Oil displacement by polymer flooding in the Uzen Field

By

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Statement of originality

This is to confirm that the material of this project is, to the best of our knowledge, our original work. We declare that this project's intellectual substance is entirely our own creation and that all sources used in its preparation have been properly cited.

Abstract

Primary recovery is the production of the hydrocarbons under the natural energy of the reservoir. As the reservoir energy depletes and pressure reduces, production also declines. Secondary recovery methods such as water and gas injection are typically applied after the decline in production has been noticed. When the production of hydrocarbons is not enough, tertiary recovery methods are applied. Chemical flooding is one of the most used techniques to maintain oil production, especially polymer flooding. Polymers are applied to the reservoirs with high water cut since polymers are effective in increasing the sweep efficiency and mobility control. By adding more viscous fluid such as polymer to the water, water becomes more viscous and is able to move more oil from the injection well towards the production one. One of the Kazakhstan fields, where the water cut is very high, is the Uzen field. That is why polymer flooding has been considered for this field. In previous studies, screening of four types of polymers has been completed, after which Polymer 3 solution with a concentration of 2500 ppm was established to be the most suitable for this field. In this paper, Polymer 3 then has been further tested with different kinds of water - Caspian seawater and Alb water (water from Albian age layer) - to study its behavior when injected into the Uzen core sample to displace oil. The results of the oil displacement tests conducted through the Core Flooding System (CFS-700) have shown that polymer prepared with Caspian seawater works better than polymer prepared with Alb water in terms of oil recovery, injectivity, and resistivity factors. The next step of the research is to conduct pilot tests in the field and monitor the polymer behavior in real conditions.

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Chapter 1

1.1. Introduction

When the primary drive mechanism is not enough to maintain optimum reservoir pressure to produce oil, the secondary drive mechanism is applied by injecting gas or water. Waterflooding can increase oil recovery by 15% to 35%. The effectiveness of the waterflooding process highly depends on the situation and specific properties of the field such as rock characteristics, oil properties, and mobility ratio. The latter is especially important to evaluate the effectiveness of water injection so that the effectiveness increases as the mobility ratio decreases. Indeed, an increase in mobility ratio is a big challenge when injected water reaches the breakthrough, and oil production rapidly slows down. To prevent such problems, chemical EOR methods can be applied.

Polymer flooding is one of the most frequently used chemical EOR techniques, which is often applied to decrease the water-oil mobility, and in this way, increase the effectiveness of the waterflooding process. This EOR method is used to increase sweep efficiency and decrease the mobility ratio. Polymer works as a way to increase the water viscosity and maintain uniform movement of water in the formation. In this way, water occupies most of the reservoir space and pushes more oil to the production well in cases when the reservoir is heterogeneous and the injected water, in the absence of polymer, moves preferably in the path of high permeability. Moreover, reservoirs with high-viscosity oil also challenge the uniform movement of water, which usually results in the bypass of water through oil (fingering). In this regard, polymer flooding increases the areal sweep of water, and so increases the oil recovery. As a result reduction in produced Water Oil Ratio and an increase in oil production are observed.

1.1.1. Research Problem

Such polymer flooding is to be done in the Uzen field located in the West Kazakhstan region. The field was discovered in 1961 and has an estimated reserve of 8.4 billion barrels of initial oil in place. The main features of the field include a high concentration of wax and moderately high oil viscosity. The current situation of the Uzen field states high water cut and ineffectiveness of applied waterflooding. Polymer flooding in other fields similar in properties to the Uzen field showed success and increased the production of oil significantly. Nevertheless, for the successful implementation of the polymer injection in the given field, proper analysis and screening should be completed.

In this project, the polymer performance of the selected polymer in the porous media through the set of core flooding tests is going to be studied.

1.1.2. Research Objectives

The aim of this paper is to evaluate the oil displacement in the Uzen field if the chemical EOR method will be applied. The evaluation is done by conducting a series of core flooding experiments with polymer and Uzen cores. Such a series of experiments will provide relative permeability characteristics, chemical-rock compatibility data, injection capabilities, and saturation changes after water and chemical flooding tests. Based on the results suitable polymer and its optimum concentration can be selected for the Uzen field to minimize the water-cut, resume the efficiency of water injection and increase the oil production.

Objectives:

- To conduct oil displacement tests through core flooding with polymer 3 by the use of synthetic brine, seawater, formation water, and oil;
- To evaluate the recovery factor of the oil after the polymer flooding;
- To analyze results and identify the best working polymer.

1.1.3. Justification of the Research

The study on polymer screening has been already conducted for the given field to find an optimum polymer and its concentration. Initially, there were 4 polymers, which had to be analyzed by conducting rheology, thermal stability, and static adsorption tests. Based on the obtained results, the most optimal candidate was selected to be Polymer 3 with a concentration of 2500 ppm. However, further research should be done to develop the experiments and get more accurate results. For the analogous Mangala Field in India, a set of experiments were completed to apply polymer injection. The field is considered waxy containing moderately viscous oil. Taking into account these features, high waterflood mobility ratio, and other screening criteria of the field, polymer flooding was chosen to be implemented. The results of experiments completed beforehand, confirmed the field to be an excellent candidate for the chemical EOR method with an incremental polymer flooding of about 30% above waterflood. Those experiments were based on adsorption and interfacial tension measurements.

Chapter 2

2.1. Literature Review

2.1.1. EOR Methods

At the initial stage of production in the field, oil is produced under high reservoir pressure. Such a process is called primary oil extraction. Primary drive mechanisms such as water drive, gas-cap drive, solution-gas drive, and gravity drive, keep the reservoir pressure high (Smithson, 2016). Usually, during the primary oil extraction, 5-20% of the total hydrocarbons from the reservoir can be recovered (Ragab and Mansour, 2021). At a certain point in time, the oil extraction slows down due to the fact that the natural energy of the reservoir is not enough, and the primary drive mechanisms start to become weak to push hydrocarbons to the surface. When the production rate decreases and goes down beyond the optimum range of production, the secondary stage of driving mechanisms are to be introduced. Secondary recovery is when gas or water is injected to sustain reservoir pressure in the optimum range. Secondary oil extraction methods are used to increase the production of oil. Water or gas is injected into the reservoir through the injection wells to increase the reservoir pressure and maintain it at high levels. Additional recovery of 15–35% is achieved after applying secondary oil recovery methods (Qisheng and Yongchun, 2023). However, due to the current increase in the demand of oil on the global market, more oil is needed to be supplied and produced. That is why tertiary oil recovery methods are applied if primary and secondary oil recovery methods are not enough to sustain sufficient oil production rates.

When secondary recovery methods start to lose their efficiency, further techniques such as tertiary oil recovery should be used (Nolan, 2010). That is why tertiary methods are mostly applied in mature oil fields (Maricic et al, 2014). Tertiary oil recovery or enhanced oil recovery (EOR) methods target immobile oil reserves, which cannot be produced by primary or secondary recovery methods (Denney, 2012). EOR methods are applied to increment the production of oil from a reservoir and prolong the reservoir's life and profitability. EOR methods are divided into four groups: thermal, gas injection, chemical, and microbial. Figure 1 shows the EOR techniques classification (Muriel et al., 2020).

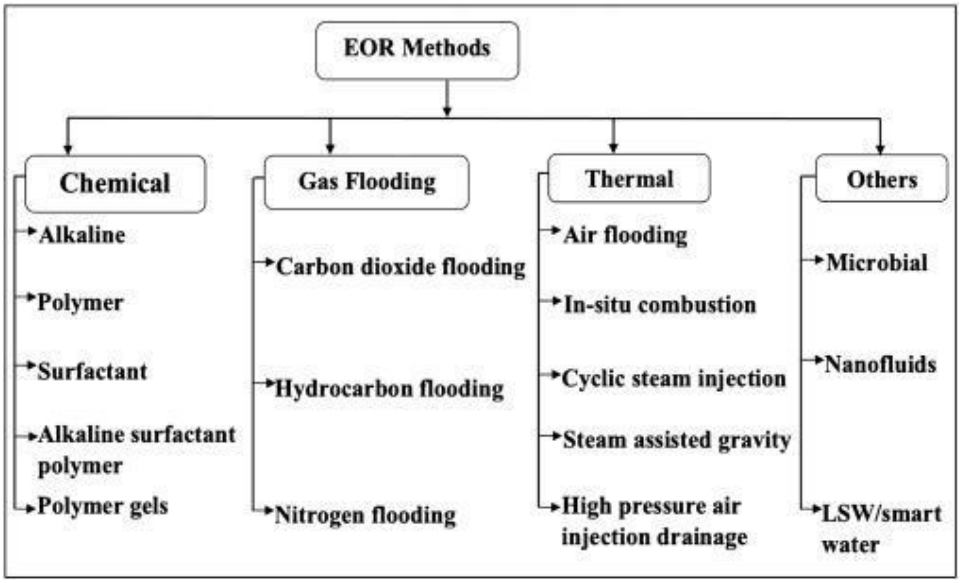

Figure 1. EOR methods classification (Alfarge et al., 2020)

Despite the fact that all these methods aim to increase oil recovery, not all of them can be implemented on a field. Each field has its unique reservoir properties including lithology, physical and chemical properties, rock and fluid properties, etc. That is why choosing the most suitable EOR method based on these properties is a complex and difficult task, which should result in the highest possible recovery for the field (Baghir et al., 2016).

In many fields around the world, chemical EOR techniques are applied. Because of its superior efficiency, technical and economic viability, and affordable capital cost, the chemical EOR method, a non-thermal EOR approach, has been deemed the most promising of all EOR procedures (Levitt and Pope, 2008). A tertiary recovery stage called chemical EOR flooding can significantly increase oil recovery from water-flooded reservoirs (Khanifar et al., 2021). Chemical EOR techniques improve oil recovery by improving how well water is fed into the reservoir to replace the oil. Depending on the type of chemical EOR process used, chemicals added to the water slug change how fluids interact with one another and/or with rocks in the reservoir. This includes reducing the interfacial tension between the imbibing fluid (Ali et al., 2018) and the oil or increasing the injectant's viscosity to reduce mobility and conformity control (Taborda et al., 2017). Additionally, the chemicals are injected to change the rock's wettability and increase oil permeability (Sun et al., 2017).

The chemical EOR method is any technique, where chemicals are added to the injection fluid (Gbadamosi, 2019). Based on the chemical components and combinations of these components, different chemical EOR methods can be applied such as polymer flooding, surfactant flooding, alkaline-surfactant (AS) flooding, alkaline-surfactant-polymer (ASP) flooding, nanoparticle flooding, and low salinity water injection (LSWI) (Muriel et al., 2020). According to studies on EOR, chemical EOR is applied in 11% of all EOR projects worldwide. More than 77% of all chemical EOR methods come for polymer flooding. (Rellegadla et al., 2017).

Chemical EOR may involve modifying the deep-formation profile utilizing a polymer, surfactant, alkaline, emulsion, or a combination of them (Gbadamosi, 2022). Water flooding, in which water is injected into the injection well to force the oil into a production well, is one of the first options to increase oil recovery. Oil and water, on the other hand, are immiscible fluids, which means they don't mix. Low water viscosity and significant heterogeneity in the reservoir cause injected water to reach the production well but leave some oil in the reservoir (Firozjaii and Saghafi, 2019). In addition to increasing mobility control, the addition of water-soluble polymers will make the water viscous, which could also result in a reduction in water's relative permeability to oil.

There are many high water cut reservoirs throughout the world. Costs climb as the oil-to-water ratio does. High-water-cut oil fields need to have their high water consumption reduced, their economic benefits improved, and their oil recovery increased (Xue et al., 2023). In addition to shortening the oil and gas wells' useful lives, water production also contributes to a number of other issues, such as hydrostatic loading, tubular corrosion, and fines migration.

Depending on the reservoir rock and fluid characteristics, an appropriate chemical EOR method may be used. For many mature fields, the main challenge is high water production during oil and gas recovery. When the water/oil ratio needs to be decreased, the appropriate choice would be polymer flooding. Polymer flooding increases oil recovery by adding polymer solutions to increase the viscosity of the displacing water, which results in a lower water/oil ratio (Mandal, 2015). However, polymer flooding increases oil recovery not solely through the decrease in water/oil ratio, but also through the effect on fractional flow, and by pushing water from swept zones (Speight, 2013). Thus, this chemical EOR method is usually applied to reservoirs, which have certain conditions that reduce the efficiency of water flooding.

The primary result of the polymer is an increase in the water-oil mobility ratio, which can be estimated as the ratio of the mobility of the displacing phase to the mobility of the displacement phase (Ragab and Mansour, 2021). An example of such conditions is water injection into reservoirs containing heavy oil. In such cases, water can bypass oil causing a phenomenon called “fingering”. This process is controlled by the mobility ratio, which is defined as the following equation:

$$M = \frac{\left(\frac{k_{rD}}{\mu_D}\right)_{S_D}}{\left(\frac{k_{rd}}{\mu_d}\right)_{S_d}}, \tag{1}$$

, where

k_{rD} - displacing phase’s relative permeability;

μ_D - displacing phase’s viscosity;

k_{rd} - displaced phase’s relative permeability;

μ_d - displaced phase’s viscosity;

S_D- displacing phase saturation behind the displacing phase front;

S_d - displaced phase saturation before the displacing phase front.

In case when M >1, the sweep efficiency is low, displacement is unfavorable and results in fingering, meanwhile, when M ≤1, the sweep is high and displacement is favorable. This difference is schematically represented in Figure 2. That is why polymer is commonly used as the mobility control agent, which reduces mobility ratio by increasing the viscosity of displacing phase i.e. water.

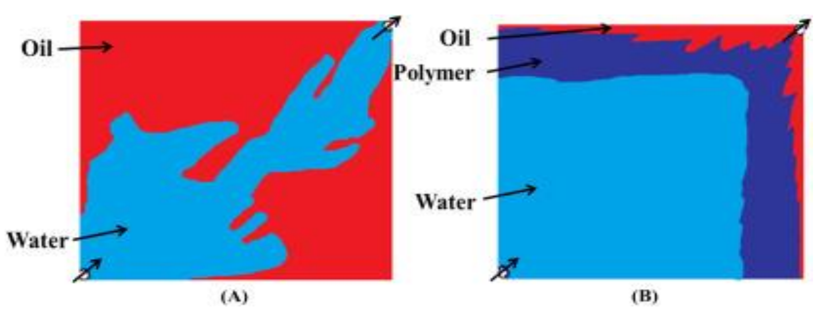

Figure 2. Mobility control schematic (A) Before polymer injection M >1; (B) After polymer injection M ≤1. (Li et al., 2021)

Despite the fact that polymer flooding is one of the well-working EOR techniques, which can increase productivity up to 30%, there are several key factors that should be considered before the application of polymer injection. The efficiency of this technique is highly dependent on the properties like the temperature of the reservoir, oil viscosity, pH, contamination, and salinity of the brine.

Another application of polymer is to block high permeable areas and control coning (Figure 3). Such application is especially effective in high permeability zones and fractures that can channel or make water incline from the targeted pathway. Meanwhile, the injection of polymer-gel can shut off high permeability regions of the reservoir, and induce higher coverage of rock for water movement (Bai et al., 2015). In the research conducted by Bedaiwi et al. (2009), the permeability alteration principle was used by injecting polymer gel to carry out the water treatment process. The Berea sandstone, which is characterized by the existence of channels, was used to test the permeability modification technique. As a result of the experiment, a permeability reduction from 4500 mD to about 15 mD was successfully achieved, showing the effectiveness of polymer gel.

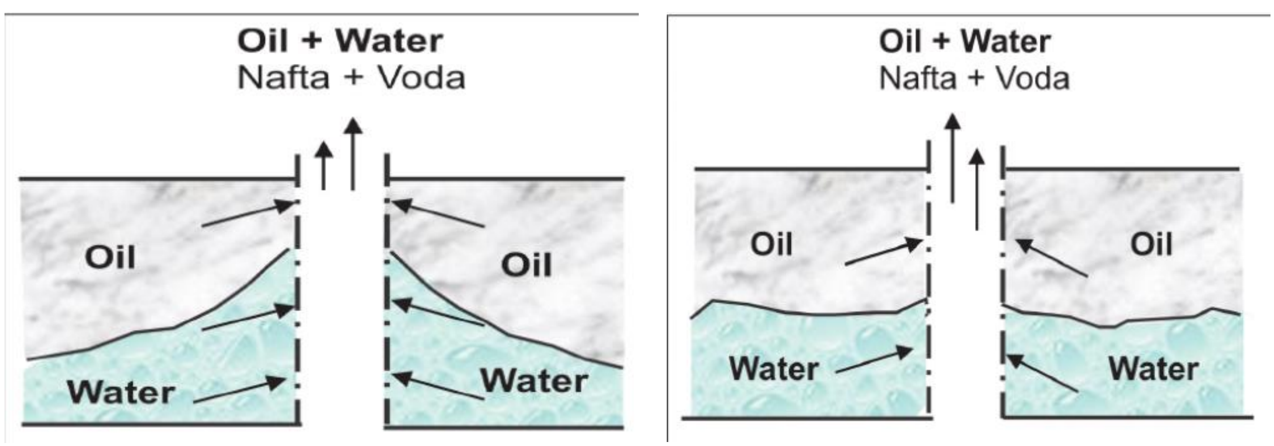

Figure 3. Water conning before (left) and after (right) treatment (Bedaiwi et al., 2009)

There are different types of polymers used in the flooding process. Biopolymers and synthetic polymers are the two most common categories of water-soluble polymers (Sheng et al., 2015). There are different types of biopolymers used in polymer floodings such as scleroglucan, carboxymethylcellulose, welan gum, and guar gum, however, Xanthan gum, or simply Xanthan, is the most common biopolymer used in the industry. A non-ionic biopolymer called xanthan has been employed in drilling mud and polymer flooding, among other oil industry applications. Xanthan, the structure of which is shown in Figure 4, is a non-ionic biopolymer, which makes this polymer type maintain its viscosity under conditions of high salinity, however at lower salinities or in deionized water Xanthan viscosity becomes lower than synthetic polymers' (Kamal et al., 2015).

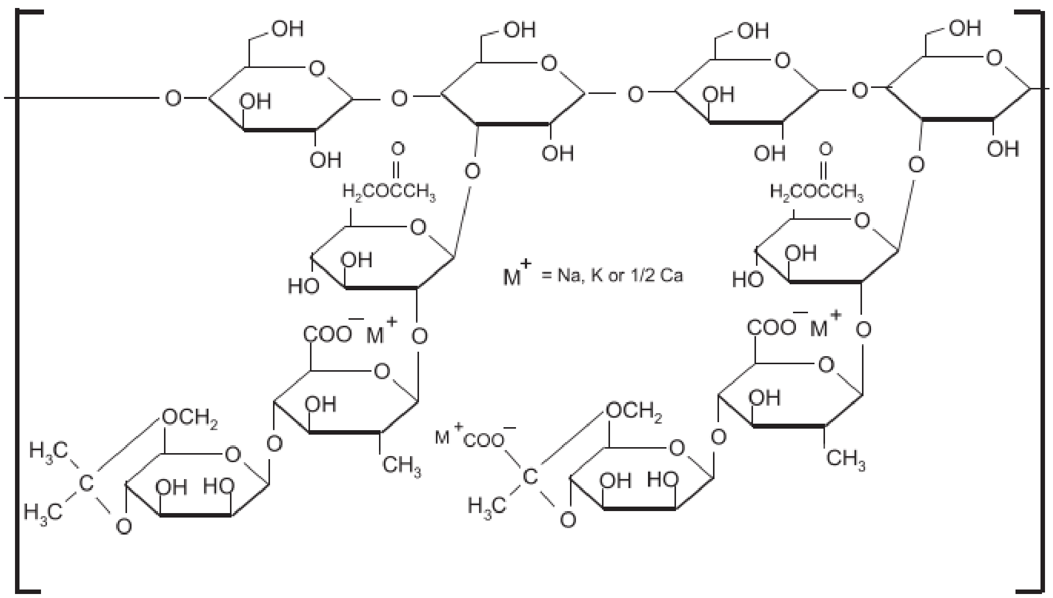

Figure 4. Xanthan structure (Olajire, 2014)

One of the most common representatives of synthetic polymers is partially hydrolyzed polyacrylamide (HPAM). HPAM is a water-soluble, synthetic straight-chain polymer used in EOR applications. It is a copolymer of polyacrylamide and polyacrylic acid obtained by the partial hydrolysis of polyacrylamide or by copolymerization of sodium acrylate with acrylamide (Olajire, 2014). HPAM is used in most polymer flooding processes at both field and experiment scales. HPAM structure is shown in Figure 5. HPAM is a low-cost polymer, which maintains its viscosity in low salinity.

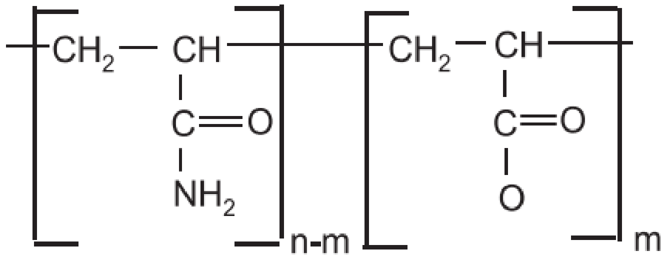

Figure 5. HPAM structure (Olajire, 2014)

The first step in assessing prospective EOR strategies for candidate reservoirs is to apply screening criteria. Because most EOR projects need considerable financial capital inputs and might have serious unfavorable implications if they fail, screening criteria are crucial at the beginning of an EOR project (Hite 2004). With the development of EOR methods and world-spread application experience, several EOR screening criteria tables have been developed. By now the commonly used screening criteria were developed by Tabler et al. (1997) and Sheng (2015) and is presented in Table 1.

Table 1. Screening criteria for EOR techniques (Tabler et al., 1997 & Sheng, 2015)

		Oil Properties			Reservoir Characteristics					
Detail Table in Ref. 16	EOR Method	Gravity (°API)	Viscosity (cp)	Composition	Oil Saturation (% PV)	Formation Type	Net Thickness (ft)	Average Permeability (md)	Depth (ft)	Temperature (°F)
Gas Injection Methods (Miscible)										
1	Nitrogen and flue gas	> 35 ↗ 48 ↗	< 0.4 ↘ 0.2 ↘	High percent of C_1 to C_7	> 40 ↗ 75 ↗	Sandstone or carbonate	Thin unless dipping	NC	> 6,000	NC
2	Hydrocarbon	>23 ↗ 41 ↗	< 3 ↘ 0.5 ↘	High percent of C_2 to C_7	> 30 ↗ 80 ↗	Sandstone or carbonate	Thin unless dipping	NC	> 4,000	NC
3	CO_2	> 22 ↗ 36 ↗ [a]	< 10 ↘ 1.5 ↘	High percent of C_5 to C_{12}	> 20 ↗ 55 ↗	Sandstone or carbonate	Wide range	NC	> 2,500[a]	NC
1–3	Immiscible gases	> 12	< 600	NC	> 35 ↗ 70 ↗	NC	NC if dipping and/or good vertical permeability	NC	> 1,800	NC
(Enhanced) Waterflooding										
4	Micellar/ Polymer, ASP, and Alkaline Flooding	> 20 ↗ 35 ↗	< 35 ↘ 13 ↘	Light, intermediate, some organic acids for alkaline floods	> 35 ↗ 53 ↗	Sandstone preferred	NC	> 10 ↗ 450 ↗	> 9,000 ↘ 3,250	> 200 ↘ 80
5	Polymer Flooding	> 15	< 150, > 10	NC	> 50 ↗ 80 ↗	Sandstone preferred	NC	> 10 ↗ 800 ↗ [b]	< 9,000	> 200 ↘ 140
Thermal/Mechanical										
6	Combustion	> 10 ↗ 16 → ?	< 5,000 ↓ 1,200	Some asphaltic components	> 50 ↗ 72 ↗	High-porosity sand/ sandstone	> 10	> 50 [c]	<11,500 ↘ 3,500	> 100 ↗ 135
7	Steam	> 8 to 13.5 → ?	< 200,000 ↓ 4,700	NC	> 40 ↗ 66 ↗	High-porosity sand/ sandstone	> 20	>200 ↗ 2,540 ↗ [d]	< 4,500 ↘ 1,500	NC
—	Surface mining	7 to 11	Zero cold flow	NC	>8 wt% sand	Mineable tar sand	> 10 [e]	NC	> 3 : 1 overburden to sand ratio	NC

NC = not critical.
Underlined values represent the approximate mean or average for current field projects.
[a] See Table 3 of Ref. 16.
[b] > 3md from some carbonate reservoirs if the intent is to sweep only the fracture system.
[c] Transmissibility > 20 md-ft/cp
[d] Transmissibility > 50 md-ft/cp
[e] See depth.

A specific field's oil qualities and reservoir parameters, such as the oil's viscosity, gravity, saturation, porosity, permeability, depth, and temperature are the main parameters in the determination whether a polymer-flooding project is successful. Political, technical, and/or economic factors may all play a role in a polymer flooding project's failure. The technical causes include but are not limited to, the following: the lack of polymer, the polymer's resistance to formation water salinity and hardness, the inadequate size of the polymer slug, reservoir heterogeneity (i.e. unexpected channeling), injectivity issues, and environmental control (Saleh et al., 2014).

Ameli et al. (2021) conducted one of the latest studies on the screening criteria for polymer selection. They indicate that for a polymer to be efficiently working in the reservoir, it should have appropriate rheological, and adsorption properties, and proper shear and thermal stability indexes. For that purpose, a set of tests should be carried out to make an appropriate polymer screening.

Reservoir temperature and salinity affect the polymer viscosity and stability. It is reported that viscosity may decrease up to 50% in half a year at reservoir conditions (Ameli et al., 2021). So, the degradation of the polymer at the reservoir condition under thermal and mechanical stresses should be measured and analyzed. Polymer adsorption in the porous media also affects the actual concentration of the polymer during flooding. Hence, static and dynamic adsorption tests are required to select the best polymer (Xin et al., 2018). Shear thinning non-Newtonian behavior shown in Figure 6 is preferable for polymers for easier injection through the well. Hence, injectivity tests should also be conducted to select the polymer.

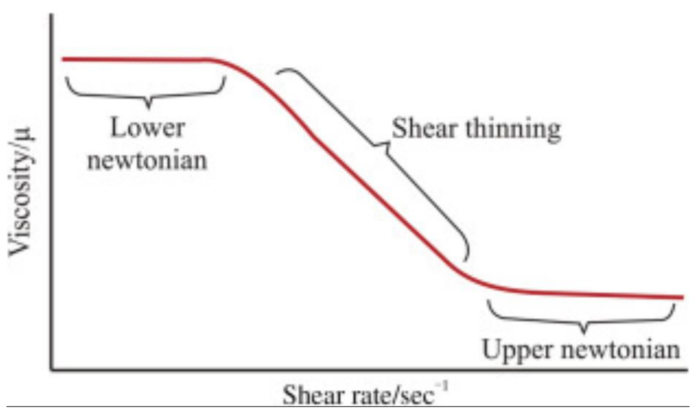

Figure 6. Shear thinning (Muhammed, 2020)

To sum up, it becomes clear that the screening of the polymer is important as it should be effective at the reservoir condition. Consequently, the main stage of any chemical flooding project is the polymer screening which consists of several tests such as thermal and mechanical stability tests, rheologic, injectivity and adsorption test, and oil recovery evaluation.

2.1.2. The Uzen Field

Currently Kazakhstan, like many other countries, is struggling with a low oil recovery factor, which is less than 30% (Kudaibergenov, 2015). That is why the use of EOR methods is a common practice in Kazakhstan fields. The summary of EOR methods applied in Kazakhstan fields is represented in Figure 7 (Bealessio et al., 2020).

Field	EOR Method	Application	Current Status
Uzen	Hot water injection	Full Field	Mature/Decline
Kenkiyak	Steam flooding	Full Field/Pilot	Active
Karazhanbas	Steam flooding & ISC	Full Field	Mature/Decline
Kalamkas	Polymer flooding	Pilot	Mature/Decline
Kashagan	Sour gas injection	First Phase	Active
Tengiz	Sour gas injection	First Phase	Active

Figure 7. EOR methods applied in Kazakhstan fields (Bealessio et al., 2020)

The only field where polymer flooding is being used now is the Kalamkas field. Other fields are using hot water, sour gas, steam flooding, and ISC (in-situ combustion) EOR methods. Uzen field is recently considered a candidate for polymer flooding.

The Uzen field is located 150 kilometers east of the Caspian Sea in western Kazakhstan on the Mangyshlak peninsula (Figure 8). The field was found to be heavily faulted and multi-layered when it was first discovered in 1961, with production being spread across 23 horizons at depths between 360 m and 2,200 m.

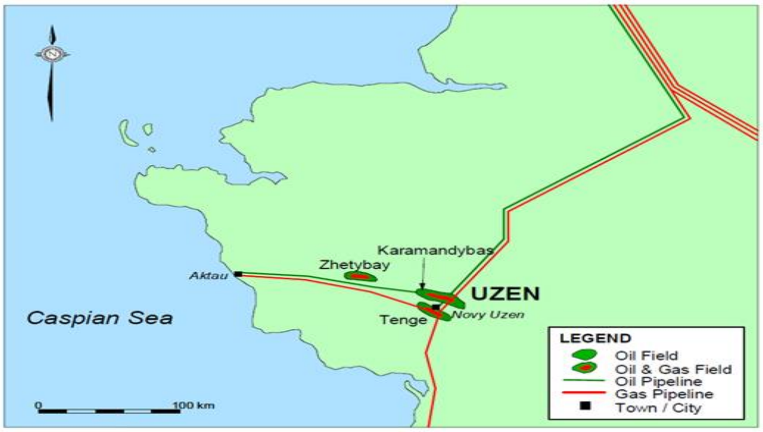

Figure 8. Location of the Uzen field (Sparke et al., 2005)

Table 2 (Bealessio et al., 2020) shows the reservoir rock and fluid properties of the Uzen field.

Table 2. The reservoir rock and fluid properties of Uzen field (Bealessio et al., 2020)

Parameter	**Uzen Field**
Crude Oil Components and Characteristics	10-25% Paraffins at 30° C Pour Point
Viscosity, cP	3.5-4.2
Density, °API	35
P_{res}, MPa	15-18 @ 54-69 °C
P_b, Mpa	8.3-11.2 @ 60-70 °C
Lithology	Sandstone, ISB&M
Thickness, m	10-30 per zone
Depth, m	360-2,200
Porosity, fraction	21-25%
Permeability, mD	200-1,000
Oil in Place, MMBO	8,400

S_{oi}, %	63-70%
S_{wi}, %	30-37%
Water Aquifer	-
Productive horizons	23
High Permeability Channels	Yes

Despite having a density of 35° API, the crude has a paraffin concentration that varies from 10% to 25% (depending on the reservoir) and a paraffin crystallization temperature that ranges from 50 to 60° C. As a result, the entire manufacturing system is experiencing issues (Sparke et al. 2005).

The very first recovery enhancement practice applied to the field was cold water injection in 1967. The decision to do cold water injection was unsuccessful and resulted in a sharp decline in the productivity of the wells (Soroush et al., 2021). These wells were used to inject untreated water, seawater, and wastewater. As a result, dangerously high quantities of hydrogen sulfide and very radioactive scale deposits were created. Cold, untreated Caspian seawater injection caused the paraffin to crystallize and clog the formation's pore space, especially around the injection wells. The waterflooding's sweep efficiency decreased as a result. In addition, the high water cut of the wells was a result of the injected water bypassing oil in numerous locations as the cool water traveled via the most permeability/least resistance paths to the production wells.

After 2 years of cold water injection, as soon as the damaging consequences of this treatment were established, a rehabilitation program for cleaning paraffin and scale and hot water injection was initiated. The initial injection of hot water into Uzen Field was unsuccessful in terms of sweep efficiency, preventing paraffin accumulation or decrystallization. This was due in part to the injection process's slow implementation. According to the US CIA (1982), six years after launching a hot water injection program, the facility could only heat up 10 to 15% of the injected water. Knowing that higher temperatures are required to return paraffin to a solution, the paraffin precipitation had become so abundant due to poor field management that the rehabilitation program appeared ineffective. Because the oil's viscosity was already low (3 to 4 cp) at reservoir conditions, hot water injection had little effect on the oil's mobility. Only pore plugging caused by paraffin precipitation would be reduced by the process. However, subsequent research has shown that hot water flooding can increase the recovery factor by up to 40% (Bedrikovetsky, 1997).

Nowadays, hot water injection alone doesn't result in a high production rate in this field as high water cut is still a challenge for the local oil production wells. According to the production history of the field represented in Figure 9, the average water cut reached about 90% and a recovery factor of 34.6% by 2021 (Imanbayev et al, 2022a). Moreover, based on the depletion rates of the recoverable reserves shown in Figure 10, weak water flooding performance can be supported further.

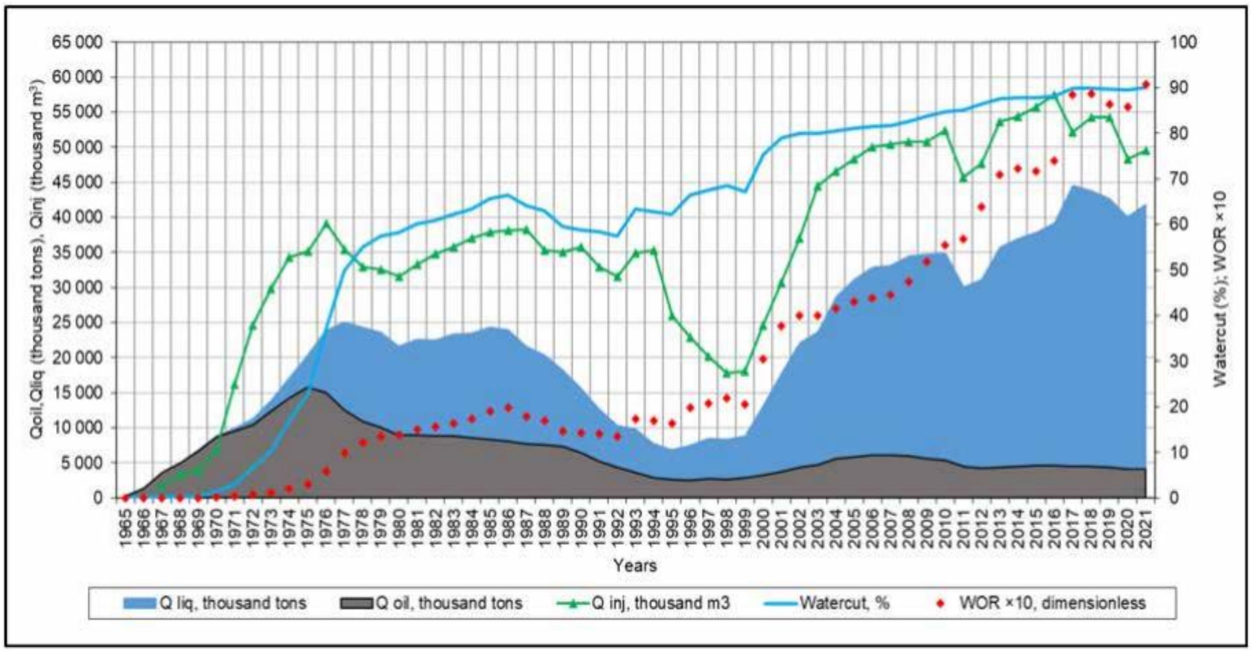

Figure 9. Production data of the Uzen field since 1965 (Imanbayev et al., 2022a)

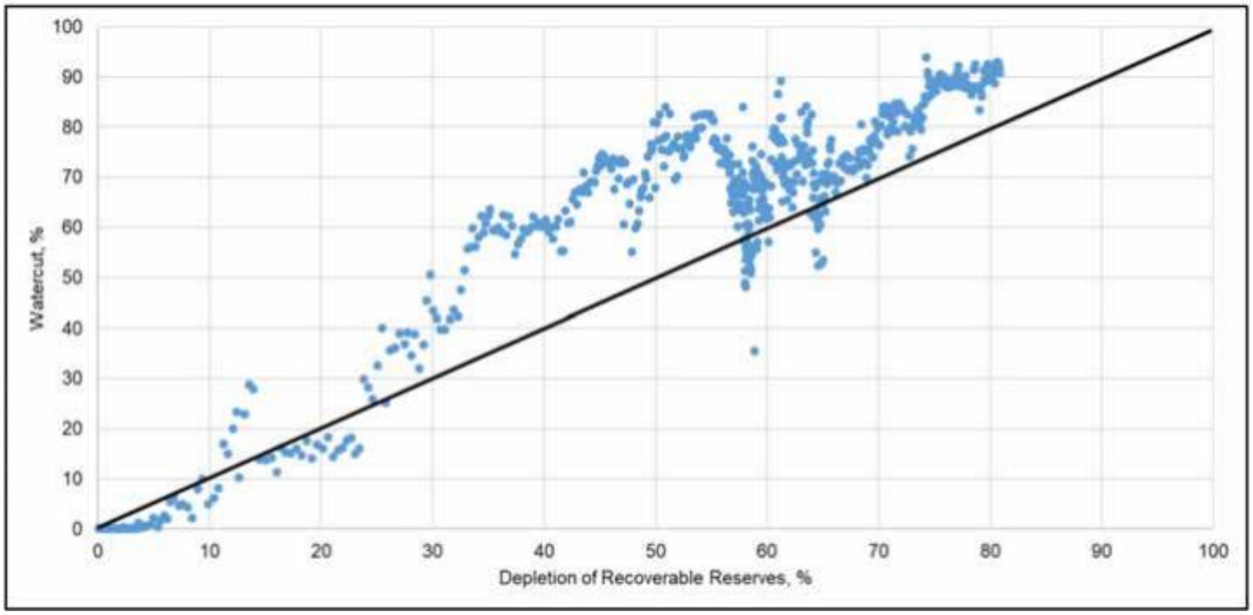

Figure 10. Water cut in the Uzen field as a function of depletion of recoverable reserves (Imanbayev et al., 2022a)

This trends reveal the necessity of the application of tertiary recovery methods with the objective of decreasing water production in the field. Considering this fact and in accordance with the screening criteria, all parameters except for the viscosity of the oil (3.5-4.2 cP is not in the range of 10-150 cP for polymer flooding) fit the screening criteria for polymer flooding shown in Table 1. Indeed, the criteria fitting of this chemical EOR technique is presented in Figure 11.

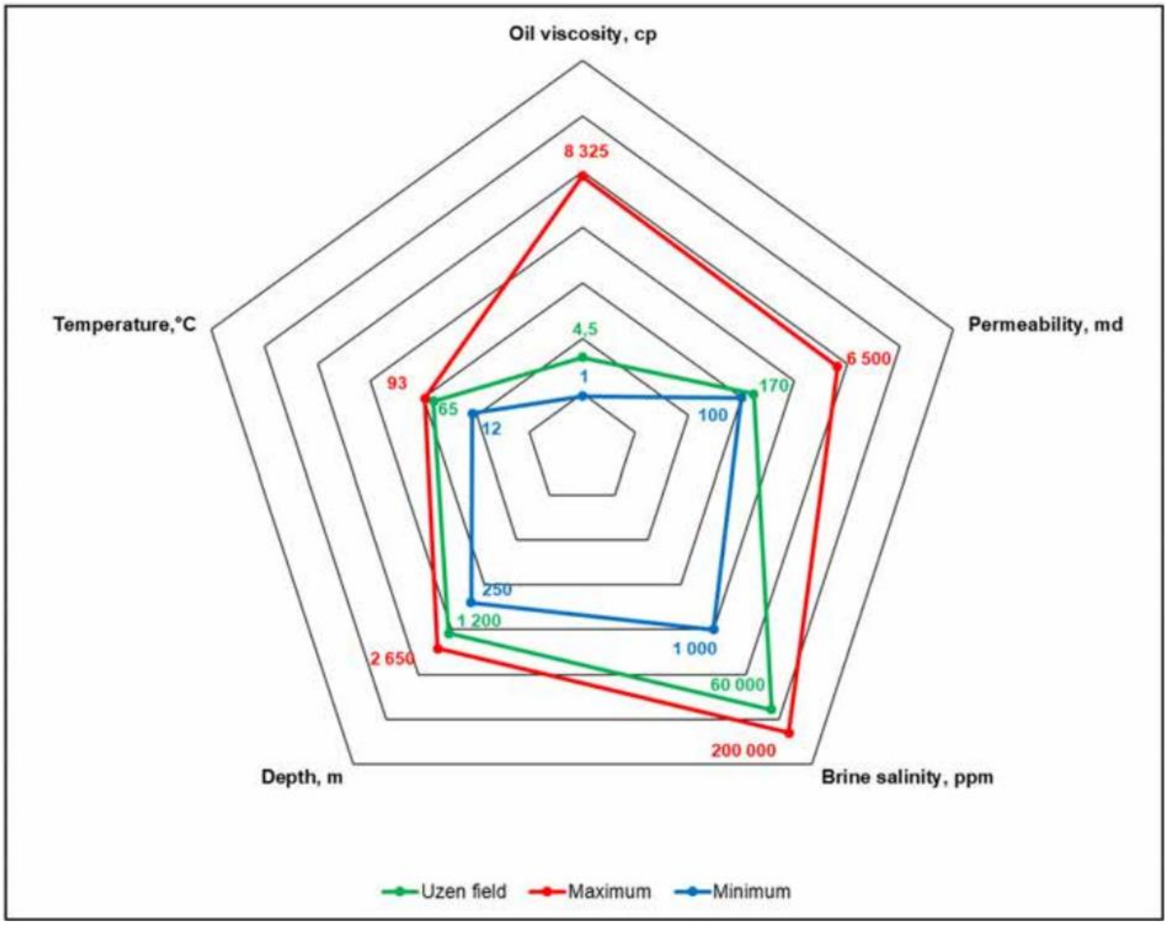

Figure 11. Polymer flooding applicability screening for the Uzen field (Imanbayev et al., 2022a)

The pilot testing of polymer flooding has been successfully performed for more than 10 years through 3 injection and 14 producer wells of the field by KazMunaiGas Engineering service company (Imanbayev et al., 2022a). As a result, having 4.7% of cumulative oil recovery from the pilot testing, it was proven that polymer flooding is an effective technique to control the mobility of the water, decrease water cut, and increase oil production. Besides, the company discovered an opportunity to use 19,000 cubic meters of Alb water per day for waterflooding, which is derived from the Albian layer of local stratigraphic column. In further research by Imanbayev et al. (2022b), the effectiveness and compatibility of both Caspian seawater and Alb water was observed and proven to be used as a solvent for future polymer flooding tests on the field. Nevertheless, to have a clear view of how polymer flooding may affect Uzen field performance, the application of the polymer flooding in several analogous fields should be analyzed and the comparison in the rock and fluid properties with the Uzen field should be done.

2.1.3. Polymer Flooding in Analogous Field to the Uzen Field

Successful implementation of polymer injection was applied in Aishwariya Field, Rajasthan, India. The oil produced in the Aishwariya field has a viscosity of 10-30 cP (Singh et al., 2021). The field is considered to be analogous to the Uzen field in terms of the wax content on oil and the similar temperature of the reservoir. By looking through the screening criteria it was identified that polymer chemical EOR would be suitable for Aishwariya Field's reservoir characteristics. After the lab work studies and simulation work, it was decided that the polymer flooding should be conducted in 2 stages. In the first stage, the performance of the polymer flooding was tested in the field by converting 2 of the producing wells into polymer injectors. As a result, a significant reduction in water cut from 57% to 29% and an increase in oil rate from 1700 BPD to 2100 BPD was observed at 2 producing wells near the injectors. Also pressure support, viscosity increase around the wellbores, and WOR stabilization were observed in nearby wells. However, injectors had good conformance only at the beginning and it deteriorated over time. This information together with a collection of different samples of polymers from the wellhead, injection water, etc, was useful for implementing the second stage. In the second stage, full-field polymer injection at Lower Fatehgarh (LF) formation was designed and implemented. As shown in Figure 12, the oil rate increased from 7000 BPD to 10700 BPD, and the water cut decreased from 84% to 81%. Significant water cut decrease was observed in some wells achieving up to 45% WC reduction (refer to Figure 13). As a result, the actual performance of the sector is better than expected.

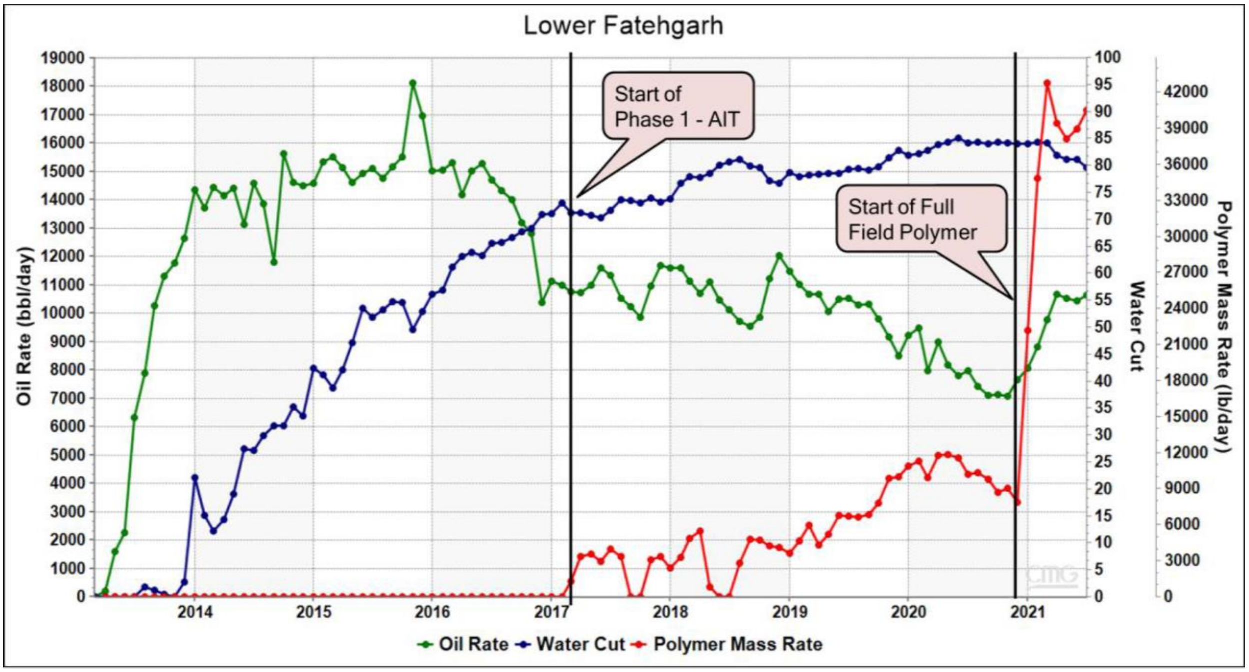

Figure 12. Full field polymer flooding at Lower Fatehgarh (Singh et al., 2021)

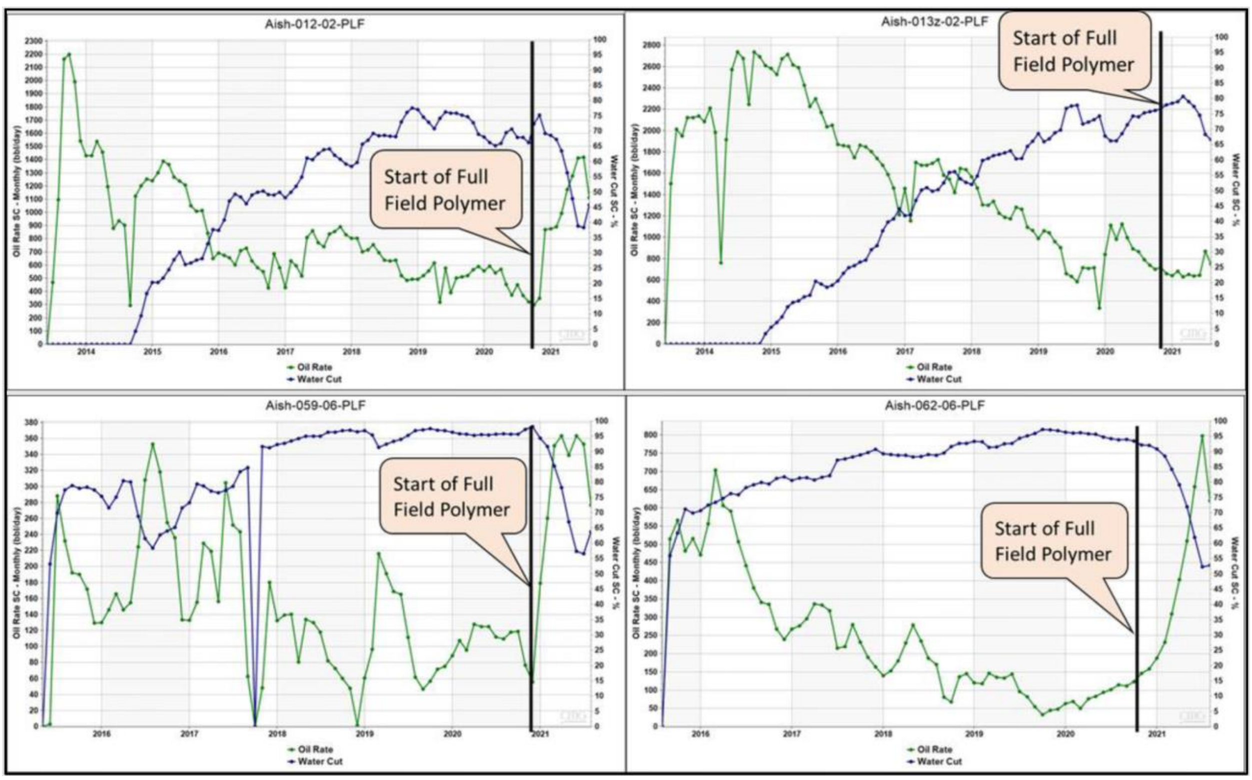

Figure 13. Well performance in Lower Fatehgarh (Singh et al., 2021)

Polymer flooding was successfully used at Daqing Field, China. Daqing Field is very similar to the Uzen field in terms of lithology - sandstone, density ranging from 33 to 39° API, depth of 900-1200 meters, the permeability of 500-1000 mD, porosity ranging from 25 to 30 % and high wax content. The only parameter that is very different is the viscosity of the oil (35 cP). The polymer injection in this field even at the pilot stage showed 12% incremental oil recovery. In 2019, "the total incremental oil production … polymer flooding alone represented 6.03 million tons." Figure 14 represents the polymer flooding oil production in this field and it can clearly be stated that the polymer injection was successful in the field (Ezeh et al., 2021).

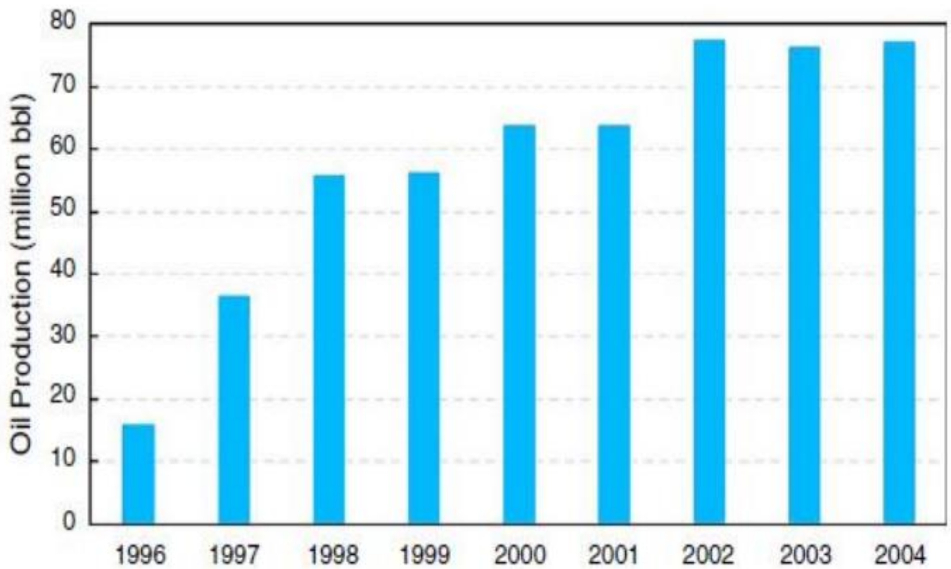

Figure 14. Polymer flooding oil production in the Daqing field (Ezeh et al., 2021)

Polymer flooding at the Bhagyam Field, Rajasthan, India was also successfully implemented. The Bhagyam field has similar properties to the Uzen field. The oil produced in the Bhagyam field has a viscosity of 15-20 cP (Agrawal et al., 2015). The lithology is sandstone, permeability ranges between 1 to 10 Darcy, and porosity range is 25-30%, As a result of polymer injection, 1% to 35% of water cut drop across all of the producers in the field, and an increase in oil production rate from 10500 BPD to 15500 BPD have been observed (Koduru et al., 2021). Figure 15 shows how the polymer injection dropped the produced WOR from 16 to 10. Figure 16 shows the changes in the oil production rate and water-oil ratio after the polymer flooding.

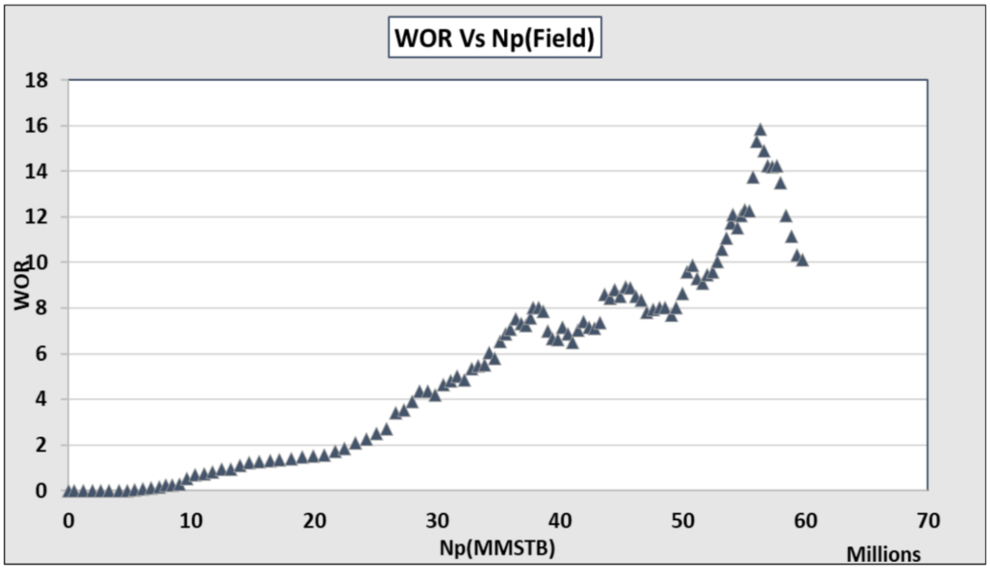

Figure 15. WOR over Np in Bhagyam field (Koduru et al., 2021)

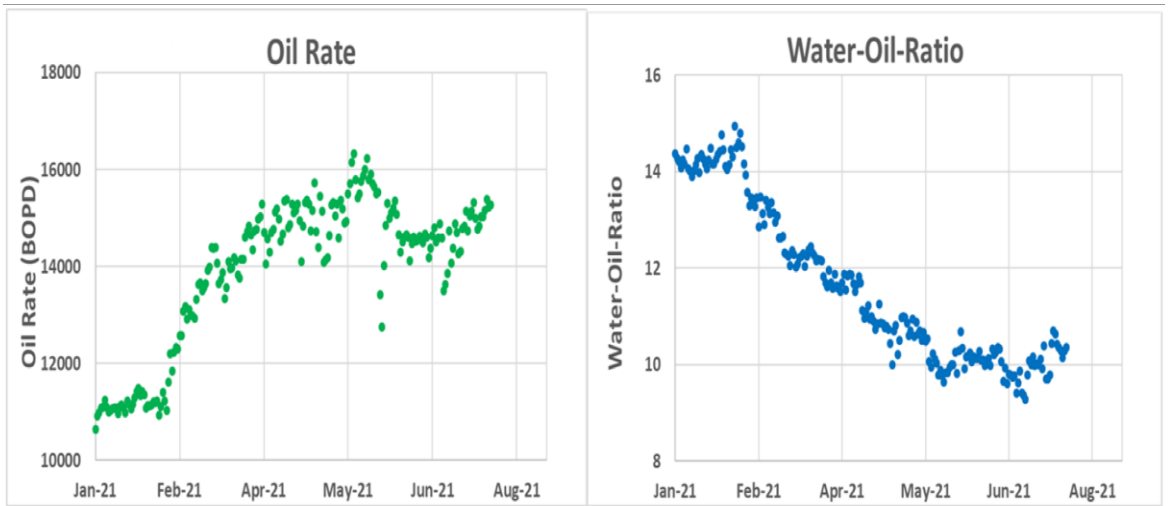

Figure 16. Field oil rate and WOR trend post polymer expansion (Koduru et al., 2021)

Polymer injection was successfully implemented at the Al Khalata reservoir in the Sultanate of Oman field. The field's lithology is sandstone, density is 22º API, and viscosity is 90 cP. The reservoir has a permeability of 100 mD to 2 Darcy and porosity ranges between 25 to 30%. As a result of the polymer flooding in the reservoir, the water cut drop is between 2-30% and the increase in oil production is about 25% (Singh et al., 2021). Figure 17 shows the oil gain and water cut reduction after the polymer injection application.

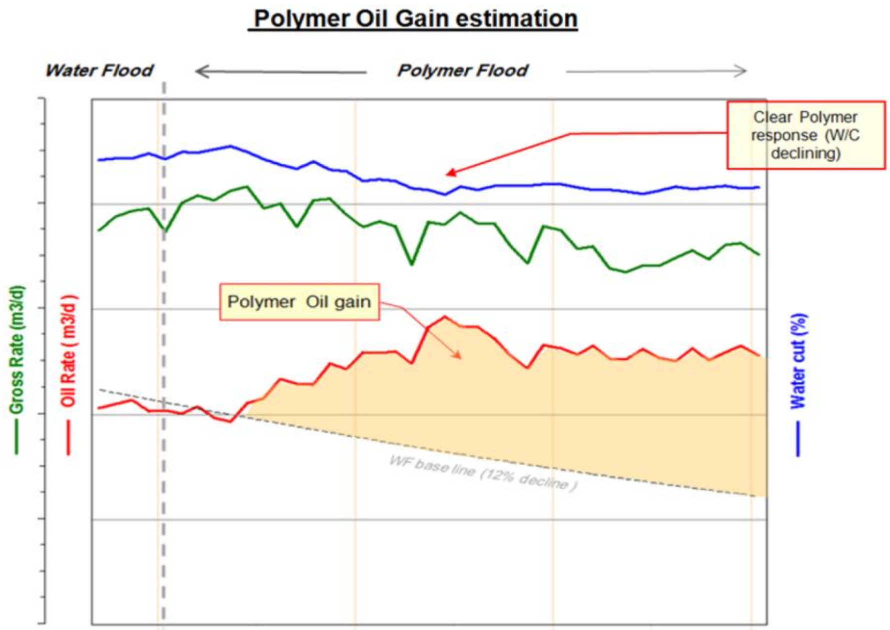

Figure 17. Oil gain and water Cut after the polymer flooding (Singh et al., 2021)

The success of polymer flooding in similar fields to the Uzen field all over the world shows that the implementation of the polymer EOR method should result in similar behavior, and increase in the oil production and decrease in the water cut.

2.1.4. Polymer Screening: Previous Studies on Polymer Performance

The success behind the design of the efficient polymer flooding project is based on the proper polymer type selection. Following the previous polymer screening studies made in the discussed analogous fields, the following screening tests are implemented to evaluate the suitability and stability of the selected polymer: rheology test, thermal stability, static adsorption, dynamic adsorption, and oil displacement evaluation for the Uzen field.

In the previous research made by Yerniyazov and Yesmukhambet (2022), a series of screening tests were performed in the laboratory to examine 4 polymer candidates provided to be injected in the Uzen field. Two important field parameters were the base throughout the conducted experiments: the salinity of the polymer solution to be injected equal to about 14000 ppm and reservoir temperature of 63°C. The main objective of the conducted set of experiments was to select the most suitable and efficient polymer type, which can significantly reduce the mobility of less than one, with acceptable rheological, thermal stability, and adsorption results for the Uzen field. The target was to reach the viscosity of 5 cp at a shear rate of 10 [1/s] in the reservoir conditions.

The aim of the rheology test, in particular, was to evaluate the shear thinning behavior of the fluid and to establish the correlation between polymer concentration and its viscosity values. The viscosity results are presented in Figure 18 and reveal that a significantly higher concentration of polymer is needed for Polymer 1 to reach the target viscosity of 5 cp in comparison with the other three candidates. Thus, the application of Polymer 1 is not economically beneficial, as a higher concentration of polymer leads to a higher cost for the EOR project.

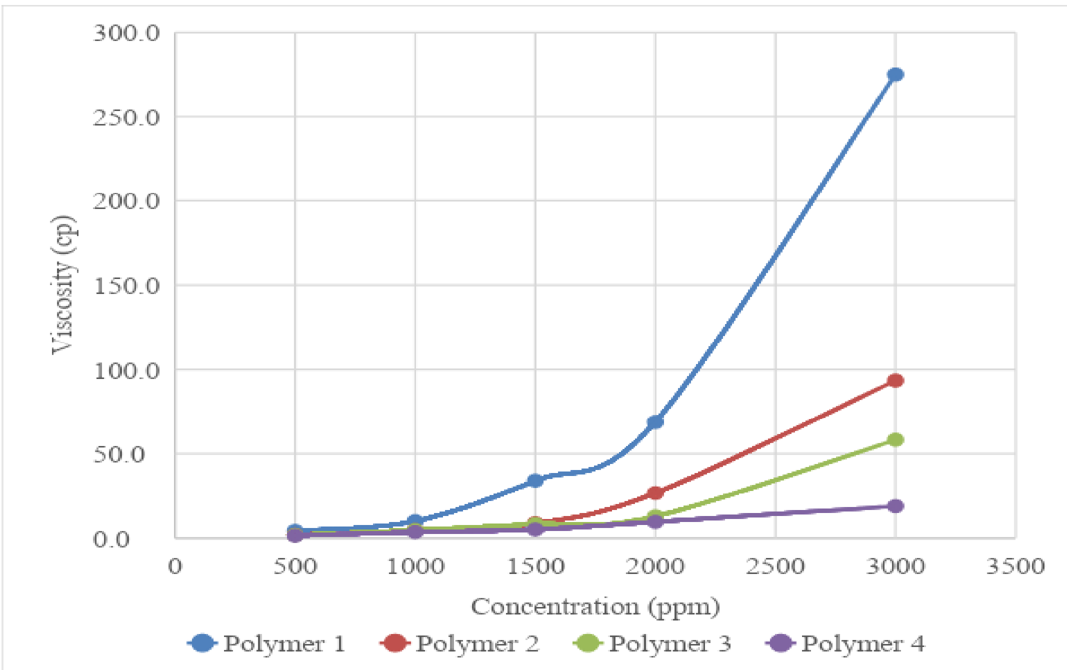

Figure 18. Rheology results (Yerniyazov & Yesmukhambet, 2022)

The thermal stability test aimed to estimate the thermal degradation of the polymer caused by the high reservoir temperature. In Figure 19 high viscosity degradation can be observed in the first 10 days of the experiment at a temperature of 63°C, then, viscosity stabilization is reached.

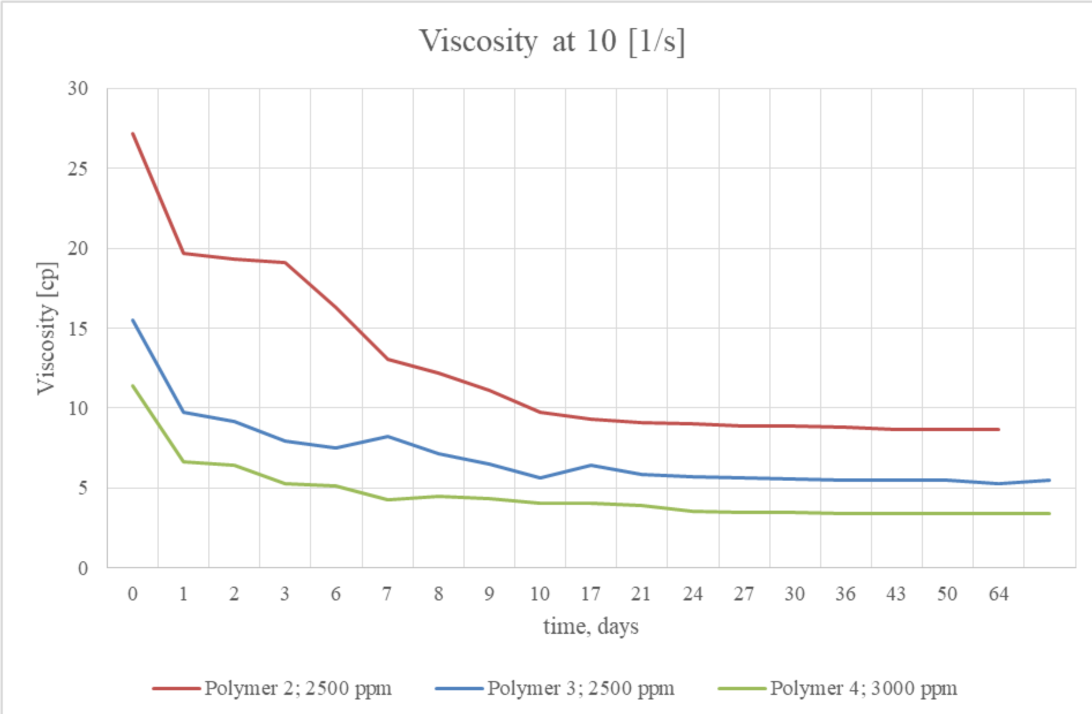

Figure 19. Thermal stability results (Yerniyazov & Yesmukhambet, 2022)

Based on the obtained results, the correlation between initial viscosity, viscosity degradation, and concentration was used to determine the stabilized (final) viscosity of polymers as a function of polymer concentration as shown in Figure 20. From this graph, it can be observed that Polymer 4 is not able to reach stabilized viscosity at 5 cp at any given concentration, meanwhile, Polymer 2 and Polymer 3 can reach the target viscosity after stabilization.

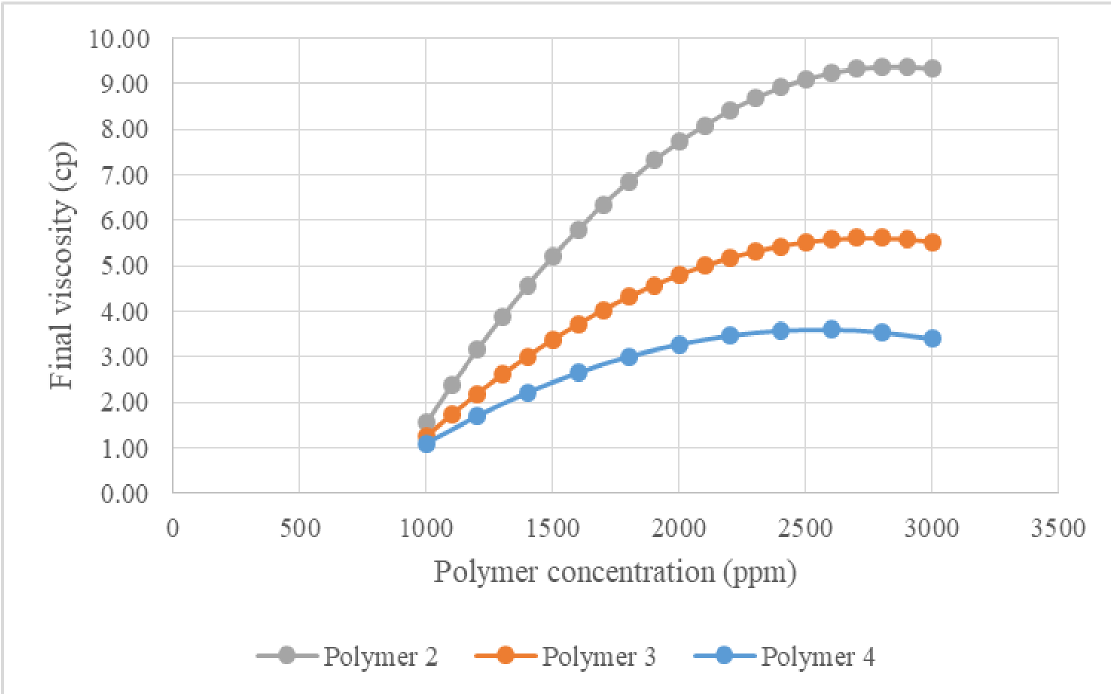

Figure 20. Stabilized viscosity results as a function of polymer concentration (Yerniyazov & Yesmukhambet, 2022)

Further, the adsorption test was conducted with the use of a polymer solution prepared with real Caspian sea water and mixed with the crushed Upper Berea sandstone core sample. The results of polymer solution adsorption and retention in porous media collectively lead to a decrease in the displacement phase's permeability (Zhu et al., 2021). The two primary approaches for investigating polymer solution adsorption are dynamic and stationary adsorption. Despite the fact that some static adsorption techniques have a low connection to the real adsorption state, they are simpler to do and comprehend. For consistency and precision of the results, 3 polymer concentrations (1000 ppm, 1500 ppm and 2500 ppm) and 7 solid-to-liquid ratios (1/2, 1/4, 1/6, 1/8, 1/10, 1/50, and 1/100) were tested. From Figure 21 and 22, it can be concluded that Polymer 2 has higher adsorption at any given solid-to-liquid ratio and regardless of the polymer concentration.

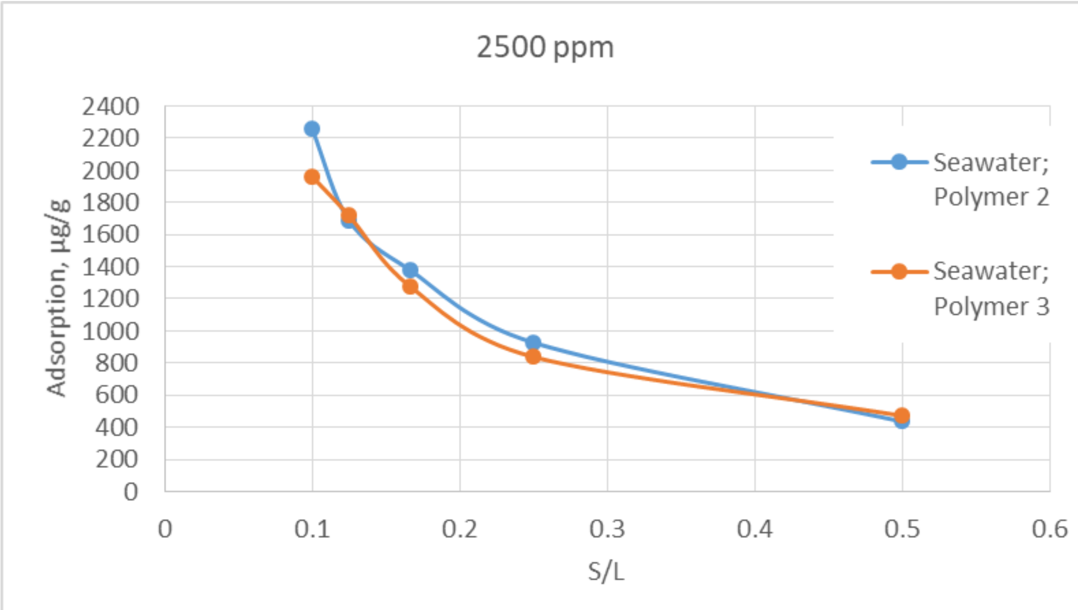

Figure 21. Adsorption results as a function of solid-to-liquid ratio (Yerniyazov & Yesmukhambet, 2022)

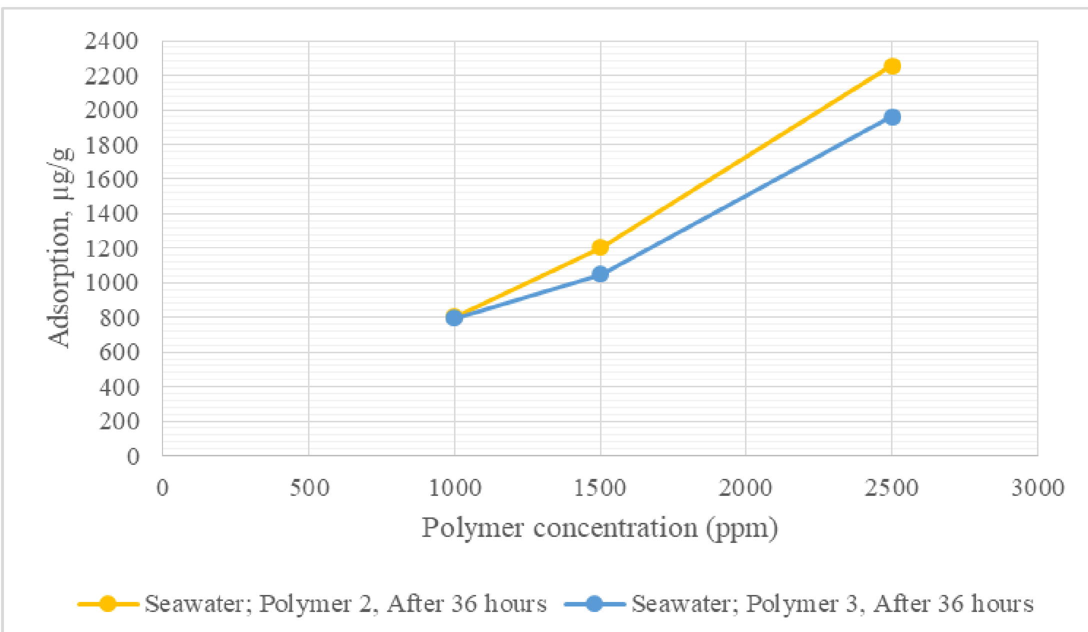

Figure 22. Adsorption results as a function of polymer concentration (Yerniyazov & Yesmukhambet, 2022)

To sum up, the results of these screening experiments revealed that the most suitable for the Uzen field polymer type with the lowest adsorption and thermal degradation values is Polymer 3, while its optimal and economically beneficial concentration is 2500 ppm. That is why Polymer 3 of 2500 ppm is selected for further performance evaluations in the porous media.

2.1.5. Problem Statement

The main point behind the application of any EOR technique is increasing the recovery factor of the oil, and polymer flooding is not an exception. The core samples are necessary to be flooded by polymer and the recorded data during the flooding should be analyzed to determine the polymer degradation, injectivity, and recovery factor of the conducted flooding. These three parameters are significant for the proper evaluation of the polymer behavior and performance in the porous media. The proper analysis of the final result will show the incremental recovery of the oil and whether it is efficient to use the selected polymer further on the full-field scale or not.

To improve the application method and guarantee application efficiency, it might be important to understand the adsorption process and its affecting elements. Dynamic adsorption is determined based on the sum of adsorption and retention, not just one adsorption variable (Zhu et al., 2022). The hydrophobically associating polymer AP-P4 and partly hydrolyzed polyacrylamide (HPAM) are now the most frequently utilized polymer solutions for oil displacement in oilfields (Diaz et al., 2020). But for the former one, the effect of the adsorption mechanism is especially prominent. It occurs by chemisorbing on the medium's surface by electrostatic and hydrogen bonding interactions, creating a stable monolayer characteristic (Zhu et al., 2022). According to the studies (Zhu et al., 2022), the following factors can hugely affect the adsorption rates of the polymer during injection into the porous media: (1) the effect of the fluid's movement on the external force that affects its adsorption, (2) the effect of the fluid's effective contact time with the medium surface in the flow process, (3) the effect of the fluid's effective adsorption area between the medium, and (4) the effect of the concentration change brought on by the fluid's adsorption, or the effective adsorption concentration. Consequently, by evaluating the adsorption rates of the polymer injected into the core, we can consider all these factors to understand the polymer treatment performance.

During the core flooding tests, the polymer is injected into the core sample under the reservoir pressure and temperature, which are high enough to cause the degradation of the polymer molecules. The polymer molecules are very sensitive to any deviations, whether it is temperature or pressure rise, mechanical rotation, compression, or expansion, the polymer can degrade to any of these factors. A combination of all the degradation factors will show how the polymer is going to behave as it was injected down into the reservoir. The polymer degradation is calculated as follows:

$$Polymer\ Degradation = \frac{\mu_p - \mu_{effluent}}{\mu_p} \times 100 \qquad (2)$$

, where

μ_p is the initial viscosity of the polymer;

$\mu_{effluent}$ is the viscosity of the effluent;

The recovery factor is the most important factor to be known when it comes to EOR application. The recovery factor shows how much of the increment in oil production can be obtained after the polymer treatment. The recovery factor calculation formula is as follows:

$$Recovery\ Factor = \frac{V_{oi} - V_o}{V_{oi}} \times 100 \qquad (3)$$

, where

V_{oi} is the original oil in place (OOIP);

V_o is the volume of oil produced after the flooding;

On average, polymer flooding is by 6-12% higher than waterflooding and can result in oil recovery of 40-50% (Speight, 2019). Main objective at this stage is to evaluate the recovery limits that can be achieved by the injection of the selected polymer at the selected concentration considering all the screening criteria and degradation factors, which were discussed above. Therefore, proper screening of polymers can significantly raise the field’s profitability.

Chapter 3

3.1. Methodology

In this section a stepwise methodology of the experiment will be provided to achieve the objectives of the research. To start with, all the materials that were used in the experiment should be properly prepared in advance. The preparation process should follow the procedures indicated in the previous similar studies discussed above. At the same time, the materials should be prepared in a way that will simulate the Uzen field reservoir conditions that were provided above. The core samples, crude oil, and brine were provided directly from the field by the KazMunaiGas Engineering company for research purposes. After the proper sample preparation process, the core flooding system can be set following the experimental manual and HSE regulations. Finally, the core flooding tests initiated and continued without any interruptions till the end of the test, recording all the obtained pressure, permeability, and volume data, which will be used for further calculations and data interpretation. All these stages of the experiment will be further discussed in detail.

3.1.1. Materials

3.1.1.1. Crude Oil

Crude oil for core saturation is also provided directly from the Uzen field (Figure 23). The oil has a viscosity of 8 cp at 63℃ temperature and atmospheric pressure of 14.7 psi. Additionally, density and viscosity vs shear rate graphs were provided in Figure 24.

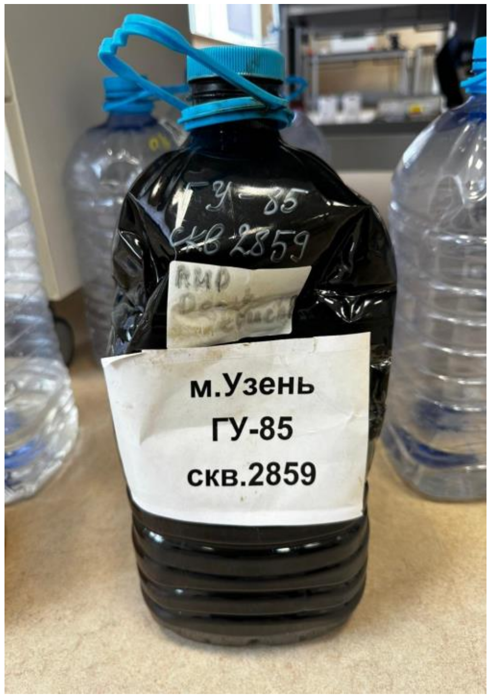

Figure 23. Uzen field crude oil

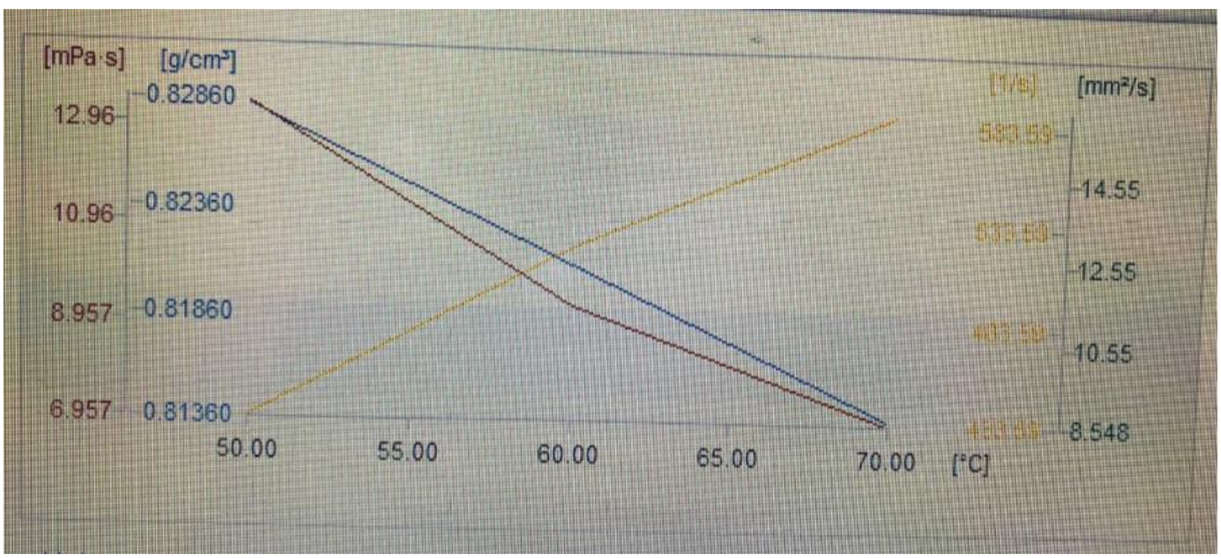

Figure 24. Viscosity and density vs. shear rate graph for the Uzen field

3.1.1.2. Brine

First, the core samples will be saturated with the provided formation water (FW) sample derived from the Uzen field (Figure 25), in order to best fit the reservoir condition, considering the specific contamination of the local water. According to the information provided by the provider company, the density of the formation water is 1.1 g/cc. Then two tests will be performed using two types of brine: first, using Caspian seawater (SW) and second, Alb water, to be injected into the core as a preflush stage and used as a base for the polymer solution. Caspian seawater has a salinity of about 13,000 ppm and is supposed to have some bacteria in it. Therefore the brine is kept in the refrigerator to maintain its initial properties as long as possible (Figure 26).

Figure 25. Formation water sample

Figure 26. Brine samples in refrigerator

The exact composition of both types of brine was estimated beforehand by inductively coupled plasma-optical emission spectroscopy (ICP-OES) and provided in Table 3**.** The composition of DI water is also provided for equipment reference purposes.

Table 3. Composition of the Uzen Field's formation water and Caspian seawater

Ions	DI water (ppm)	Formation water (ppm)	Caspian seawater (ppm)	Alb-water (ppm)
Ag	0.03	0.09	0.1	0.16
Al	0.35	0.94	0.2	0.33
B	34.45	21.65	15.41	26.72
Ba	0	9.85	0	0

Be	0.01	0.01	0.01	0
Ca	0.84	3359	363.3	179.9
Cd	0.12	0	0.02	0.06
Co	0	0.52	0.34	0.15
Cu	0.03	0.13	0.11	0.06
Fe	0.11	0.09	0.14	0.1
Ga	0	0.1	0.27	0
Hg	0.06	0.05	0.06	0.06
K	2.57	269.8	89.61	28.95
Li	0	2.29	0.19	0.2
Mg	0.61	1127	809	84.06
Mn	0.04	2.28	0.03	0.05
Mo	0.16	1.51	0.75	0
Na	0.13	15180	2920	3032
Ni	1.93	1.41	1.87	1.22
P	0.33	0.37	0.38	0.35
Re	0.51	0.5	0.5	0.5
Sb	0	0	1.05	0
Se	5.98	25.07	8.83	38.68
Si	30.74	18.49	15.13	21.47
Sn	0.55	0.57	0.56	0.55
Sr	0	159.6	8.89	6.03
Ta	0.05	0	0.14	0.13
Ti	0.01	0.4	0.03	0.07
V	0.52	0.3	0.37	0.22
Zn	0.34	0.48	0.69	0
Zr	0	0.06	0.06	0.05

Before the usage for the experiment, both types of brine were filtered by a manual filter tool (Figure 27) using a filter paper with a pore size of 30 µm (Figure 28), in order to get rid of any waste and solid particles. That is done to prevent blockage of the pores in the core sample by alien particles, which can cause inaccuracy in the results.

Figure 27. Manual filter

Figure 28. Filter paper

3.1.1.3. Core Sample

For this research both oil displacement tests were performed on a sandstone core samples taken from the Uzen field. The length and diameter of the core were measured in advance using a Vernier caliper (Figure 29). To calculate the pore volumes of the specimens the cores were saturated with formation water using a manual saturator (Figure 30). For that purpose, the core is firstly depressurized by a motor pump to make a vacuum, and then saturated with the formation water under constant pressure at 1000 psi controlled by a manual pump, and left for 12 hours.

Figure 29. Manual Vernier calliper

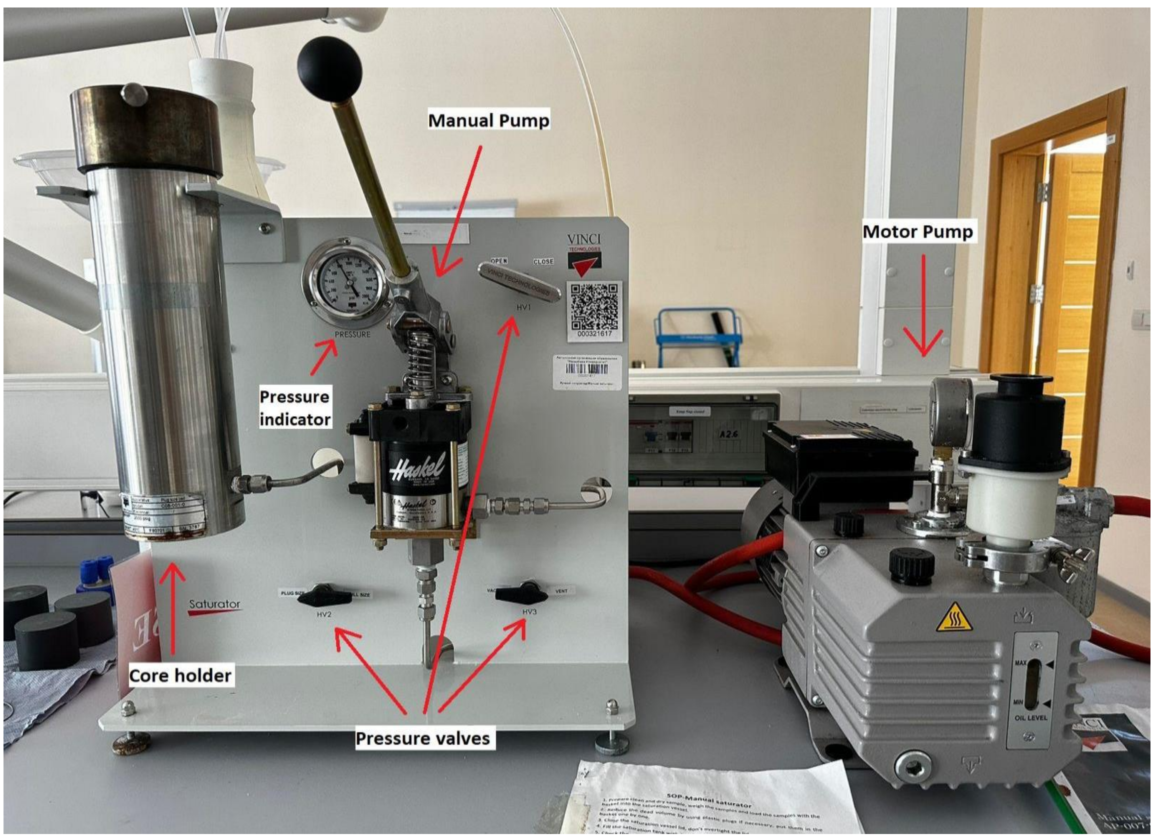

Figure 30. Manual core saturator

Dry weight (W_{dry}) of the core before the saturation and wet weight W_{dry} after the saturation are putted into the following equation to calculate the PV of each core sample:

$$PV = \frac{W_{wet} - W_{dry}}{\rho_{FW}} \tag{4}$$

The main properties of the core sample are provided in Table 4.

Table 4. Uzen field core sample properties

Experiment	**Density (g/cm^3)**	**Dry weight (g)**	**Wet weight (g)**	**Length (cm)**	**Diameter (cm)**	**PV (cc)**	**Porosity (%)**
Caspian seawater case	2.652	120.15	136.91	5.55	3.786	15.2	24.3
Alb water case	2.641	124.47	141.28	5.7	3.78	15.3	23.9

3.1.1.4. Polymer

As it was revealed from the polymer screening part, Polymer 3 with a concentration of 2500 ppm is selected for oil displacement studies. The polymer solution is prepared in accordance with API63 standards, and there are specific steps suggested for preparing the solution in a laboratory setting using dry polyacrylamide products. Polymer 3 provided by the company is in powder form (Figure 31). Typically, a stock solution of around 5000 ppm polyacrylamide is prepared and then diluted to the needed concentration. To disperse the dry powder effectively, strong stirring is necessary and the bottom of the water vortex on a laboratory stirrer driven by a magnet should penetrate 75% into the liquid (Figure 32). Within 30 seconds, the dry polymer is continuously added to the vortex shoulder. Immediately after that, the stirrer should be set at a low speed (150 RPM) to prevent solid particles from sinking and also to avoid degradation of the polymer solution. The solution is mixed gently for 2-3 hours before letting it sit overnight. To reduce evaporation and potential errors in results, the samples were covered with parafilm. The prepared polymer solution can be used in further experimental procedures after 24 hours (API Recommended Practice 63, 1990).

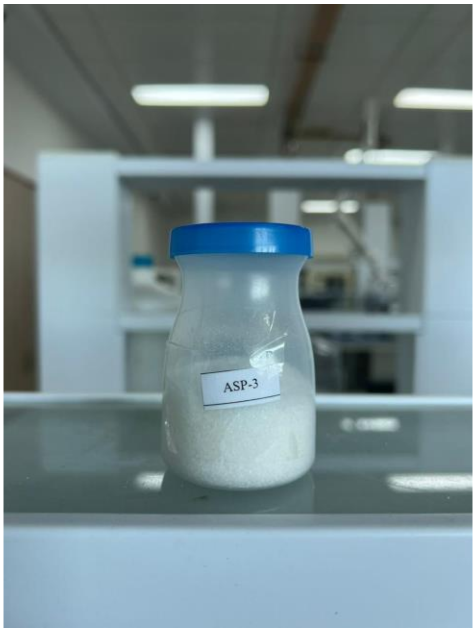

Figure 31. Polymer 3 powder

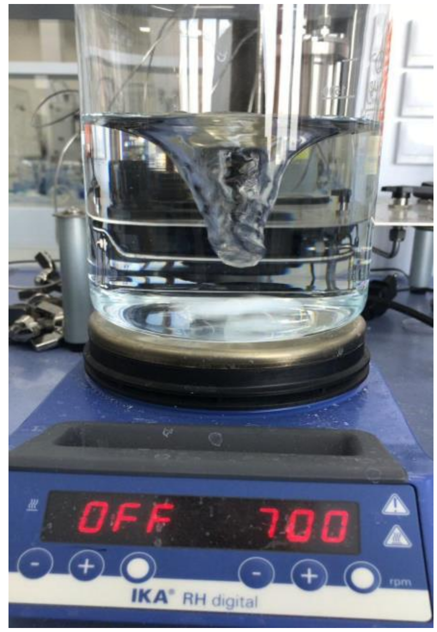

Figure 32 . Polymer solution preparation

3.1.2. Procedure

CFS-700 Core Flooding System for EOR (Figure 33) was used to conduct the oil displacement by polymer injection. Through the use of the CFS-700 apparatus core sample was tested for oil displacement by polymer flooding under the reservoir conditions (Figure 34). The workflow of the apparatus is controlled by the unique software provided by Vinci Technologies. The operation of the valves, the pumps (Figure 35), the fluid flow, pressure differences (ΔP), and the volume of the fluids inside the accumulators were all controlled and monitored through the computer (Figure 36).

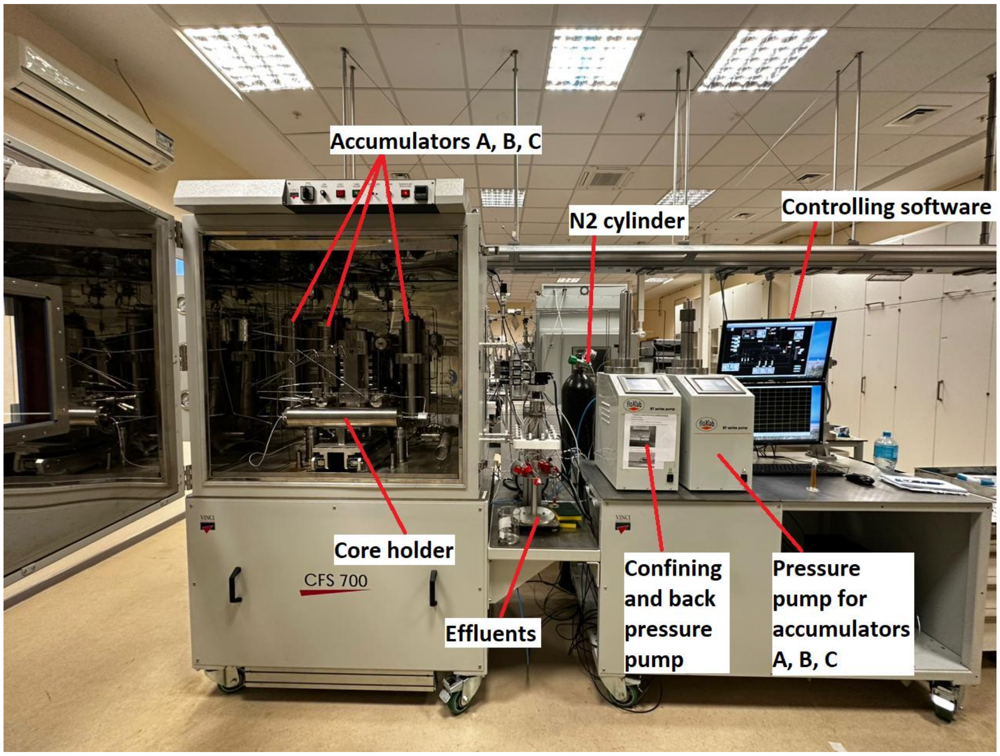

Figure 33. CFS-700 Core Flooding System for EOR

Figure 34. The inside of the CFS-700 apparatus

Figure 35. Pressure pumps of the CFS-700 apparatus

Figure 36. The control of CFS-700 workflow through the software

For rheology measurements of polymer and the effluents, the Anton Paar rheometer was used (Figure 37). This equipment is intended for the measurement of non-Newtonian fluids, giving the viscosities for the set range of shear rates. For comparability of the results, the viscosity values at a shear rate of 10 1/s were used.

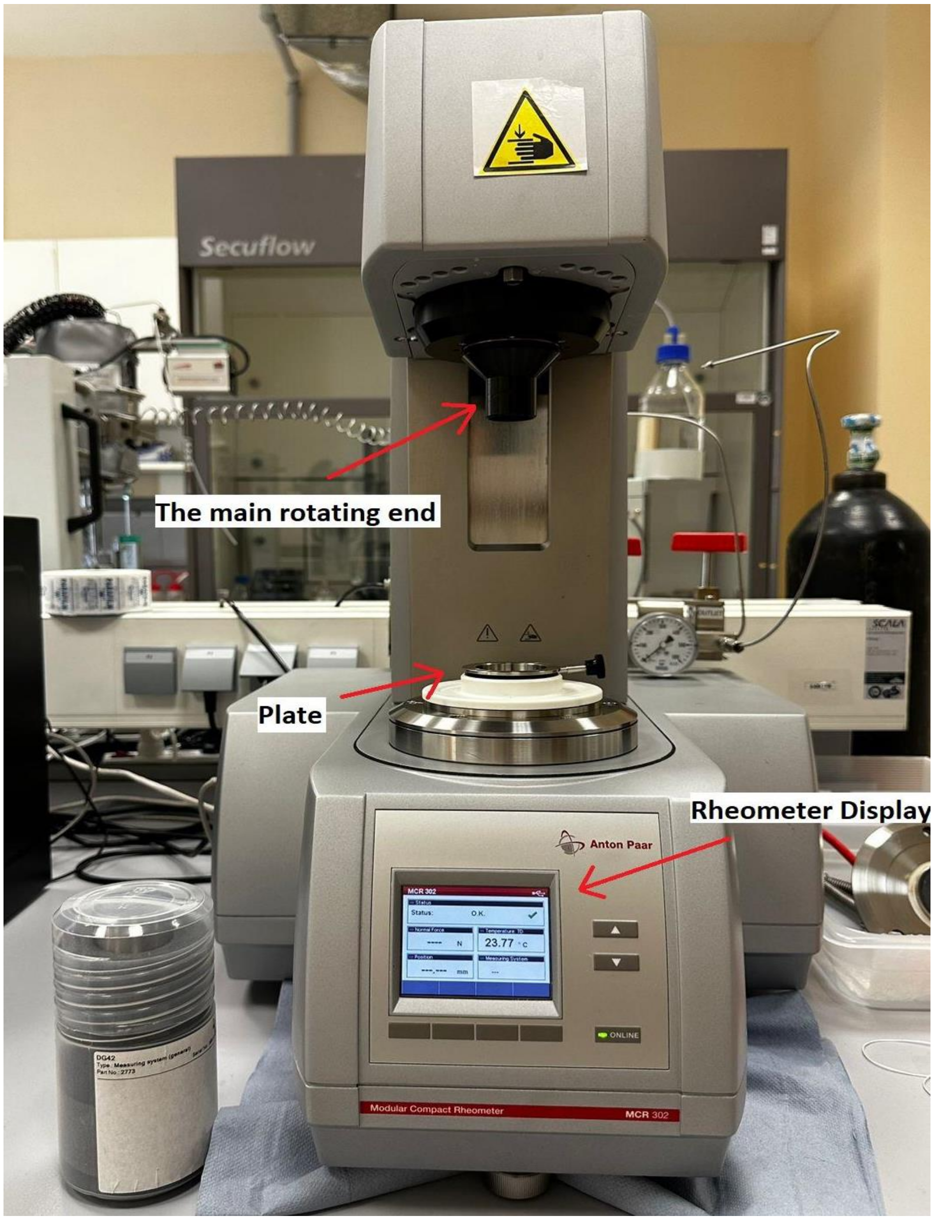

Figure 37. Anton Paar rheometer

The procedure steps of the oil displacement by the polymer flooding are listed below:

- The core sample was saturated with FW and then flooded with FW at different rates to determine the absolute permeability of the core. The saturated core will be aged for a week to achieve the initial water-wet state;
- The CFS system is set in accordance with the reservoir conditions with a temperature of 63°C and confining pressure of 1500 psi. For safety reasons, the back pressure was set at 300 psi. Accumulators A, B, and C are filled with suitable fluids (SW, oil, polymer solution);
- In the next step, the crude oil was injected into the core at a flow rate of 0.2 cc/min and was continued until the effluent water cut was reduced to less than 0.1%. The injection rate was raised up to 0.5, 1.0, 1.5, and 2.0 cc/min to overcome capillary end effects and to reach initial water saturation (S_{wi}) in the core. The conditions for switching the flow rate were to have an effluent water cut of less than 0.1% and a stabilized pressure drop across the core sample;
- The water production data was used to calculate S_{wi} in the core using the following equation:

$$S_{wi} = \frac{PV - V_w}{PV} \times 100\% \qquad (5)$$

  , where V_w is water volume produced after oil injection, and PV is for 1 pore volume of the specimen;
- Then the core was flooded with the brine to obtain oil recovery by waterflooding. At each step, brines were injected at a rate of 0.2 cc/min until the oil cut in the effluent was less than 0.1% and a stable pressure drop was maintained. The water injection rate was then increased to minimize capillary end effects and to reach residual oil saturation after waterflooding (S_{orw});
- The volume of oil produced during waterflooding was used to calculate the recovery factor using Equation 3;
- In the next step, polymer solution at 2500 ppm concentration was prepared in brine and injected at 0.2 cc/min. The same criteria were observed to increase the flow rate to the next value. The volume of oil produced during this stage was used to calculate incremental

recovery by polymer flooding. 2500 ppm concentration was selected based on the tests done at the earlier stages of the research;

- The stabilized pressure drops for water flooding and polymer flooding were also used to calculate the two-phase resistance factor (RF) for comparison purposes;
- Equation 1 was used to calculate the mobility ratio (M) using fluid viscosities and permeabilities calculated for each injection stage using Darcy's law;
- Finally, a post-flush of the brine was performed to calculate the residual resistance factor (RRF) in presence of oil and to displace the adsorbed polymer.

Chapter 4

4.1. Results and Discussion

Oil displacement test was performed for two cases: first, Caspian seawater-based polymer injection after water flooding with Caspian seawater; second, Alb water-based polymer injection after water flooding by injection of Alb water.

4.1.1. Oil Displacement test with Caspian Seawater

Based on the pressure drop data obtained with each pore volume of injected seawater as a preflush, then seawater-based polymer and again seawater as a post-flush, a set of pressure drop data was obtained and plotted versus injected fluid pore volumes in the following graph (Figure 38). Referring to Table 4, one pore volume (PV) of the tested core specimen was calculated using Equation (4):

$$1\ PV = \frac{136.91\ g - 120.15\ g}{1.1\ g/cc} = 15.2\ cc$$

The obtained PV value was substituted into Equation (5) to estimate initial water saturation. The measured water volume produced after oil injection (V_w) is 12.16 cc.

$$S_{wi} = \frac{15.2\ cc - 12{,}16\ cc}{15.2\ cc} \times 100\% = 0.2 = 20\%$$

The measured dimensions of the core sample were 5.55 cm long and 3.786 cm in diameter. The porosity of the core sample is given by the ratio of its pore volume (PV) to bulk volume, V_b:

$$V_b = 5.55\ cm \times \left(\frac{3.786\ cm}{2}\right)^2 \times \pi = 62.5\ cc$$

$$\phi = \frac{15.2\ cc}{62.5\ cc} = 0.243 = 24.3\%$$

Given all these calculated data, the OOIP can be easily estimated as follows:

$$V_{oi} = V_b \times \phi \times (1 - S_{wi}) \qquad (6)$$

$$V_{oi} = 62.5\ cc \times 0.243 \times (1 - 0.2) = 12.15\ cc$$

Finally, the recovery factor was estimated using Equation (3) and also plotted versus injected fluid PV on the same graph (Figure 38). The V_o value in this equation was obtained from the oil volumes produced with each PV of injection (see Appendix B).

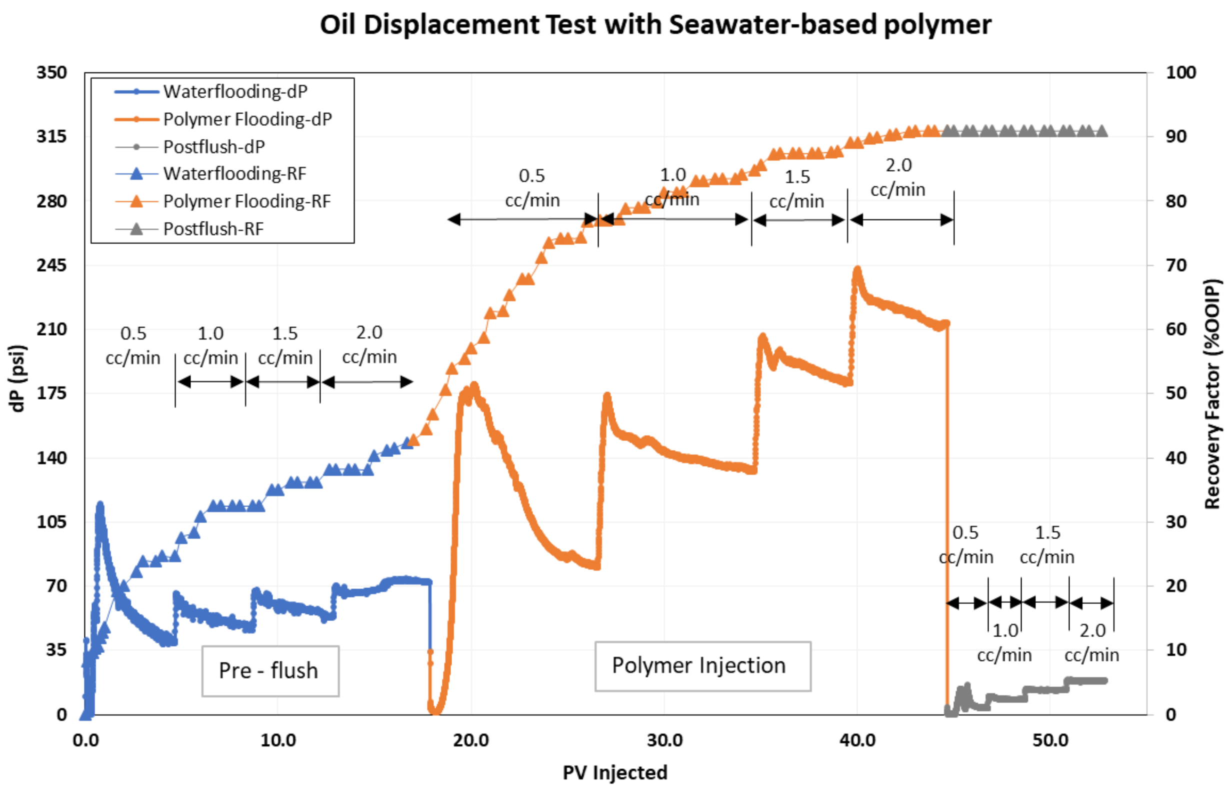

Figure 38. Oil displacement test with seawater-based polymer

The graph reveals that the pressure drop values for the pre-flush stage range between approximately 35 psi and 125 psi, for polymer injection - from 75 psi up to 245 psi, and for post-flush - between 0 psi and 17 psi. Talking about the recovering factor results, the recovery factor reaches 43% of the original oil in place (OOIP) after flooding with seawater only and continued by an additional recovery of about 47% after polymer injection, giving up to 90% recovery in total for Caspian seawater with polymer flooding test.

Resistivity factor (RF) and residual resistivity factor (RRF) have been also easily estimated based on the pressure drop data for each flooding stage to assess the injectivity of the fluids. RF is expressed as the ratio of stabilized pressure drop during polymer flooding to stabilized pressure drop during water flooding (pre-flush). The residual resistivity factor, in turn, is defined as the ratio of stabilized pressure drop during post-flush to the stabilized pressure drop during pre-flush.

RRF is expected to be close to 1 if no pore plugging occurred during the polymer injection. The estimated RF and RRF results for Caspian seawater-based polymer flooding is presented in Table 5.

Table 5. Stabilized pressure drop at each flow rate and corresponding RF and RRF (for Caspian seawater case)

q [cc/min]	**Caspian seawater Flooding**	**Polymer Flooding**	**Post-flush**	**RF**	**RRF**
	ΔP [psi]				
0.5	39.9	81.1	3.5	2.03	0.09
1	48.8	134	8.3	2.75	0.17
1.5	53.5	181.8	13.4	3.40	0.25
2	72.7	212.5	18.4	2.92	0.25

Meanwhile, the collected effluents during polymer injection were tested for rheology. The initial viscosity of 2500 ppm polymer solution before the start of core flooding was 22.04 cp. The polymer degradation percentage in regards to the initial polymer viscosity is also calculated using Equation (2) and presented in Table 6.

Table 6 shows that a breakthrough during seawater-water-based polymer injection happens to start at about a third pore volume because the viscosity of the effluent is close to the polymer viscosity.

Table 6. Viscosity and mechanical degradation of seawater-based polymer during oil displacement test

q [cc/min]	PV	Viscosity [cp]	Degradation [%]
0.5	1	1.01	95.42
	2	1.36	93.81
	3	9.90	55.07
	4	16.14	26.77
	5	16.30	26.03
	6	16.32	25.95
	7	15.11	31.46
	9	18.02	18.23
1	11	15.70	28.78
	13	17.15	22.21
	15	15.31	30.55
1.5	17	11.80	46.45
	19	14.28	35.23
2	21	13.77	37.51
	23	15.33	30.45
	25	14.53	34.06
	27	16.06	27.12

4.1.2. Oil Displacement test with Alb water

Exactly the same procedure as in the case of Caspian seawater injection was followed for the case of Alb water flooding followed by Alb water-based polymer injection with Alb water post-flush to obtain the results presented in Figure 39. The calculations of PV, S_{wi}, ϕ, V_{oi} and recovery factor for each injected PV have been also performed accordingly:

$$PV = \frac{141.28\ g - 124.47\ g}{1.1\ g/cc} = 15.3\ cc$$

$$S_{wi} = \frac{15.3\ cc - 11.4\ cc}{15.3\ cc} \times 100\% = 25.5\%$$

$$V_b = 5.7\ cm \times \left(\frac{3.78\ cm}{2}\right)^2 \times \pi = 63.97\ cc$$

$$\phi = \frac{15.2\ cc}{63.97\ cc} = 0.238 = 23.8\%$$

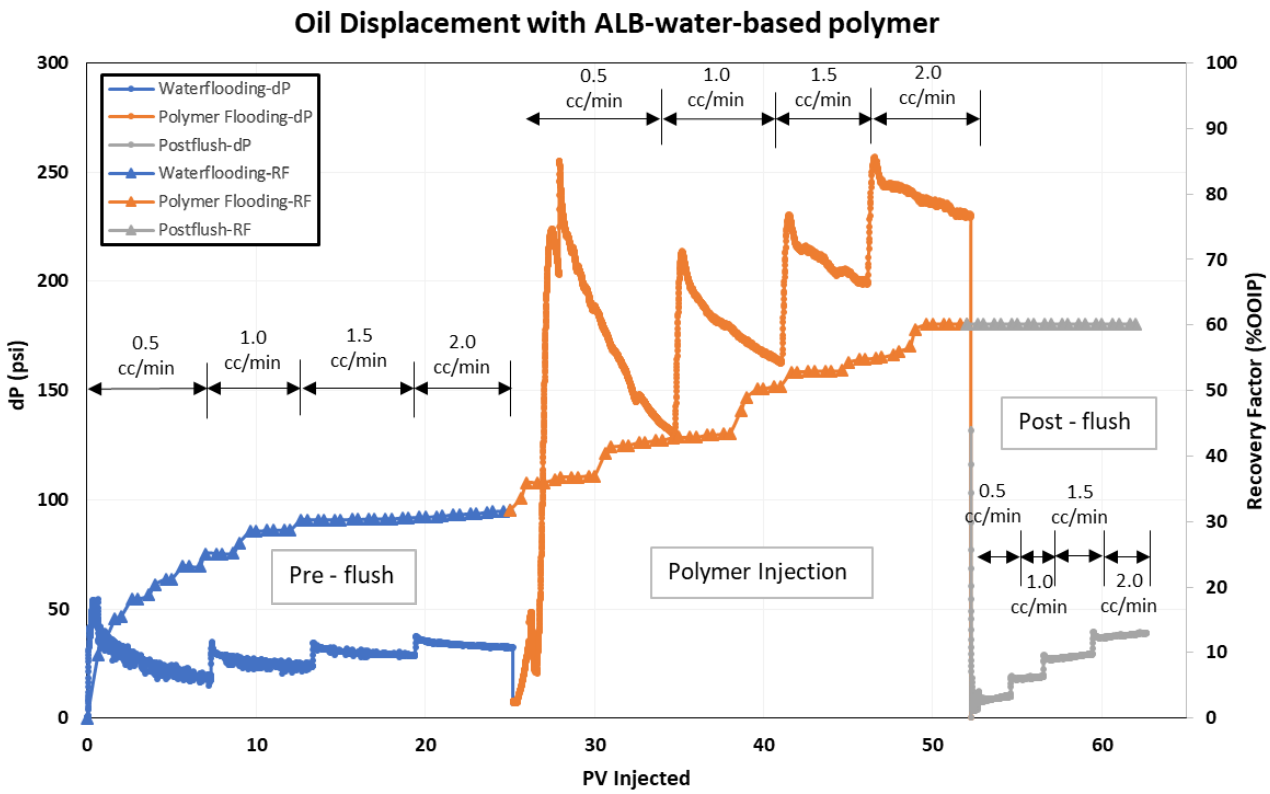

Figure 39. Oil displacement test with polymer based on Alb-water

According to Figure 39, pressure drop during Alb water pre-flush ranged between approximately 20 psi and 55 psi, during polymer injection - between 125 psi and 255 psi, and reached up to 40 psi during post-flush. Meanwhile, the oil recovery for water flooding with Alb water reached only about 31% OOIP and an additional recovery of 29% OOIP by Alb water-based polymer injection.

RF and RRF for Alb water-based polymer case is also estimated for comparison with the seawater case and presented in Table 7.

Table 7. Stabilized pressure drop at each flow rate and corresponding RF and RRF (for Alb water case)

q [cc/min]	Alb water Flooding	Polymer Flooding	Post-flush	RF	RRF
	ΔP [psi]				
0.5	18.6	131	10	7.04	0.54
1	23.9	163.5	18.8	6.84	0.79
1.5	28.5	200	28.7	7.02	1.01
2	32.5	230.8	38.7	7.10	1.19

Turning to the rheology of the effluents, the recorded viscosity values are presented in Table 8, as well as the calculated polymer degradation percentage in regards to the initial viscosity of the polymer. The initial viscosity of Alb water-based polymer was 21.91 cp.

Table 8 shows that a breakthrough during seawater-based polymer injection happens after the third pore volume because the viscosity of the effluent is close to the polymer viscosity.

Table 8. Viscosity and mechanical degradation of Alb water-based polymer during oil displacement test

q [cc/min]	PV	Viscosity [cp]	Degradation [%]
0.5	1	2.07	90.56
	2	12.03	45.09
	3	17.92	18.24
	7	18.17	17.10
1.5	17	19.19	12.41
2	21	20.63	5.85
	23	20.08	8.37
	25	19.34	11.74

4.1.3. Discussion

From the obtained high recovery data for polymer injection in both Caspian seawater (~47%) and Alb water (~29%), it can be clearly stated that polymer injection in the Uzen field can result in high oil production. However, to get the highest efficiency from the application of this chemical EOR method, each case should be analyzed in detail.

First, the pressure drop data for each case can be discussed. Figures 38 and 39 show that the pressure drop during the pre-flush by seawater injection is about twice higher as in the case of pre-flush by Alb water. This difference reveals that the injectivity of seawater is lower during water flooding than during Alb water flooding. The possible reason for this could be the high contamination of solid particles, microorganisms, metals, and other elements in Caspian seawater. Although the water was filtrated with 30 μm pore-sized filter paper, unfiltered microparticles can be large enough to harden the water flow in the formation pore scale and require a higher pressure drop to be injected.

Moreover, despite the fact that the pressure drop during seawater flooding was higher than Alb water flooding, calculated resistivity factors presented in Tables 5 and 7 are inversed for these two cases. To be exact, the resistivity of polymer to the flow of Alb water was higher than in the case of Caspian seawater. As a result, the pressure drop for seawater polymer flooding became even lower than for Alb water-based ones. The possible reason for such a difference between the two cases can be investigated by looking at calculated polymer degradation data (Tables 6 and 8). Considering the polymer degradation values after the polymer breakthrough, high polymer degradation in the seawater-based polymer case - from 18% up to 46%- is observed. Meanwhile, for Alb water-based polymer degradation value after the polymer breakthrough ranges between 5% and 18%. Thus, it can be concluded that lower viscosity of polymer required lower pressure drop and compensated high-pressure drop during water flooding by seawater.

Further analyzing the rheology data in Tables 6 and 8, it should be noted that during Alb-water polymer injection the breakthrough happens faster than with seawater-based one. Alb-water polymer moves faster through the core and reaches the end of the core quicker, so that much of the polymer didn’t propagate deep into all of the pores, leaving more unswept area in the formation. On the other hand, seawater-based polymer showed better performance during the injection because the breakthrough doesn't happen as fast as with Alb-water one meaning more oil could be produced using seawater-based polymer.

The results of the recovery factor also prove the fact that possible oil production by seawater-based polymer, being about 47% OOIP, is higher than oil production by Alb-water-based polymer, which is about 29% OOIP. In total, a recovery factor of 91% with seawater as the pre-flush and seawater-based polymer (Figure 38) over 60% with Alb-water as the pre-flush and Alb-water-based polymer (Figure 39) was obtained.

Meanwhile, looking solely at the oil recovery by water flooding, seawater as the pre-flush showed better performance rather than Alb-water. Despite the fact that the former required a higher pressure drop, it resulted in a recovery factor of 43% OOIP (Figure 38), while Alb-water produced only 31% OOIP (Figure 39), respectively. This phenomenon could be possibly explained by a higher concentration of divalent ions such as Ca^{2+} and Mg^{2+} (Table 3), which affect the detachment of oil molecules from the rock surface. Table 3 shows that seawater has 363.3 ppm of Ca^{2+} and 809 ppm of Mg^{2+}, while Alb-water has 179.9 ppm of Ca^{2+} and 84.07 ppm of Mg^{2+}, respectively. The higher the concentration of divalent ions like Ca^{2+} and Mg^{2+}, the bigger the detachment of the oil from the rock surface becomes. However, it is also important to note that such divalent ions can negatively affect polymer degradation.

To sum up, based on this difference in recovery factors, it was decided that Caspian seawater as the pre-flush, followed by injection of the polymer prepared with the seawater shows greater performance in comparison to the Alb-water case.

Chapter 5

5.1. Conclusion and Recommendations

The main aim of this research was to evaluate the oil displacement in the Uzen field using different types of polymer and compare the results to decide what polymer shows better performance. The following objectives have been accomplished during this research: oil displacement tests have been conducted by using Caspian seawater and Alb water; the recovery, injectivity, and polymer degradation factors of the oil displacement tests have been calculated and evaluated to determine the most suitable polymer. Based on the experimental results and further discussion it was concluded that although both tests presented recovery of 60% OOIP and higher in total after water and polymer flooding, 2500ppm Polymer 3 solution prepared with Caspian seawater works better than Alb-water-based polymer.

The next step of this research would be conducting polymer injection in the field scale through the pilot project by injecting seawater-based polymer and monitoring the performance of the polymer in real conditions. Nevertheless, further research can be also made on the relative permeability of the fluids to better understand the flowing behavior of the fluids. Additionally, the significance of the effect of divalent cations on both oil detachment ability and polymer degradation can be further investigated.

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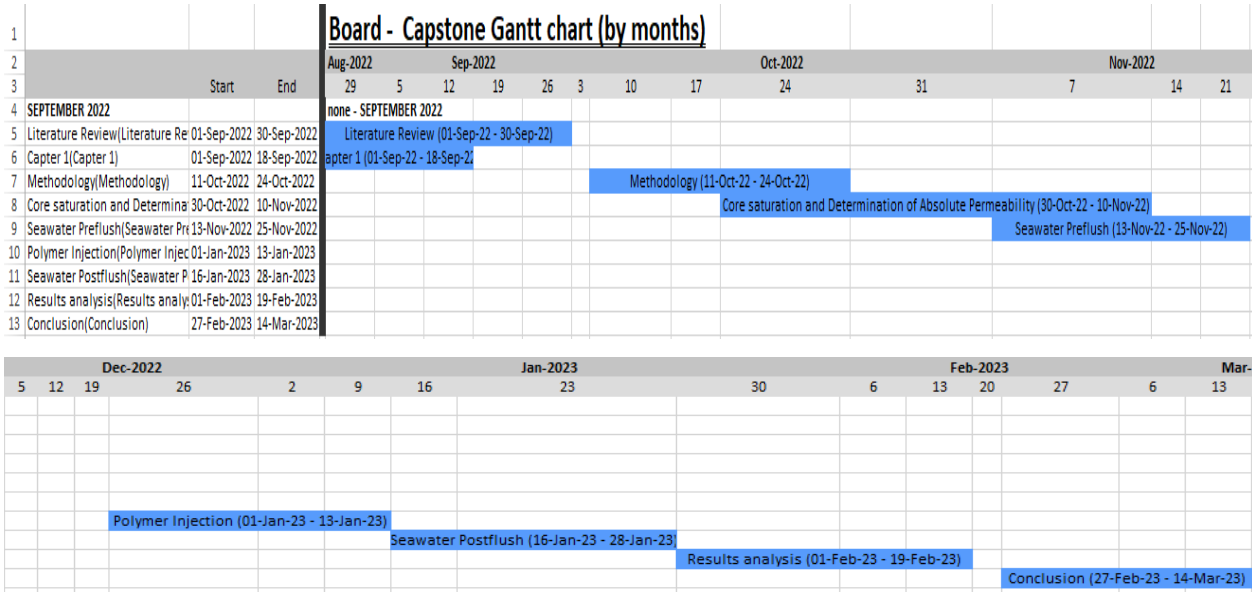
Appendix A: Gantt Chart



Appendix B: Produced oil volumes in the effluents and calculated oil recovery factor with PV of injected fluid

PV	Vo [cc]	Cum. Vo [cc]	Recovery Factor [%]
0	0	0	0
0.132	1	1	8.22
0.263	0.1	1.1	9.05
0.395	0.08	1.18	9.70
0.526	0.07	1.25	10.28
0.658	0.05	1.3	10.69
0.789	0.15	1.45	11.92
0.921	0.1	1.55	12.75
1.000	0.1	1.65	13.57
1.658	0.7	2.35	19.33
2.000	0.1	2.45	20.15
2.658	0.25	2.7	22.20
3.000	0.2	2.9	23.85
3.658	0	2.9	23.85
4.000	0.1	3	24.67
4.658	0	3	24.67
5.000	0.35	3.35	27.55
5.658	0.1	3.45	28.37
6.000	0.3	3.75	30.84
6.658	0.2	3.95	32.48
7.000	0	3.95	32.48
7.658	0	3.95	32.48
8.000	0	3.95	32.48
8.658	0	3.95	32.48
9.000	0	3.95	32.48
9.658	0.3	4.25	34.95
10.000	0	4.25	34.95
10.658	0.15	4.4	36.18
11.000	0	4.4	36.18

PV	Vo [cc]	Cum. Vo [cc]	Recovery Factor [%]
11.658	0	4.4	36.18
12.000	0	4.4	36.18
12.658	0.25	4.65	38.24
13.000	0	4.65	38.24
13.658	0	4.65	38.24
14.000	0	4.65	38.24
14.658	0	4.65	38.24
15.000	0.25	4.9	40.30
15.658	0.1	5	41.12
16.000	0.05	5.05	41.53
16.658	0.1	5.15	42.35
17.000	0.05	5.2	42.76
17.658	0.2	5.4	44.41
18.000	0.3	5.7	46.88
18.658	0.45	6.15	50.58
19.000	0.4	6.55	53.87
19.658	0.2	6.75	55.51
20.000	0.2	6.95	57.15
20.658	0.2	7.15	58.80
21.000	0.45	7.6	62.50
21.658	0.05	7.65	62.91
22.000	0.3	7.95	65.38
22.658	0.3	8.25	67.85
23.000	0	8.25	67.85
23.658	0.4	8.65	71.13
24.000	0.3	8.95	73.60
24.658	0.08	9.03	74.26
25.000	0	9.03	74.26
25.658	0.02	9.05	74.42
26.000	0.3	9.35	76.89
26.658	0.01	9.36	76.97
27.000	0.01	9.37	77.06

PV	Vo [cc]	Cum. Vo [cc]	Recovery Factor [%]
27.658	0.02	9.39	77.22
28.000	0.2	9.59	78.87
28.658	0.008	9.598	78.93
29.000	0	9.598	78.93
29.658	0.1	9.698	79.75
30.000	0.2	9.898	81.40
30.658	0	9.898	81.40
31.000	0.02	9.918	81.56
31.658	0.2	10.118	83.21
32.000	0	10.118	83.21
32.658	0.04	10.158	83.54
33.000	0	10.158	83.54
33.658	0	10.158	83.54
34.000	0.08	10.238	84.19
34.658	0.08	10.318	84.85
35.000	0.1	10.418	85.67
35.658	0.2	10.618	87.32
36.000	0.01	10.628	87.40
36.658	0	10.628	87.40
37.000	0	10.628	87.40
37.658	0	10.628	87.40
38.000	0.01	10.638	87.48
38.658	0.02	10.658	87.65
39.000	0.02	10.678	87.81
39.658	0.15	10.828	89.05
40.000	0	10.828	89.05
40.658	0.1	10.928	89.87
41.000	0.01	10.938	89.95
41.658	0.05	10.988	90.36
42.000	0.01	10.998	90.44
42.658	0.05	11.048	90.86
43.000	0.007	11.055	90.91

PV	Vo [cc]	Cum. Vo [cc]	Recovery Factor [%]
43.658	0	11.055	90.91
44.000	0	11.055	90.91
44.658	0	11.055	90.91
45.000	0	11.055	90.91
45.658	0	11.055	90.91
46.000	0	11.055	90.91
46.658	0	11.055	90.91
47.000	0	11.055	90.91
47.658	0	11.055	90.91
48.000	0	11.055	90.91
48.658	0	11.055	90.91
49.000	0	11.055	90.91
49.658	0	11.055	90.91
50.000	0	11.055	90.91
50.658	0	11.055	90.91
51.000	0	11.055	90.91
51.658	0	11.055	90.91
52.000	0	11.055	90.91
52.658	0	11.055	90.91