripped from the bottom of the condenser to the sample of the thimble. The toluene soaks the sand and dissolves any oil that has comes in contact with it. When the liquid level in the tube has reached the top of the siphon arrangement, the liquid in the soxhlet tube was discharged automatically by siphonage and flowed into the boiling flask. As the solvent continues to be extracted, the color becomes lighter. After 48 hours, the toluene solution becomes colorless and transparent. After removing the sand, continue to wash with ethanol three times until the solution is colorless and transparent. Then the sand was dried for 3 days, the cleaning process was completed. Figure 5.2 shows the original sand and cleaned sand. After removing the coated oil on the surface, the sand would become more water-wet.

Figure 5.1 The Soxhlet Extraction Apparatus

(a) The original formation sand (b) The cleaned formation sand

Figure 5.2 The original formation sand and the cleaned formation sand

5.1.2. Preparation of the Sandpack. The wet packing method was adopted because air bubbles in the pore could be avoided with this method. First, the cleaned and dried sand was mixed with SFB at the ratio of 100g:10ml. According to the volume of the sandpack, at least 400g wet sand that should be prepared. In the following step, the wet sand was added into the tube at multiple times, ~5g/time. After each addition of the sand, the tube was stricked and vibrated five times with the same force using a hammer to make the sand distribute as uniform as possible. The homogeneity was confirmed by the tracer test, which would be described in the next subsection. The same method was used to packing all these sandpacks.

5.1.3. Examination of the Homogeneity of the Sandpack. A tracer test was performed by injecting tracered SFB after saturated with SFB. The tracer test was conducted at a flow rate of 0.1ml/min to test the homogeneity of the sandpack. The tracer was potassium iodide dissolved in SFB with a concentration of 40 ppm. Effluent samples were collected every 40 minutes, with a sample size of 4 ml, and the tracer concentration in each tube was measured with Shimadzu UVnini-1240 UV-vis spectrophotometer. A series of tracer solution with known tracer concentration prepared with SFB was tested with the spectrophotometer to establish a standard curve as reference. The absorbance at the peak of 225 nm was proportional to the tracer concentration. The normalized tracer concentration (the ratio of effluent concentration to the injected tracer concentration) was plotted against the injected pore volume, as shown in Figure 5.3. The tracer concentration was increased sharply to the original concentration after 1 PVs of injection.

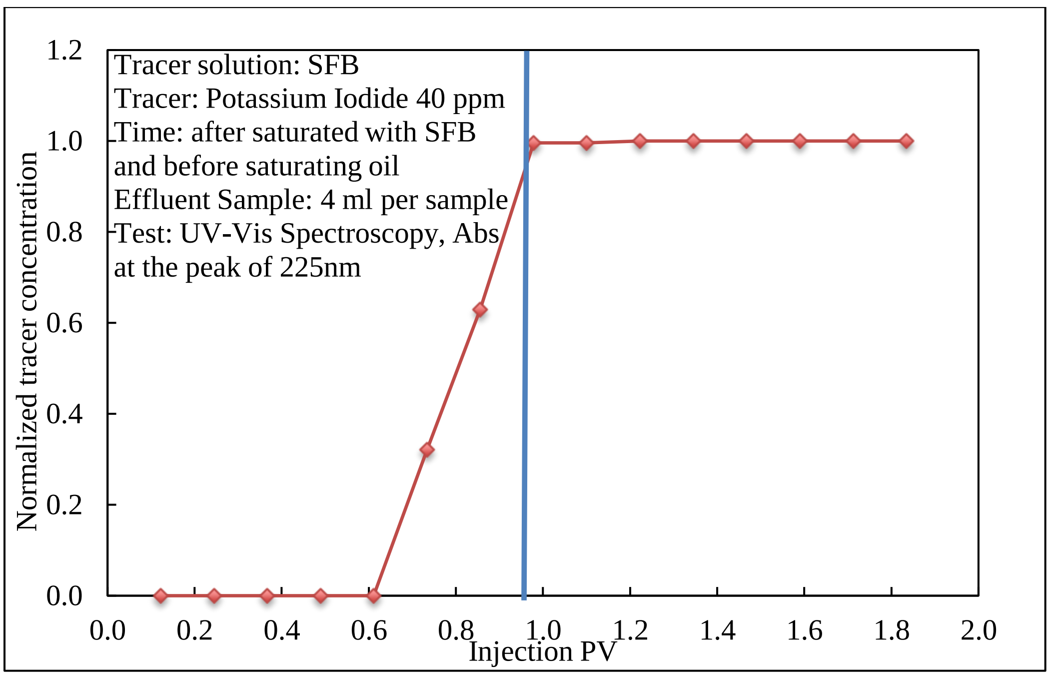

Figure 5.3 The tracer test result of the base case sandpack

The sharp increase and quick equilibration indicate the prepared sanpack was very homogenous. The other sandpacks prepared in this study were examined following the same procedure. Results also demonstrated satisfactory homogeneity.

5.1.4. Coreflooding Results and Discussion. The water cut and oil recovery are shown in Figures 5.4 and 5.5. As shown in Figure 5.4, waterflooding with normal salinity was performed with extensive pore volumes of injection. The SFB was injected at a flow rate of 0.1 ml/min for 17 PV, which made the flow velocity in the porous media to be approximately 1 ft/d, typically representing the flow velocity in a matrix of an oil reservoir in the field. Water breakthrough occurred at 0.3 PV. After the water breakthrough, the water cut was increased sharply. As the water reached 80% (Figure 5.5), after 0.72 PVs of SFB injection, the oil recovery factor was increased to 36.78%. The water cut has reached an economic limit in which the water cut was 98% after 2.26 PVs of injection. Another 14.7 PVs of SFB was then injected until no oil was produced, and the recovery factor was 52.40%. The next displacement process was LSWF. After the injection of 0.6 PVs of SIB, the water cut decreased to 99% (Figure 5.4). Another 6.9% of OOIP more oil was recovered from the LSWF, and the oil recovery factor was increased to 59.3%. This positive result is essentially the same as the silica sand experiment. This indicated that LSWF recovery improvement in the NB formation sand could also be further improved beyond the normal salinity waterflooding.

The next displacement process was the injection of polymer, which had the same composition and viscosity as the polymer solution used in the previous experiments in Section 4 (Flopaam 3630, normal salinity, 45 cp). The injection was still performed at the rate of 0.1ml/min. After the injection of 1.5 PVs of polymer solution, the water cut decreased to 97% (Figure 5.5), and about 2% of OOIP more oil was extracted. Oil production can also be seen in the tube shown in Figure 5.4. The water cut did not decrease dramatically compared to previous experiments because of the amount of water injected. Nevertheless, the oil recovery factor was increased to 63.8%, a total increase of 4.55% beyond the extensive waterflooding. Afterwards, the LSP (Flopaam 3630, 45cp, prepared with SIB) was injected into the sandpack and the LSP was observed to be still effective in this displacement. After the injection of 1.7 PVs of polymer, the water cut decreased from 100% to 98% (Figure 5.4), and 2.9% OOIP additional oil was achieved. The flooding was continued until definitively no oil was produced. The overall oil recovery was increased to 66.7%. The final injection volume of LSP was 14.4 PVs, and most of the incremental oil was obtained during the first 5 PVs of flooding. A further round of PF was conducted, and no oil was produced, suggesting that further switching to polymer flooding with higher salinity after LSPF did not improve the oil recovery performance.

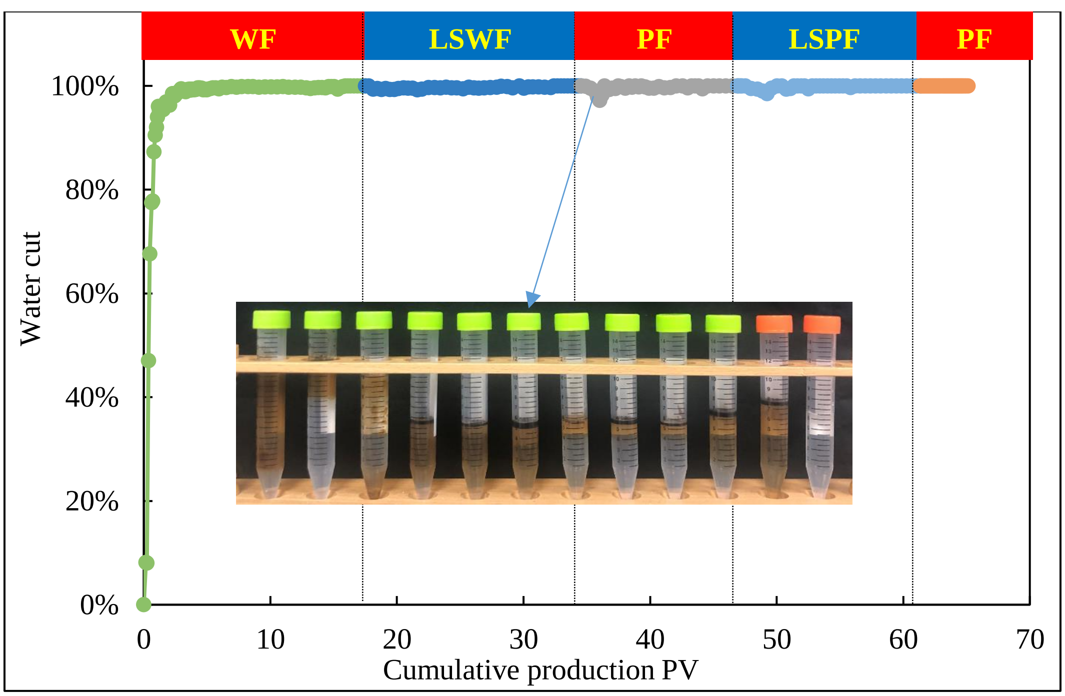

Figure 5.4 The water cut behavior (Exp. #NB-1)

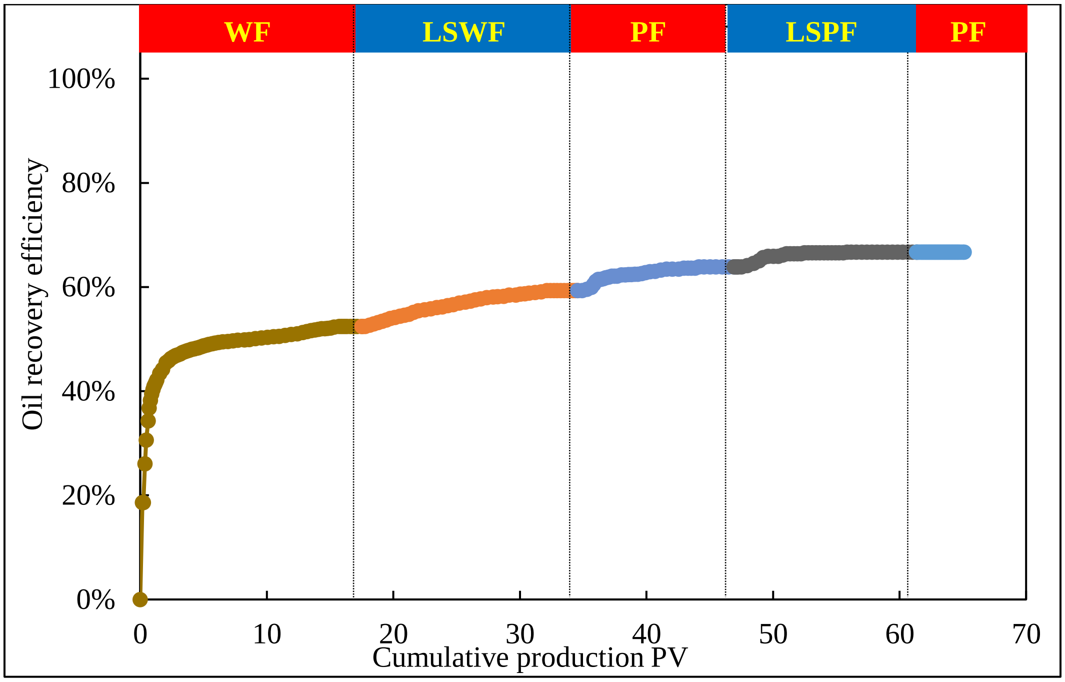

Figure 5.5 The oil recovery performance (Exp. #NB-1)

The oil saturation in the sand pack was reduced accordingly in the flooding process, as shown in Figure 5.6. In the WF process, the oil saturation was reduced from 0.822 to 0.391, and in the following LSWF the oil saturation was reduced to 0.334. During the PF the oil saturation changed to 0.297, and the oil saturation was further decreased to 0.274 by the LSPF.

The pressure response was shown in Figure 5.7. The pressure curve shows that during the first waterflood process the pressure first increased to a peak point 4.6 psi, and then gradually decreased, the decreased oil saturation causes the pressure reduction in the sandpack, so the resistance to the injected water was decreased, the pressure reached a stable condition at the end of the flooding process. The stable pressure was 0.6 psi at the end of this flooding process. In the following LSWF process, the injection pressure was gradually increased to about 0.95 psi and become stabilized. The peak pressure was smaller than the pressure in WF.

During the PF displacement, the pressure rose rapidly to 3.7 psi, then dropped and then rose to a peak of 3.9 psi. The pressure then fluctuated in a zigzag fashion and finally stabilizes after the injection of 10 PVs of polymer. A similar pressure behavior was observed during the following LSPF. After reaching a peak, it fluctuated in a zigzag pattern and finally tended to be stabilized. It might be due to the movement (repacking) of the unconsolidated loose sand forced by the viscous polymer.

The Fr and Frr were calculated using the formulas given in the previous section. The Fr and Frr were 6.98 and 1.17 respectively for the normal salinity polymer. For LSPF, the Fr and Frr were 7.94 and 1.34 respectively.

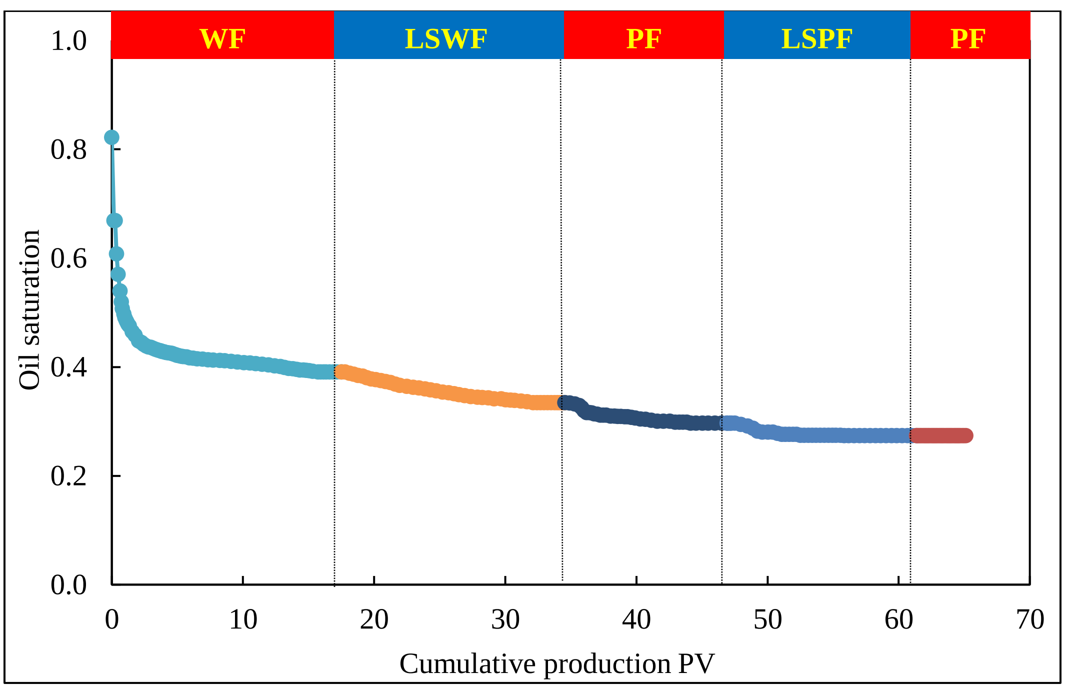

Figure 5.6 The average oil saturation in the sandpack (Exp. #NB-1)

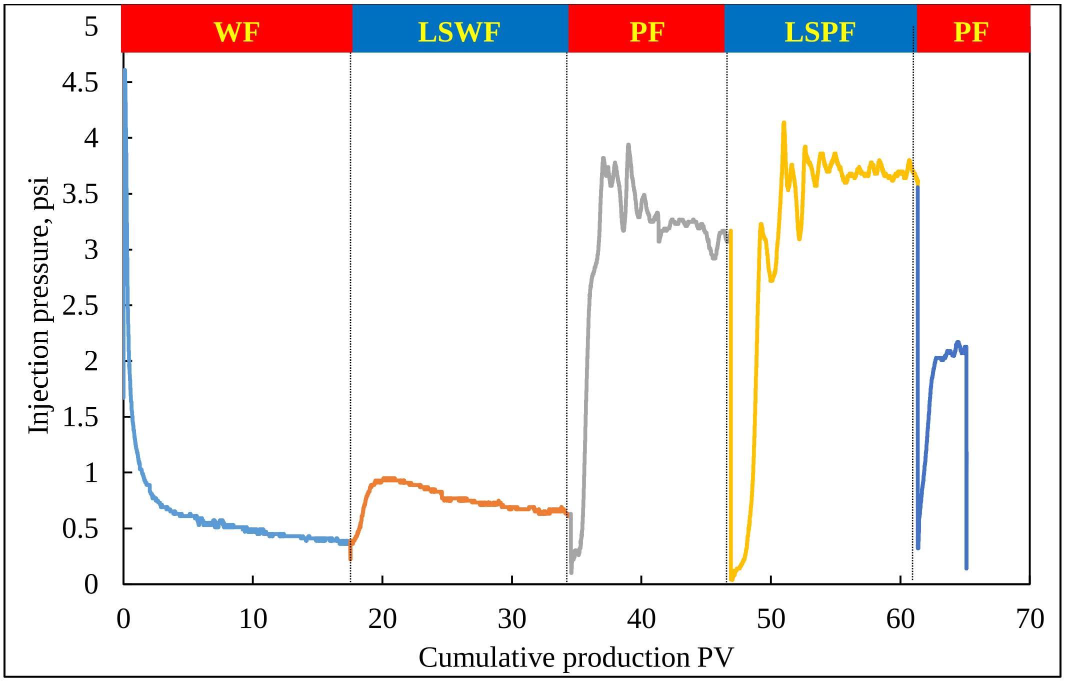

Figure 5.7 The pressure response (Exp. #NB-1)

The viscosity of the produced liquid (aqueous phase) was measured with a DV3T viscometer at the end of the test. The UL adapter was used to measure the viscosity at different shear rates. The samples tested were collected at the end of the corresponding flooding process. At that time the injection pressure had reached a stable condition and no oil was produced. The effluent viscosity was expected the same as the injected polymer if there was no degradation. The dimensionless viscosity (the ratio of effluent viscosity, μe to the viscosity of injected fresh polymer solution, μin) was plotted against the shear rate (Figure 5.8). For both polymers, the dimensionless viscosities were less than one, indicating viscosity loss as the polymer transported through the porous media. Note that the viscosity loss of LSP was 15.3% and that of normal polymer was 30.96% (Figure 5.9). The viscosity loss of LSP was less than that of normal-salinity polymer, indicating the LSP has better stability in the process of displacement.

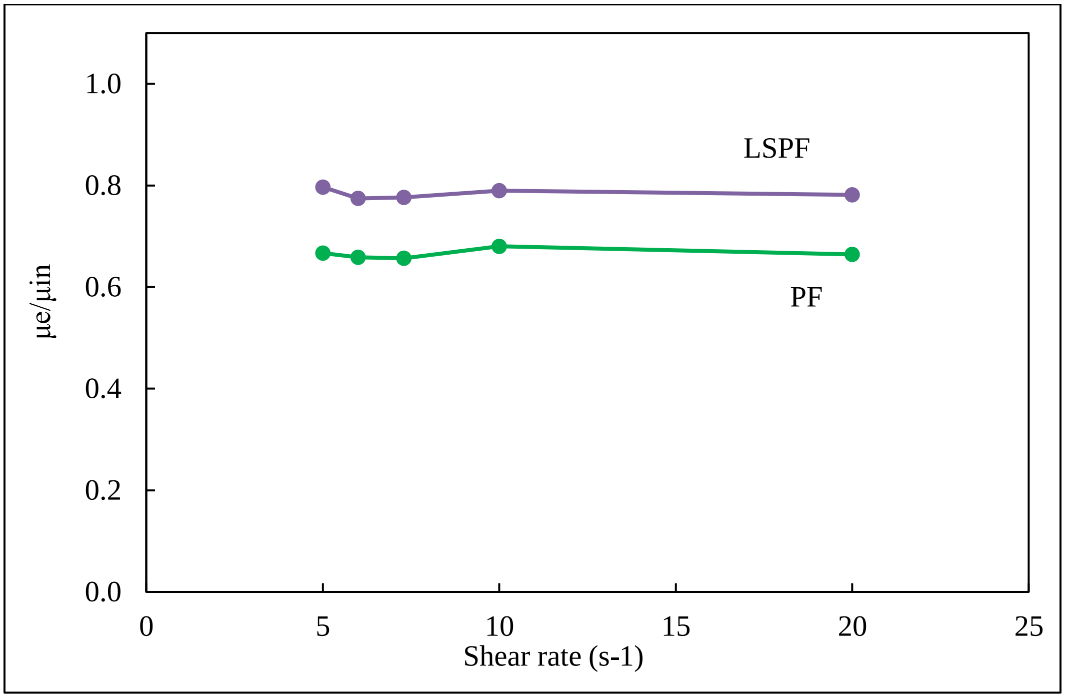

Figure 5.8 The effluent viscosity of PF and LSPF

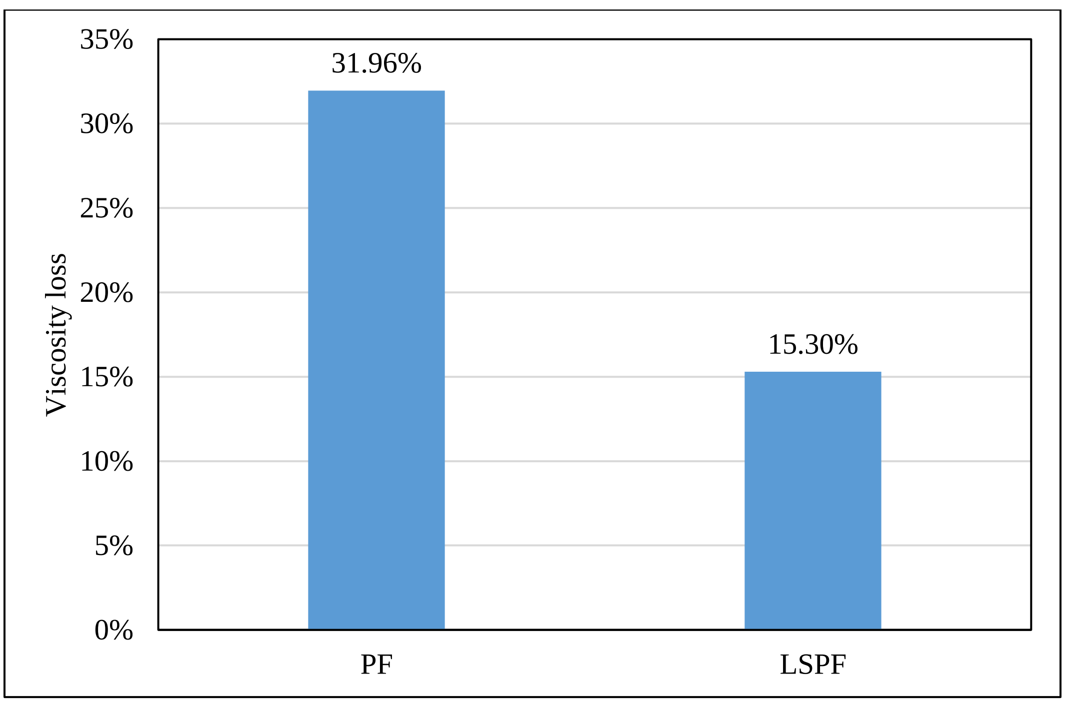

Figure 5.9 The viscosity loss of PF and LSPF

5.2. THE EFFECT OF ORIGINAL WETTABILITY OF SAND ON OIL RECOVERY PERFORMANCE

The purpose of this set of experiment was to investigate whether the initial wettability of sand would affect the oil recovery performance. The displacement processes were the same as in the previous experiment, except that original sand (coated with viscous oil) instead of clean sand was used to prepared the sandpack. The original sand should be more oil-wet due to long time contact with oil.

The water cut behavior and oil recovery performance were shown in Figures 5.10 and 5.11. First, the normal salinity waterflooding was conducted, the water breakthrough was observed with the injection of 0.2 PVs of SFB, and the corresponding oil recovery factor was 14%. After that, the water cut rose rapidly, reaching 80% at the injection of 0.37 PVs, and the recovery factor was 19%. Afterwards, the water cut rose more slowly, and the water cut after further injection of 2 PVs of SFB reached 98%, at which time the recovery factor was 32.5%. The water cut remained staying above 98% and gradually approaching 100%, i.e. no oil production at all. In total, 16 PVs of SFB was injected. The ultimate recovery factor was 37.85%. The normal salinity waterflooding was followed with LSWF. The water cut was not significantly decreased and has remained above 98%. However, LSWF did provide a positive effect, increasing OOIP by 8.71% after injection of 18 PVs of SIB. The water cut did not decrease rapidly after switching to polymer flooding, and the water cut decreased to 97% after injecting 0.6 PVs of polymer. After that, the water cut stabilized above 98% and approaching 100%, resulting in a final recovery factor of 53.9%. After 11.3 PVs of LSP was injected, 7.94% OOIP additional oil was continuously recovered though the water cut stayed at a relatively high level.

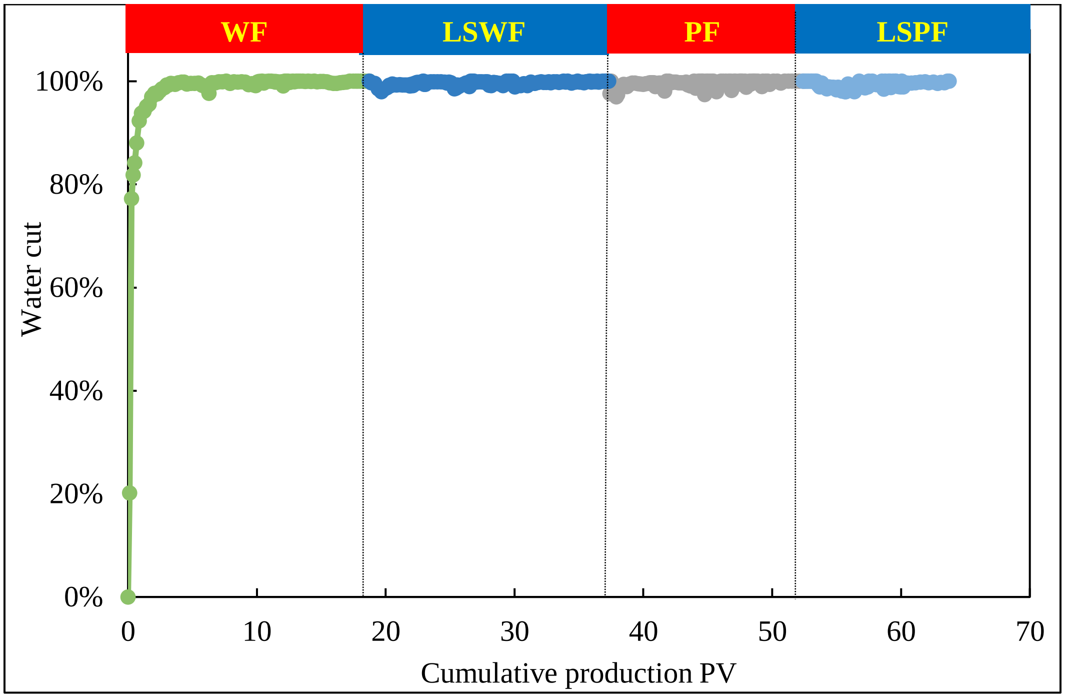

Figure 5.10 The water cut behavior (Exp. #NB-2)

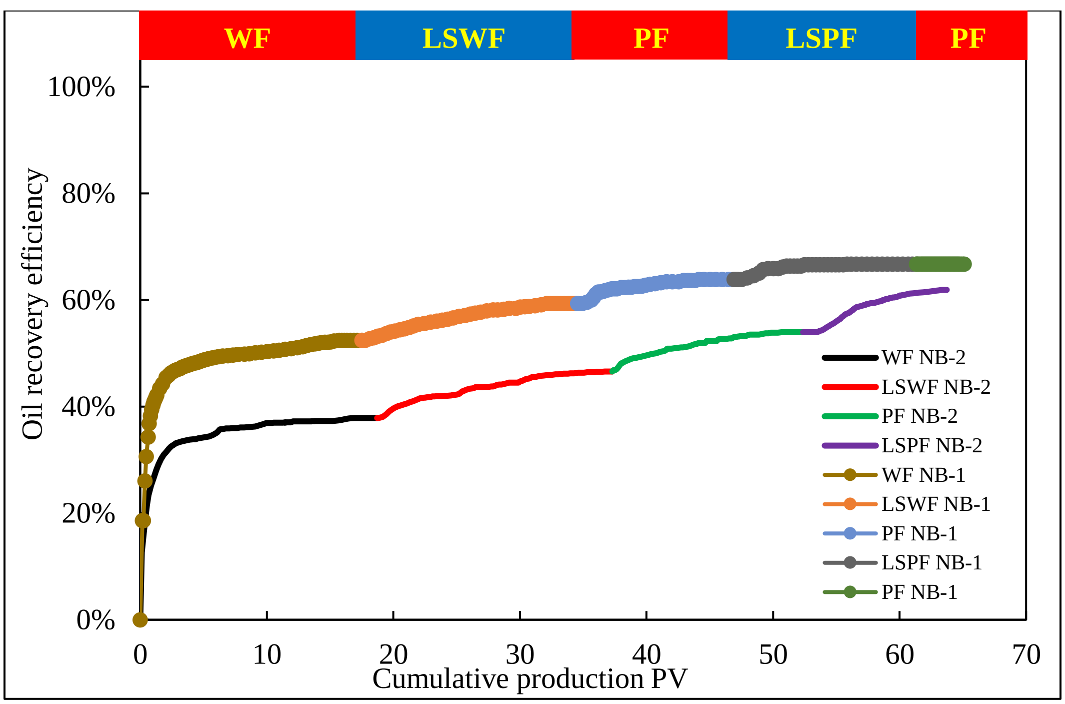

Figure 5.11 The oil recovery performance (Exp. #NB-2 VS #NB-1)

The oil saturation in the sand pack was reduced accordingly in the flooding process, as shown in Figure 5.12. In the normal salinity waterflooding (WF) process, the oil saturation was reduced from 0.84 to 0.52, and in the following LSWF, the oil saturation was reduced to 0.45. During the normal salinity polymer flooding (PF), the oil saturation changed to 0.39, and the oil saturation was further decreased to 0.32 by the LSPF.

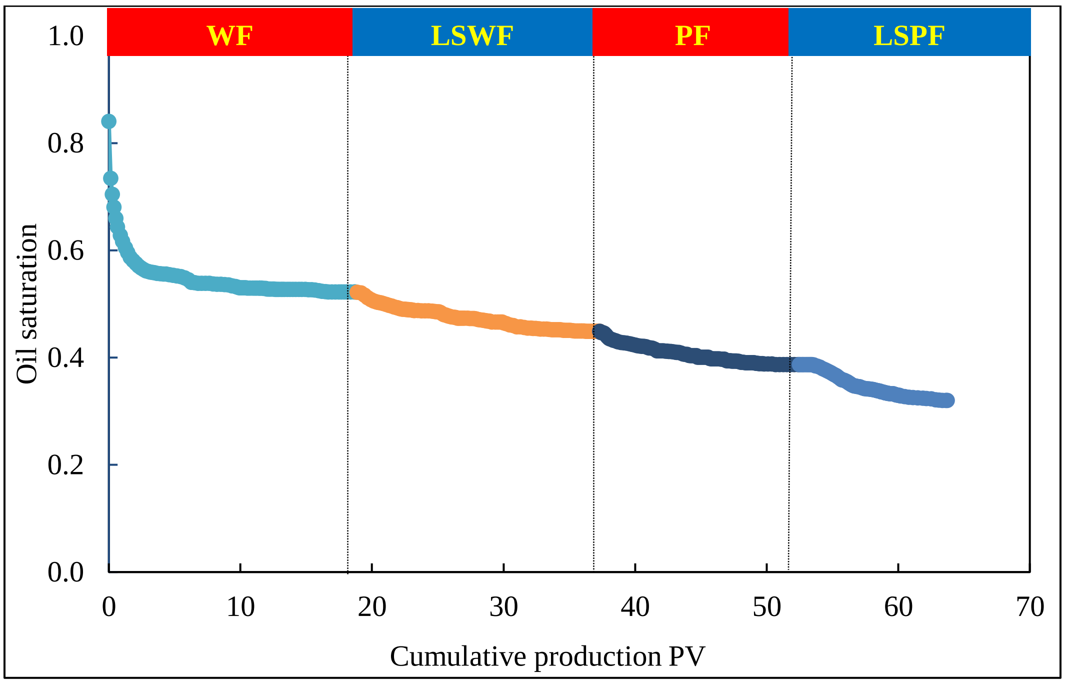

Figure 5.12 The average oil saturation in the sandpack (Exp. #NB-2)

The pressure response was shown in Figure 5.13. It shows that during the first waterflooding process the pressure first increased to a peak point of 7 psi, and then gradually decreased and stabilized at about 0.5 psi, the trend of the pressure curve was similar to that observed in the previous experiments. In the following LSWF process, the injection pressure would gradually increase to about 3.8 psi and become stabilized. During the PF displacement, the pressure rose rapidly to 2.8 psi, then dropped and stabilized at 2.3 psi. During the LSPF displacement, the pressure rose rapidly to 5.6 psi, then gradually decreased and stabilized at 4.5 psi. Because the pressure sensor with a larger range was used in this experiment, the recorded pressure data would jump around within a small amplitude. For example, if the average pressure was 7.2 psi, the pressure readings would jump within the range of 7.20±0.03 psi. As a result, the curve was not smooth enough. Nevertheless, the average value would be used for any further quantitative analysis.

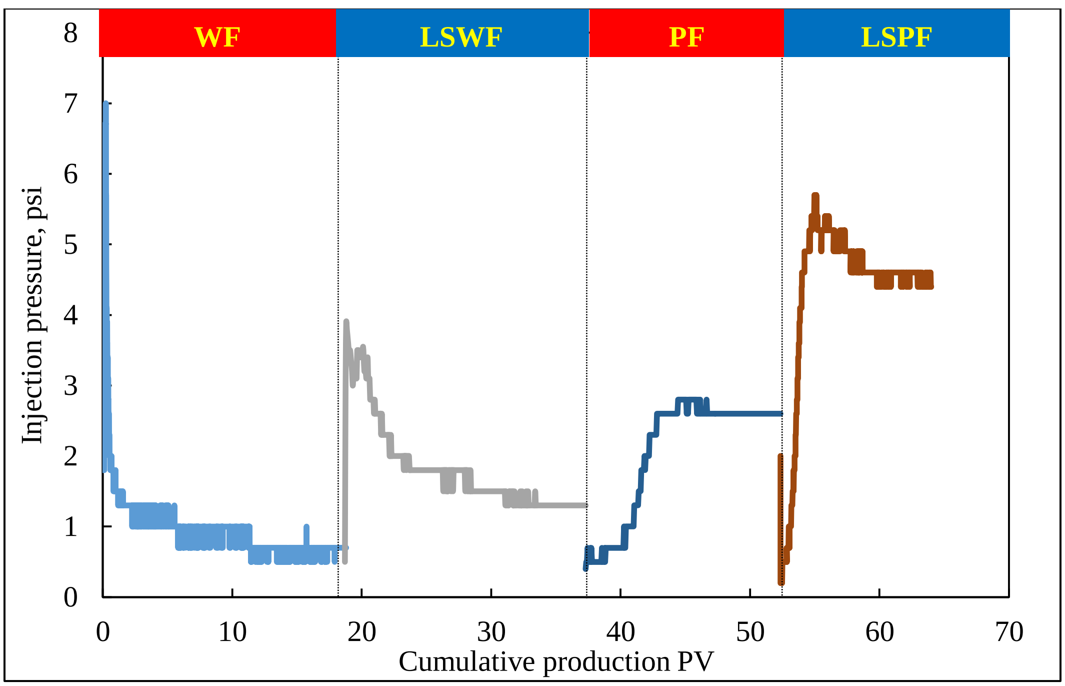

Figure 5.13 The pressure response (Exp. #NB-2)

The impact of the initial wettability of the sandpack cores on oil recovery performance was analyzed based on the comparison of the experimental results shown in Figure 5.11. The oil recovery efficiency by the initial waterflooding was much lower when the porous media was originally more oil-wet, while a higher oil recovery could be achieved if the porous media was originally more water-wet. The oil recovery by normal salinity waterflood was 37.8% and 61.9% for initially oil-wet and water-wet sandpack cores respectively.

The oil recovery factor after LSWF was 47.6% and 68.8%, respectively. The final oil recovery after water flood (including normal salinity water flood and low salinity water flood) and polymer flood (including normal salinity polymer flood and low salinity polymer flood) was lower if the porous media was originally more oil-wet (61.88% versus 76.2%). Nevertheless, the oil recovery improvement by low salinity water flood and low salinity polymer flood were more significant if the porous media was originally more oil-wet (8.71% versus 6.90% for LSWF, 7.94% versus 2.85% for LSPF). In the originally more oil-wet porous media, the water breakthrough was earlier than that in originally more water-wet porous media.

By combining these two technologies, injecting a low salinity polymer solution, the interests of both parties can be expanded. First, adding polymers to low-salinity floods can increase the sweeping efficiency and mobilize some of the oil separated by low-salinity brines, otherwise these oils will be trapped (Shaker Shiran 2013). Also, by supplementing the polymer solution with low salinity water, the low salinity effect can increase polymer flooding recovery by altering the wettability of the rock surface and releasing additional oil. (Vermolen et al., 2014)

5.3. EFFECT OF INJECTION SEQUENCE OF POLYMER SOLUTIONS

The purpose of this experiment was to investigate the effect of injection sequence of polymer with different salinities. The experimental setup is the same as above. After establishing a reasonable waterflooding residual oil saturation condition with extensive pore volumes of water injection, LSPF was performed followed with normal salinity polymer flooding (PF). The results were compared with the performance observed in the base case (Section 5.1).

The water cut behavior and oil recovery performance were shown in Figures 5.14 and 5.15. During the water flooding process, a water breakthrough was observed with the injection of 0.25 PV. After that, the water cut rose rapidly to 80%, and the injection amount was 0.6 PV. When the water cut was 80%, the recovery factor is 22%. The waterflooding continued until no more oil was produced, the oil recovery factor ended up at 40.18 and a total of 11.8 PVs of SFB was injected. Then in the LSWF, after the injection of 0.7 PVs of SIB, the water cut began to decrease and continued to rise after the lowest level of around 94%. The incremental oil recovery was 4.1% OOIP during this injection period, with an injection volume of 0.9 PV. The water cut remained above 98% afterward, and a total of 7.2 PVs of SIB was injected, resulting in a recovery factor of 50.6%, which was, though relatively lower, compared with the performance in the base case after waterflooding. The subsequent displacement was LSPF. After the injection of 1 PV of LSP, the water cut decreased to 93.5%. There was more oil produced, and 2.1% OOIP incremental oil was recovered. After further injection of LSP at 1.5 PV, the water cut was decreased even as low as to 82%. At this time, more oil was produced, and the incremental oil recovery was further increased by 5.3% OOIP. After that, the water cut climbed back up to above 98%. A total of 13 PVs of LSP was injected until no more oil was produced, and the oil recovery factor was increased to 71.15%. Almost no noticeable incremental oil was obtained from the following normal salinity polymer flooding.

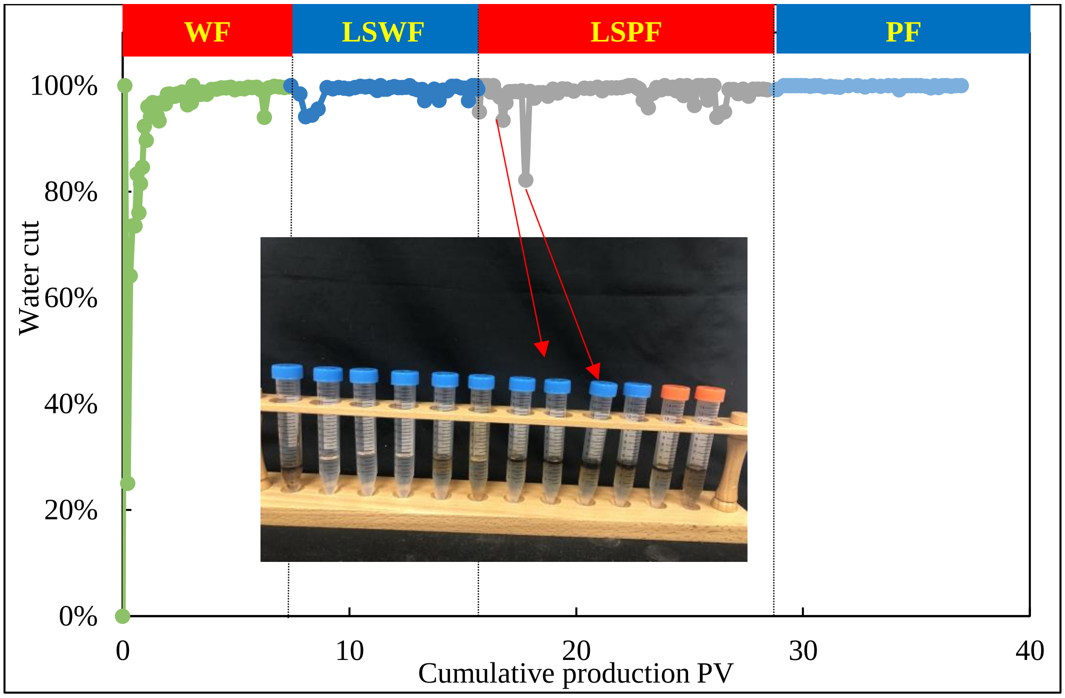

Figure 5.14 The water cut behavior (Exp. #NB-3)

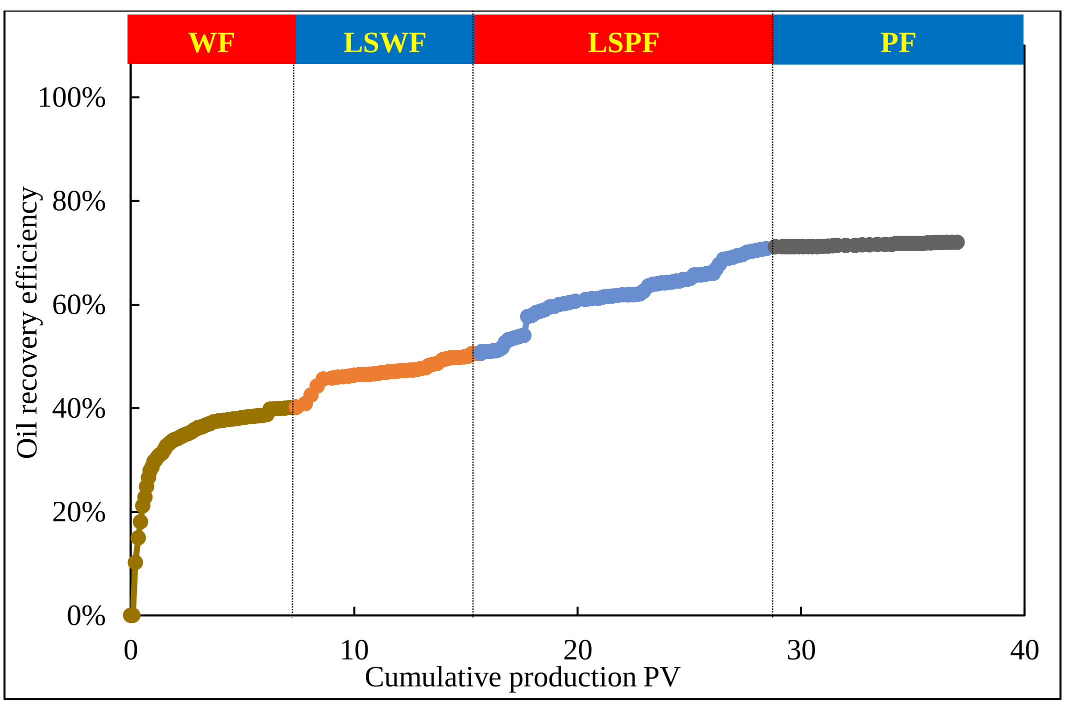

Figure 5.15 The oil recovery performance (Exp. #NB-3)

The oil saturation in the sand pack was reduced accordingly in the flooding process, as shown in Figure 5.16. In the WF process, the oil saturation was reduced from 0.896 to 0.536, and in the following LSWF the oil saturation was reduced to 0.443. During the LSPF the oil saturation significantly dropped to 0.259. No remarkable oil saturation reduction was observed during the PF.

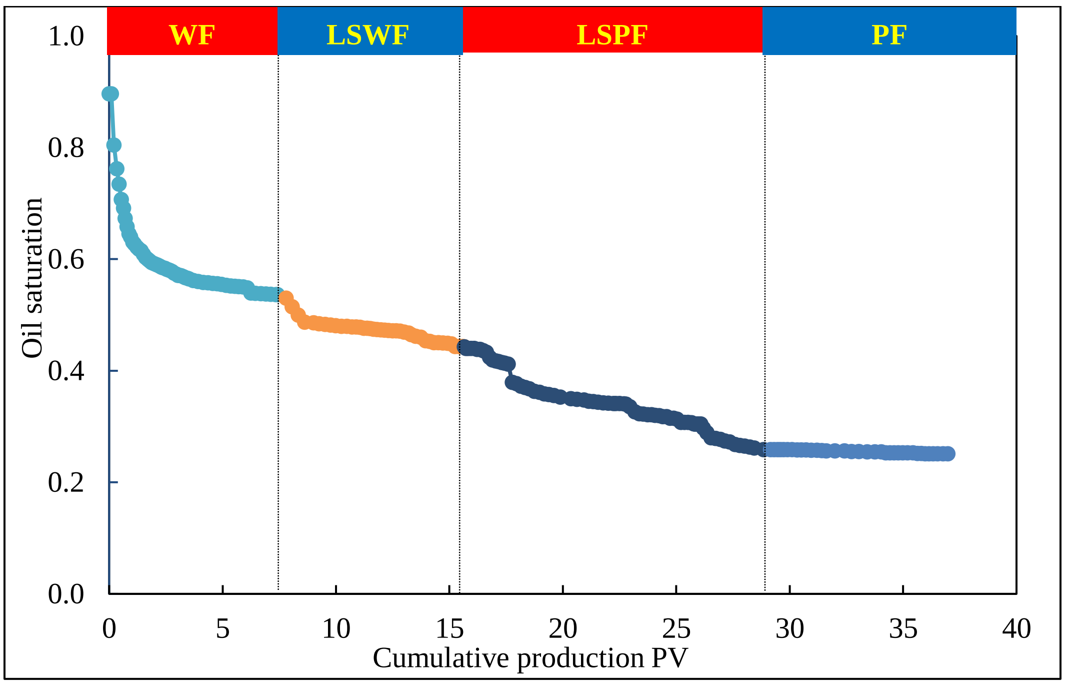

Figure 5.16 The average oil saturation in the sandpack (Exp. #NB-3)

As shown in Figure 5.17, it was observed that the injection pressure rose rapidly to 7.8 psi during the initial waterflooding process and then began to drop rapidly to 2.5 psi before stabilizing at 1.3psi. During the subsequent LSWF, the injection pressure rose slowly to 1.9 psi and then remained stable. The reason for this phenomenon may be clay swelling and fines migration due to the low salinity nature of the injected water. After switching to LSPF, the injection pressure rose rapidly at the beginning and peaked at 14 psi, then gradually dropped and stabilized at 10 psi. In the following PF process, the injection pressure finally stabilized at 5.6 psi.

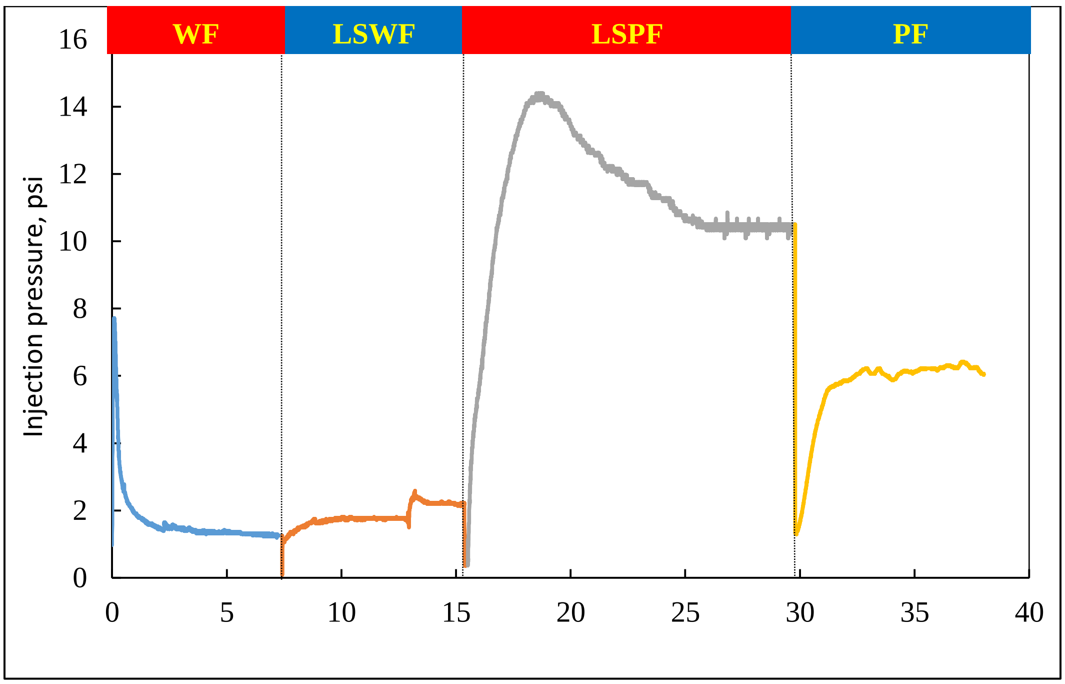

Figure 5.17 The pressure response (Exp. #NB-3)

The injection sequence of polymer with different salinities significantly influences the oil recovery performance. The influence is shown by comparing the two sandpack experiment results, as shown in Figure 5.18. The oil recovery performance of water flooding and low salinity water flooding was comparably similar, indicating the repeatability of the experiment. Higher recovery efficiency improvement was achieved when the low salinity polymer flood was performed before high salinity polymer flood (20.57% versus 4.55%).

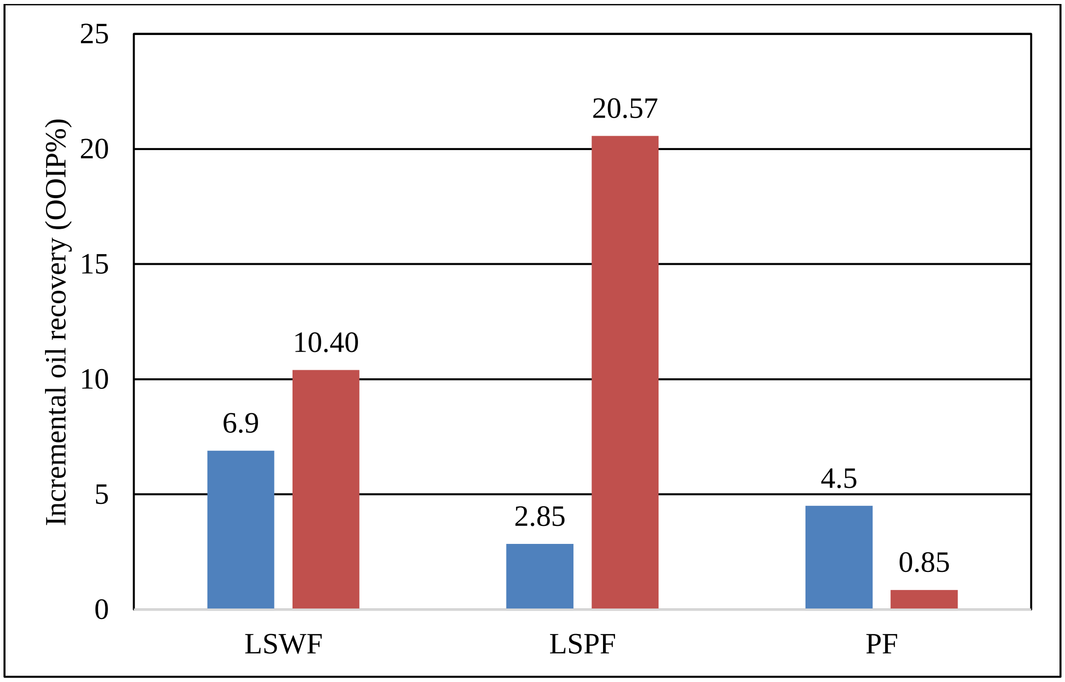

Figure 5.18 The comparation of incremental oil recovery of exp. #NB-1 and #NB-3

5.4. THE EFFECT OF STARTING TIME OF POLYMER FLOOD

In this section, the polymer flooding was started at the beginning, and no water flooding was performed. That is, the polymer flooding was implemented in a secondary recovery mode. By comparing the results with the cases in which waterflooding was performed before polymer flooding, the impact of the starting time of polymer flooding was demonstrated.

As shown in Figures 5.19 and 5.20, after direct injection of the polymer, as the polymer was much more viscous than water, the displacement would be more piston-like in the porous media. The displacement process was more stable and the polymer could displace the oil more efficiently. The water cut reached 80% after 0.8 PVs of injection, which was observed much later than in the cases initially starting with waterflooding. It indicates the polymer flooding can maintain a longer low-water-cut production period.

Meanwhile, the oil recovery factor was 46.94%, which was much higher compared with the case in which polymer flooding was implemented after extensive waterflooding. The polymer water cut was increased to 98% after a further injection of 1.8 PV, and the recovery factor was 65.56%. This performance was also much better than starting the polymer flooding very late. The ultimate oil recovery after 19.5 PVs of polymer injection was strikingly as high as 71.17%. After the injection of LSP, an incremental oil recovery of 5.72% OOIP was obtained.

The oil saturation in the sand pack was reduced accordingly in the flooding process, as shown in Figure 5.21. In the PF process, the oil saturation was reduced from 0.739 to 0.213, and in the following LSPF, the oil saturation was reduced to 0.171. Much higher recovery efficiency was achieved when started with polymer flood (~10% OOIP higher).

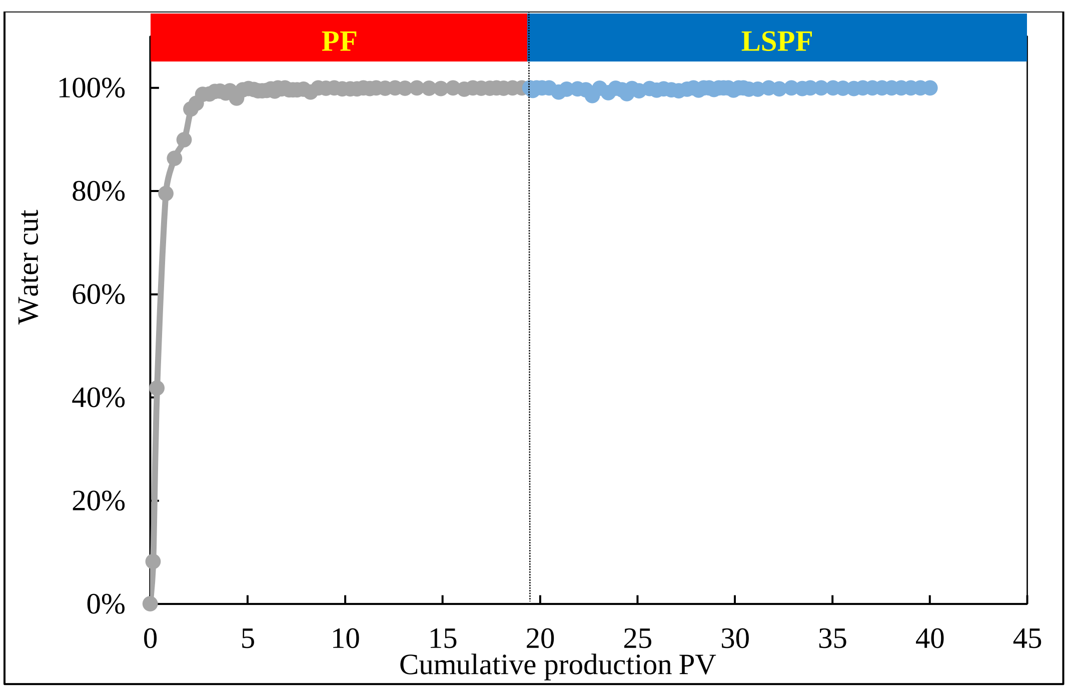

Figure 5.19 The water cut behavior (Exp. #NB-4)

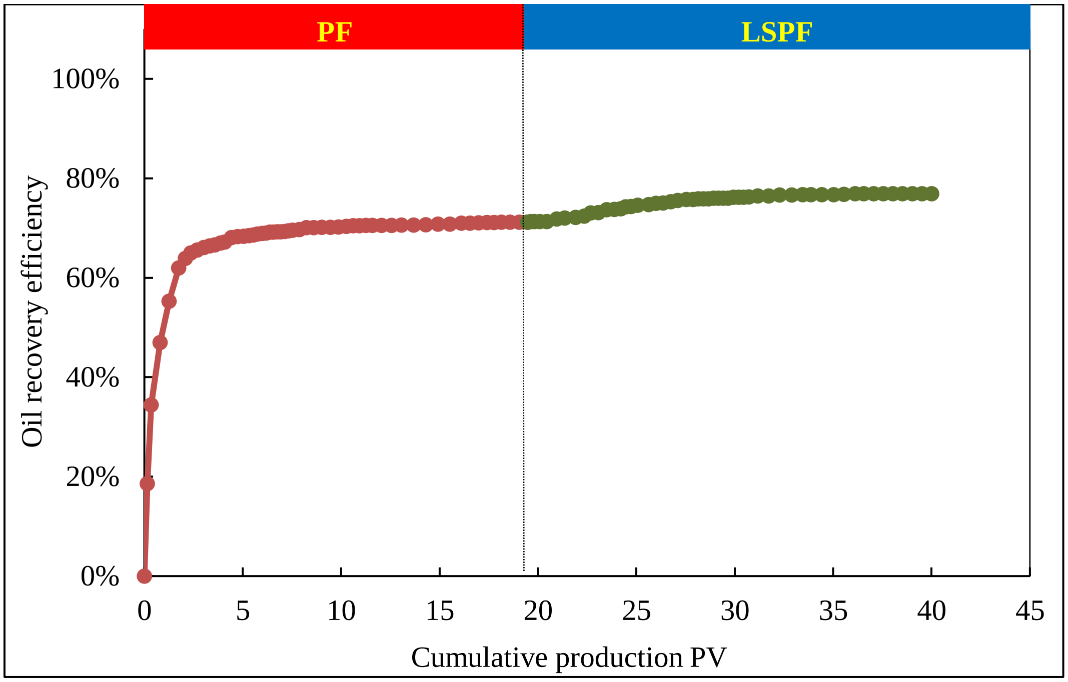

Figure 5.20 The oil recovery performance (Exp. #NB-4)

Compared with the tertiary low salinity flooding, the second low salinity flooding has a higher recovery factor, which may be due to the effective capture of oil clusters during the high salinity water injection process before the tertiary low salinity flooding. As the crude oil ages, the wettability of the core changes to a medium-humid state. Large pores may be lyophilic, and small pores may be hydrophilic. In the high salinity water injection process, the intrusive fluid first occupies smaller pores through the membrane flow, causing the oil content in the larger pores to peel off. This may limit the continuity of oil through the porous medium and increase the chance of oil capture. The polymer passes through "open flow" channels and pores, and the oil is passed by low salinity water. Without contact with the low-salinity water, it will prevent the low-salinity water from any reaction with the pore elements (pore throat and pore wall), thereby mobilizing the trapped oil. In the secondary mode, by maintaining the continuity of the membrane and allowing fewer shear events in a weaker water-wet, direct low salinity injection of oil movement can be achieved. At the same time, the multi-component ion exchange is performed together with the expanded bilayer membrane. (Shaker and Skauge 2013).

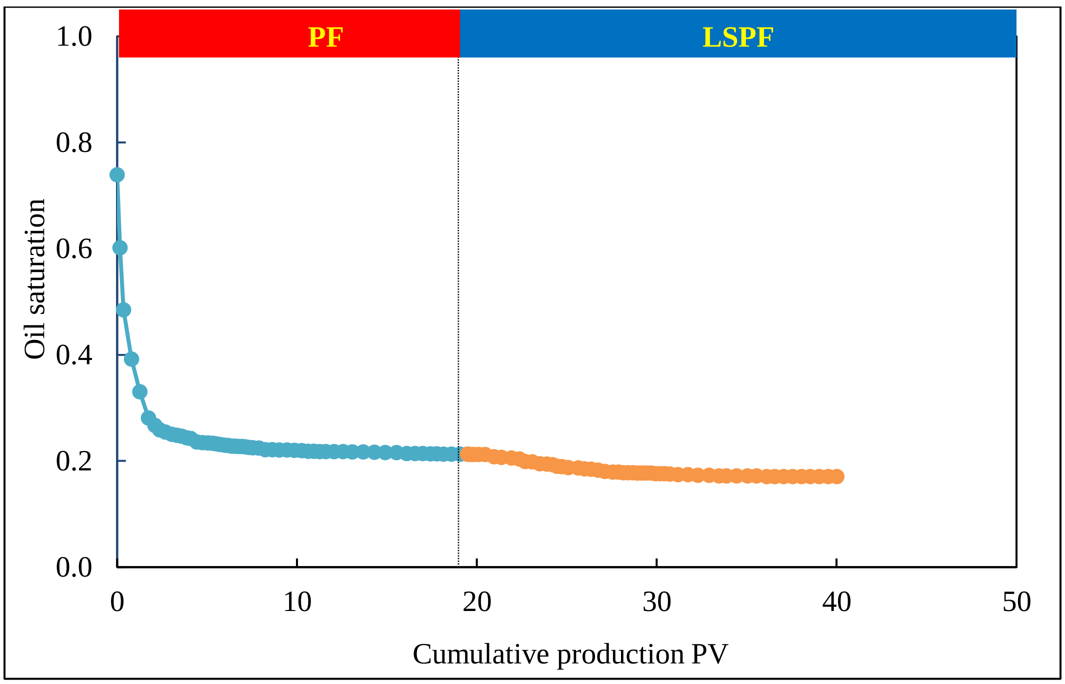

Figure 5.21 The average oil saturation in the sandpack (Exp. #NB-4)

5.5. SUMMARY

With all the sandpack flooding experiments, it has been demonstrated that low salinity waterflooding can recover more oil even after extensive normal salinity waterflooding. The low salinity polymer flooding can recover more oil (3-10% OOIP) even after extensive normal salinity waterflooding, low salinity waterflooding, and PF. Much higher recovery efficiency was achieved when starting with polymer flood (~10% OOIP higher). The wettability has a significant impact on the performance of initial waterflooding, oil recovery improvement by low salinity waterflooding and low salinity polymer flooding, and the overall oil recovery performance. The oil recovery efficiency by the initial waterflooding was much lower when the porous media was originally more oil-wet, while a higher oil recovery could be achieved if the porous media was originally more water-wet. The final oil recovery after water flood (including normal salinity water flooding and low salinity water flooding) and polymer flooding (including normal salinity polymer flooding and low salinity polymer flooding) was lower if the porous media was originally more oil-wet (61.88% versus 66.7% in this study). Nevertheless, the oil recovery improvement by low salinity waterflooding and low salinity polymer flooding were more significant if the porous media was originally more oil-wet (8.71% versus 6.90% for LSWF, 7.94% versus 2.85% for LSPF). The injection sequence of polymer with different salinities significantly influences the oil recovery performance. Higher recovery efficiency improvement was achieved when the low salinity polymer flooding was performed before normal salinity polymer flooding (20.57% versus 4.55%).

Figure 5.22 shows J-28 started production data before and after the polymerization. The water cut decreased from about 70% to 45% in 2 months, then slowly increased to about 60%, but recently dropped to about 50% in June 2019. Because the total amount of polymer solution injected into the reservoir is still less than 4% of the total pore volume of water flood development, it is too early to quantify the incremental oil production caused by polymer injection. The oilfield hopes to determine increased recovery after injecting a 10-12% polymer solution (Ning et al., 2019). The performance in the field was very similar to the laboratory results, in that polymer injection reduces the water cut and increases the recovery factor.

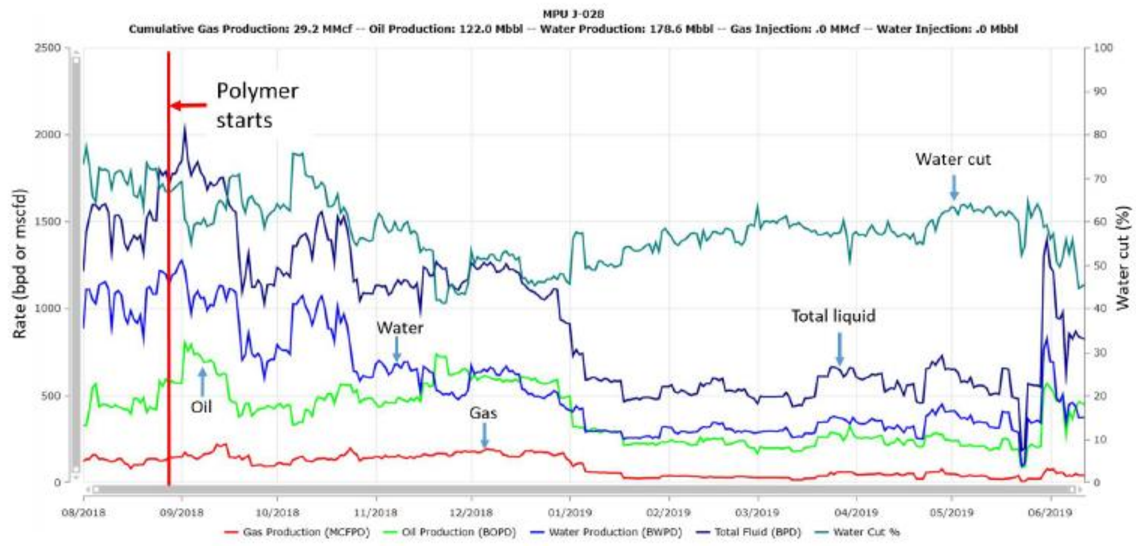

Figure 5.22 J-28 production response (From Ning et al., 2019)

6. CONCLUSIONS AND RECOMMENDATIONS

6.1. CONCLUSIONS

Based on the experimental results in this study, the main findings can be summaried as follows:

(1) The results of the tracer test proved that a wet-packed sandpack would distribute the sand more evenly, resulting in a homogeneous sandpack.

(2) Low salinity water would effectively increase the displacement efficiency both in silica sandpack and NB formation sandpack. Low salinity water has increased oil recovery in the range of between 6% and 8%.

(3) When water with normal salinity is used as the initial water flood, the average water breakthrough is around 0.3 PVs. If the low salinity water is used for the initial water flood, the water breakthrough is delayed by about 0.2 PV. The use of original sand, which was more oil-wet, can lead to the water breakthrough about 0.1 PVs earlier.

(4) Further lowering the salinity of the low salinity water and removing the divalent cations in the low salinity water cannot significantly improve the oil recovery performance.

(5) Low salinity polymer and normal salinity polymer are both effective in EOR, and the low salinity polymer is even more effective, increasing oil recovery by 3-20% depending on the injection sequence.

(6) Compared with the normal salinity polymer, the low salinity polymer can be more effective to reduce the water cut, and can make the process for a longer time.

(7) Changed in wettability of sand and polymer injection sequence will affect the recovery factor. The use of clean sand and earlier injection of the low salinity polymer will increase oil production.

(8) The viscosity of the effluent was less than that of the original polymer injected, which demonstrated that polymer degradation during displacement affected EOR.

6.2. RECOMMENDATIONS

Though a series of experiments have been carried out, interesting results were observed in this study, and the remarkable oil recovery improvement from low salinity water/polymer flooding compared with a higher-salinity flooding was preliminarily demonstrated with both commonly used silica sand and specific formation sand from a target heavy oil reservoir, due to the time limit, this study is still insufficient to provide a thorough understanding of the low salinity water/polymer flooding in enhancing heavy oil recovery. The following considerations are recommended for future studies.

(1) Check emulsion in the effluent, which could be a mechanism to contribute to the improved oil recovery performance from low salinity waterflooding and low salinity polymer flooding.

(2) Ion exchange may occur after switching to low salinity water/polymer flooding from normal salinity water/polymer flooding. The ion exchange may induce property change of the pore surface (e.g. wettability alteration) and contribute to the incremental oil recovery. Study of the ion exchange behavior can lead to a better understanding of the low salinity water/polymer flooding.

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