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Abstract

As the demand for energy continues to rise, it becomes increasingly crucial to identify effective methods for recovering oil resources that remain after initial production. This underscores the significance of Enhanced Oil Recovery (EOR) research. EOR techniques play a vital role in optimizing hydrocarbon extraction from aging reservoirs; however, the efficacy of these techniques is frequently compromised by inconsistencies arising from laboratory studies. Such inconsistencies can be attributed to various factors, including rock preparation methods, temperature, pressure, and experimental protocols and reliance on the capillary number.

In this investigation, the effect of pressure, viscosity, and interfacial tension (IFT) was investigated, and an experimental analysis to compare two commonly employed injection methods—constant rate injection and constant pressure injection—to assess their respective effects on recovery results was conducted. Our results reveal significant differences in recovery efficiency between these two approaches, highlighting the need for optimization of EOR protocols tailored to specific reservoir conditions. This research emphasizes the necessity of standardized rock preparation techniques and the judicious selection of injection methods to enhance the precision and efficacy of EOR applications.

Chapter 1: Introduction: background and objectives

1.1. Enhanced Oil Recovery (EOR)

Enhanced Oil Recovery (EOR), also known as tertiary recovery, is the process of extracting oil from a reservoir that has gone through primary and secondary recovery techniques. Primary and secondary recovery allow to obtain an oil recovery between 20% to 40 % on average, with EOR increasing this percentage to between 50% and 80% by targeting the residual oil saturation (Muggeridge et al. 2014). EOR involves altering the properties of the reservoir, hence the importance for the operator to obtain as much information as possible about the targeted reservoir. EOR methods include techniques such as waterflooding, polymer flooding, surfactant flooding, and gas injection that are widely used methods and have been successfully used in different basins around the world. **Figure 1** below shows the different methods used in EOR and their classifications (Thomas 2008).

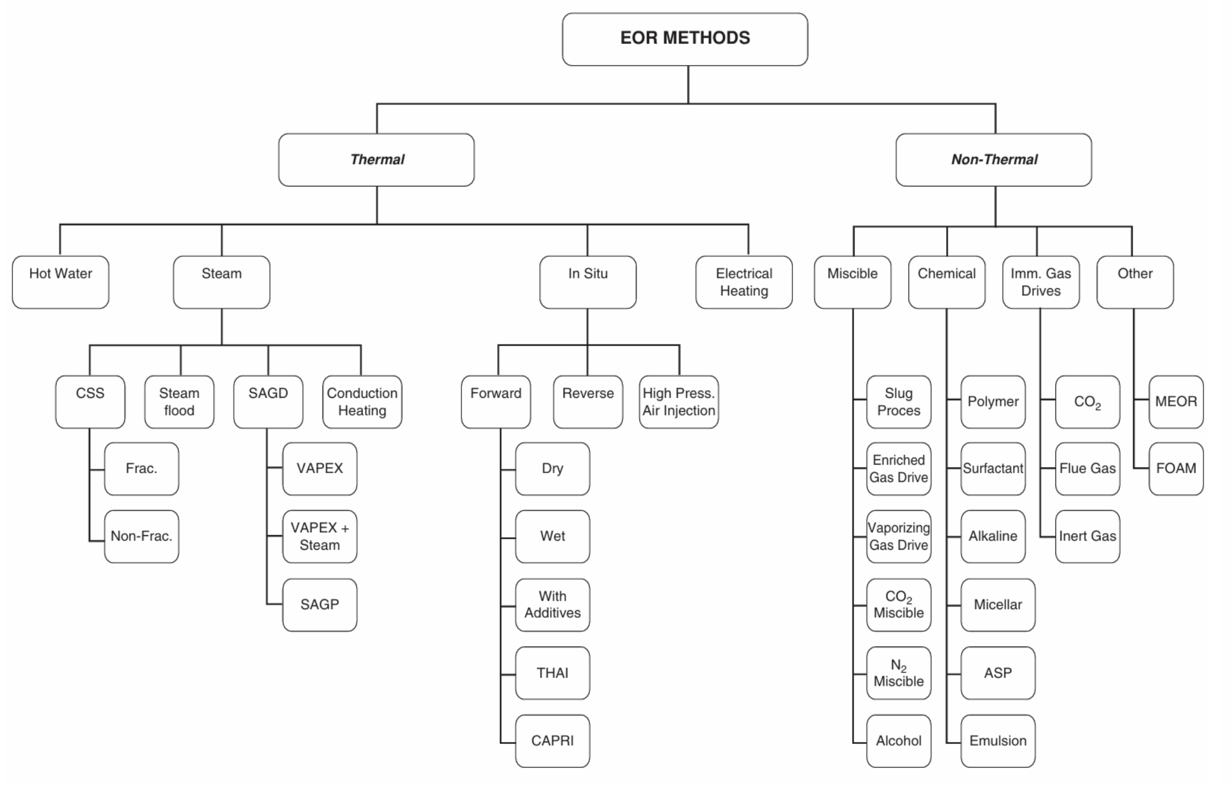

Figure 1 Classification of EOR methods (Thomas 2008)

Laboratory studies and testing are necessary to ensure the success of the EOR process within the context of a specific reservoir system. New EOR methods can also be developed during such studies which can be explored using simulations and testing on rock samples with conditions and parameters that mimic those of the field.

1.2. Research Motivations and Research Hypothesis

With growing global energy demands and rising costs, there is now greater pressure to develop efficient resource extraction methods and develop new recovery technologies. As mentioned earlier, only about 20% to 40% of the Original Oil In Place (OOIP) is recovered after primary and secondary recovery methods are used. Improving the ability to extract more oil from existing reservoirs is critical for meeting future energy needs. EOR or tertiary recovery is essential for sustaining oil production throughout the life of a well and for maximizing the amount of oil extracted from the reservoir as it can increase recovery to 80% when optimized.

Many EOR laboratory studies do not use conditions and parameters that are representative of real field conditions, and this can result in misleading conclusions and failed field applications. With the motivation of better understanding the mechanisms that impact the efficiency EOR methods and developing a protocol for EOR studies in a laboratory setting, this study aims to investigate the parameters that can affect EOR by studying the effect of pressure, flow rate, fluid properties, and capillary number, and comparing two methods that are the constant rate injection and the constant pressure injection.

1.3. Objectives of study

In order to investigate key parameters that affect EOR studies in the laboratory setting and identify potential challenges that can arise in such studies, core flooding experiments were conducted with consistent testing conditions throughout the research. The objective of the study was to investigate physical properties affecting EOR studies by accomplishing the following:

- Investigate the effects of injection rate on oil recovery
- Investigate the effects of capillary number by varying parameters such as viscosity and interfacial tension along with pressure and rate changes
- Compare constant pressure injection and constant rate injection methods

1.4. Research Outline and Scope of Study

For this study, and to achieve the objectives cited in the previous section, a literature review was done followed by experimental work. The scope and methodology are described as follows:

1. Literature review: An extensive and in-depth literature review on EOR methods and their studies and use in the field was performed. The review process included but was not limited to analysis of journal articles, conference proceedings, and other technical publications
2. Experimental work: Multiple sets of experiments, including rock characterization, and core flooding experiments, were conducted to determine the best method to use when studying EOR in a laboratory setting.

Chapter 2: Literature Review of Laboratory EOR Studies

2.1 Introduction

Enhanced oil recovery (EOR) techniques have gained significant importance in response to the increasing global energy demand and the depletion of conventional oil reserves. Conventional primary and secondary recovery methods often leave a substantial amount of oil trapped within reservoirs, underscoring the necessity of EOR techniques to optimize resource extraction from aging fields. EOR encompasses various methods, including thermal, chemical, and gas injection processes, which are designed to enhance oil displacement and mobility, thus augmenting the volume of recoverable oil. Nevertheless, despite technological advancements in EOR, there are ongoing challenges in refining these methods to achieve both cost-effectiveness and high recovery efficiency. A prominent challenge in EOR research is the variability stemming from differences in rock preparation, injection methodologies, and the intricate interactions between reservoir fluids and geological formations.

2.2 EOR Methods in Conventional Reservoirs

2.2.1 Thermal EOR Methods

Thermal EOR methods have been used in the oil and gas industry for a long time and are widely used in the world. These methods introduce heat into a reservoir to improve oil mobility by lowering its viscosity, making it flow more easily toward the production wells and increase extraction rates (Muggeridge et al. 2014, Speight 2009, Thomas 2008). Thermal EOR is mainly used in heavy oil reservoirs where the oil is thick, viscous, and difficult to move. There are several methods within thermal EOR, each with their advantages and limitations such as high energy and operational costs (Mokheimer et al. 2019).

Steam Flooding: Also known as “steam drive” and shown on **Figure 2**, is a method which consists of continuously injecting steam into the reservoir via dedicated injection wells. The heat from the steam reduces oil viscosity resulting in better oil mobility. This method has been commercially used since the 1960s and requires the reservoir to have a porosity of at least 20%, a permeability of 100 mD, and an oil saturation of at least 40% (Speight 2009).

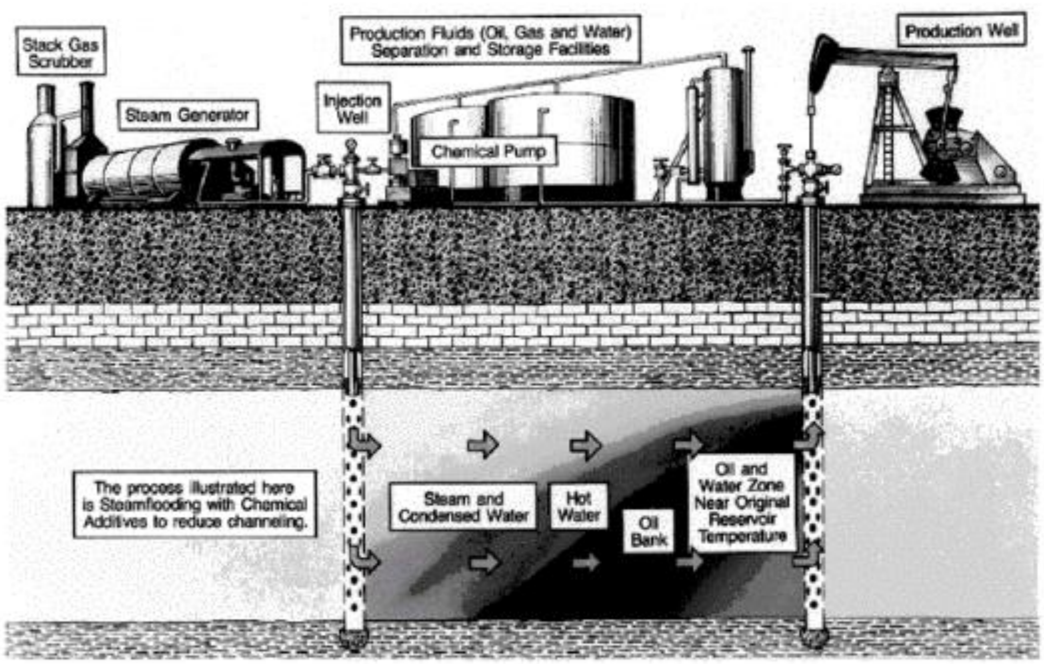

Figure 2- Oil recovery by Steam injection (Speight 2009)

Cyclic Steam Stimulation (CSS): Also known as the "huff-and-puff" method and is done in three stages using one well. The first stage is the injection of steam, then soaking (shutting it in the well to allow heat to permeate the reservoir), and the final stage of production, where oil is produced from the same well.

Steam-Assisted Gravity Drainage (SAGD): Developed by Butler in 1985 as a method to recover Alberta bitumen (Butler 1985). SAGD involves drilling two horizontal wells (one above the other). Steam is injected into the upper well, which heats the oil and lowers its viscosity allowing it to drain into the lower well by gravity for production. This method is particularly effective in thick, heavy oil reservoirs where traditional methods may not be viable (Butler 1985, Thomas 2008).

In-Situ Combustion (ISC): Also known as "fire flooding," this method consists in injecting air or oxygen into the reservoir to ignite a portion of the oil. The combustion can be done in a forward or reverse direction and the heat generated by the combustion reduces the viscosity of the surrounding oil, helping it flow more easily (Mahinpey et al. 2007, Thomas 2008).

Hot Water Injection: Hot water injection is less commonly used than steam injection, but it is sometimes applied when lower temperatures are adequate for reducing viscosity. Hot water injection has fewer operational challenges than steam, though it is less effective for highly viscous oils.

2.2.2 Non-Thermal Methods

Non-thermal methods are mainly used for reservoirs with lighter oil and where thermal methods are not suitable. These methods are selected and optimized through extensive laboratory studies with the objective to lower the interfacial tension (IFT) and to improve the mobility ratio. Some of the non-thermal EOR methods include chemical flooding shown on **Figure 3** below (such as polymer, surfactant, alkaline-surfactant-polymer), gas flooding, and microbial EOR (Thomas 2008).

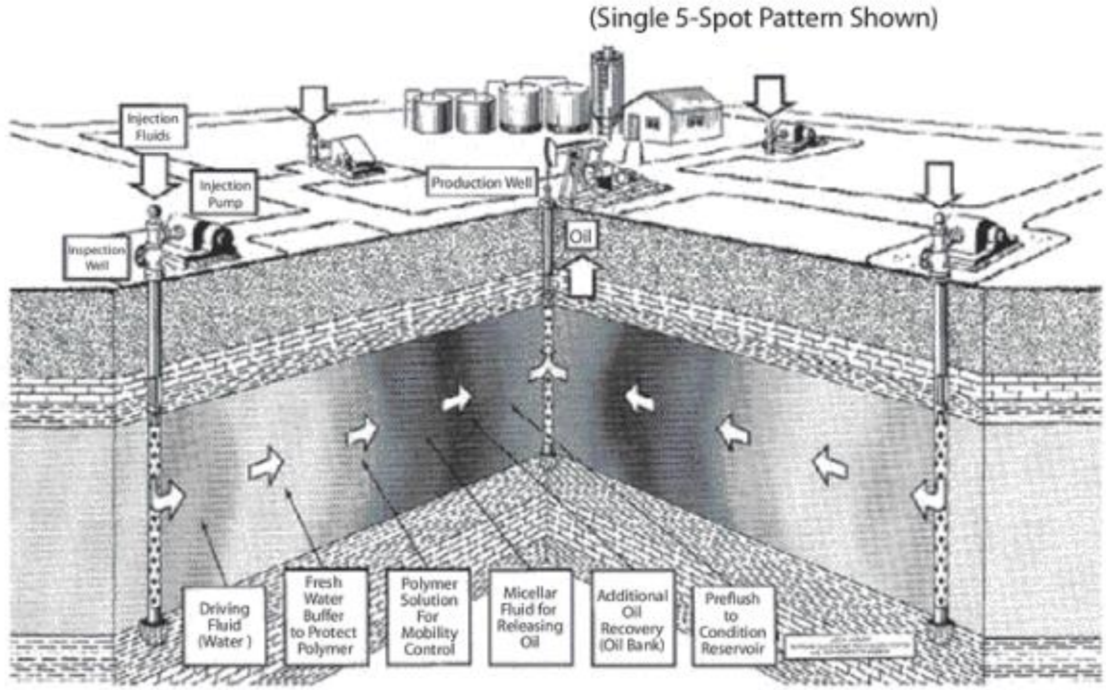

Figure 3- Chemical Enhanced Recovery Processes (Speight 2009)

Polymer Flooding: This method involves injecting water mixed with polymers to increase the water's viscosity. The thicker water helps sweep more oil toward the production well by improving the "mobility ratio" between water and oil, making oil recovery more efficient. It can also be combined with other methods such as surfactants, nanoparticles, and low salinity water flooding (Kakati et al. 2022, Pogaku et al. 2018, Shaker Shiran and Skauge 2013).

Surfactant Flooding: Surfactants, or detergents, reduce the interfacial tension between oil and water. This enables the trapped oil to be released from rock surfaces, allowing it to flow more easily to production wells. Other mechanisms allowing higher oil recovery are emulsification and wettability alteration (Al-Azani et al. 2022).

Alkaline-Surfactant-Polymer (ASP) Flooding: ASP combines the benefits of alkaline, surfactant, and polymer flooding. The alkaline chemical helps create surfactants in situ by reacting with acidic components in the oil, while polymers improve sweep efficiency and surfactants lower interfacial tension. Although ASP flooding has many issues such as scaling, cost, and alkaline environment, it can be highly effective but requires careful management of chemical concentrations to optimize recovery (Liu et al. 2020).

Gas Injection: Gas flooding can be divided into two categories that are miscible and immiscible gas injection. In miscible gas injection, gases such as carbon dioxide (CO_2), nitrogen, or methane are injected at high pressure to dissolve into the oil. This creates a "miscible" phase where the oil and gas mix, effectively reducing oil viscosity and swelling the oil, making it flow more easily toward the production wells.

In immiscible gas injection, gas is injected at lower pressures and does not dissolve into the oil. The gas instead pushes the oil toward production wells by increasing reservoir pressure. While less effective than miscible injection, it can still improve recovery. Gas flooding can also be combined with other EOR methods to further improve oil recovery (Ozowe et al. 2024).

When it comes to gas injection, CO_2 injection is a widely studied and applied EOR methods due to its effectiveness and environmental benefits. Injecting CO_2 into reservoirs helps reduce atmospheric CO_2 while improving oil recovery by both swelling the oil and reducing its viscosity. CO2 is also used in geothermal reservoirs as a geofluid (Erol et al. 2022, Gudala et al. 2024, Manrique et al. 2010, Perera et al. 2016)

Water-Alternating-Gas (WAG) Injection: WAG involves alternating between water and gas injection to maintain reservoir pressure and improve sweep efficiency. This method can help mitigate the "fingering" of gas through the oil, a common issue in gas injection alone, ensuring a more uniform displacement of oil and increasing recovery rates. WAG can be used with either CO_2 or other gases, depending on reservoir conditions.

Microbial EOR (MEOR): Microbial EOR uses specific bacteria or nutrients injected into the reservoir to promote the growth of microbes that produce biosurfactants, gases, or acids. These byproducts help reduce oil viscosity, decrease interfacial tension, and create pathways for oil to flow more easily. MEOR is considered an environmentally friendly method, as it uses natural processes, but it requires precise control to ensure optimal results (Maudgalya et al. 2007, Patel et al. 2015).

2.3 EOR Studies Approaches

To study EOR, understanding the equations that govern the flow of multiple phases inside porous media as well as factors that can influence the mobilization of residual oil is a must. The most common equation used when it comes to studying flow through porous media is Darcy's law (Equation (1)):

$$\frac{q}{A} = -\frac{k}{\mu}\frac{dp}{dx} \tag{1}$$

Where q is the flow rate (cc/s), A the surface area (cm^2), k the permeability (D), μ the viscosity (cp). It says that the velocity of the fluid (represented by q/A on the left of the equation) is proportional to the pressure gradient (atm/cm) across the rock (dp/dx). The parameters that control the relation between pressure and velocity are: The property of the fluid itself (viscosity) and The property of the rock (permeability).

When it comes to multiphase flow in a rock, the flow of each phase is restricted by the other phases. As the saturation of the water or gas phases is increased and the oil saturation decreases, the resistance for oil to flow increases until oil no longer flows at its residual oil saturation (Sor) (Johns 2004). Resistance to flow is measured by the relative permeability which is the ratio of the ratio of the effective permeability of a fluid to the absolute permeability of the rock (Honarpour and Mahmood 1988). The effect that these parameters have on EOR and the role they play will be discussed in the following sections.

There are several steps taken before the implementation of an EOR method in the field that are shown on **Figure 4**. First, the reservoir is assessed to determine the appropriate method that can be used, then laboratory studies and simulation are done to have the best design for the targeted reservoir, followed by pilot tests and field implementation (Karović-Maričić et al. 2014).

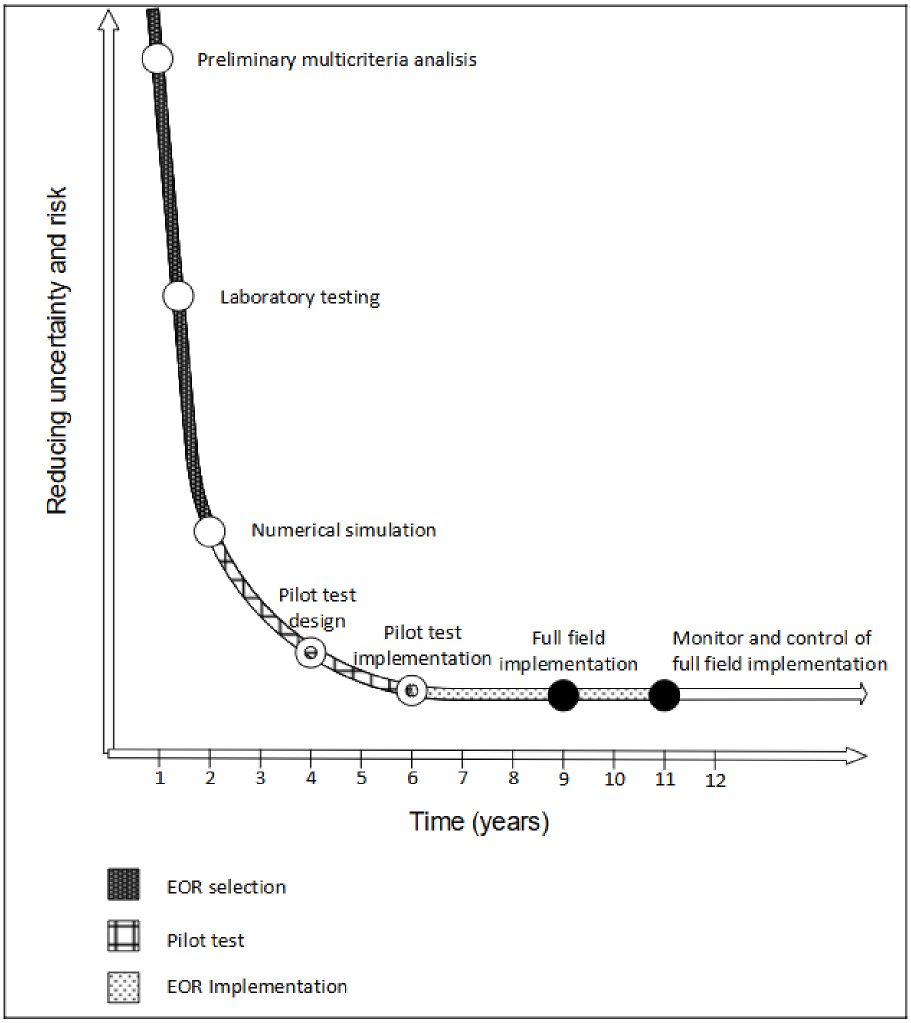

Figure 4- Phases of EOR **Implementation (Karović-Maričić et al. 2014)**

2.3.1 Experimental Studies

Core flooding experiments are the got-to methods used to study EOR in a laboratory setting (Goodlett et al. 1986, Isah et al. 2022, Manrique et al. 2010, Yekeen et al. 2018). They simulate fluid flow through a reservoir rock by injecting fluids through a core sample. During these tests, the pressure is monitored using a transducer. The produced fluid is also monitored to determine how much oil was recovered from the rock.

Core flooding tests are simple experiments but must involve careful sample preparation and choices for the method of injection as they have a great impact on the results obtained and the conclusions made. The rock and fluid selected need to be representative of the targeted reservoir. Parameters such as temperature, pressure, and wetting condition between the oil, water, and rock should also match that in the reservoir. In addition, the injection rate and pressure gradient of injection need to be equivalent to what is expected in the field, and this can be done by matching the "velocity" of the fluid in target region of the reservoir.

Another method used to study EOR is the microfluidics method which consists of using glass micromodels that mimic a reservoir pore structure. The material used is also coated to match the reservoir rock mineralogy and require low volumes of fluid for the experiments (Fani et al. 2022, Gogoi and Gogoi 2019, Li and Torsæter 2014, Lifton 2016, Mohajeri et al. 2015).

2.3.2 Simulation Studies

Based on experimental data, simulations are used to model entire reservoirs, taking into consideration the geology, fluid flow, and rock properties (Chen et al. 2024) and are said to be cost and time effective. Simulations are also used to study the behavior of fluids at interfaces in order to understand phase behavior and displacement mechanisms (Fu et al. 2022), as well as the effect of capillary number and relative permeability (Suwandi et al. 2022) . When it comes to chemical EOR methods, they can be studied and optimized using software such as CMG-STARS, UTCHEM, and ECLIPSE, with CMG-STARS and ECLIPSE being the best simulators (Goudarzi et al. 2016). These have been used to investigate the mechanisms of processes such as polymer flooding (Mohsenatabar Firozjaii and Saghafi 2020), and CO_2 injection (Zhou et al. 2019).

2.3.3 Field Cases

EOR methods play a vital role in increasing production and expanding the life of a well. Its market was estimated at USD 49,835.3 million in 2024 and is projected to grow in the upcoming years in a report made by Grand View Research. With rising costs, there is more pressure to run successful field applications, which is not always the case. Challenges such as high costs, facilities limitations, working condition not met for the method to work, and scaling issues (from laboratory to field) are met (Liu et al. 2020). In the case of polymer flooding, Lu et al. reported challenges such as a decrease in the oil increased per ton of polymer used when moving pilot test to a larger scale leading to lower economic feasibility (Lu et al. 2021). In the case of low salinity water flooding (LSWF) for example, numeral studies have been done on the topic but the lack of consensus in the literature on dominant mechanisms that can explain the improve recovery, the effect of brine on clay stability (clay destabilization may occur and potentially cause formation damage), and more, have been found to hinder its effectiveness and widespread application (Katende and Sagala 2019). Some of the mechanisms that are at play are interface interactions between the low salinity brine and reservoir brine. While we typically think of interfaces as existing between immiscible phases, miscible liquids also form interfaces that exhibit properties similar to those of immiscible liquids, such as surface tension. These interfaces, however, are dynamic and change over time due to the ongoing mixing process. The study of miscible interfaces poses numerous challenges. A key difficulty is the need to measure and quantify transient properties, like dynamic surface tension and interfacial diffusion rates. The complex interplay of various physical phenomena, such as diffusion, convection, and hydrodynamic instabilities, adds to the complexity (Shi and Babadagli 2019, Vorobev 2014, Zagvozkin et al. 2019).

2.4 Effect of Capillary Number on EOR Methods in Conventional Reservoirs

The capillary number plays a crucial role in EOR due to its significant impact on oil displacement mechanisms. It is defined as the ratio of viscous forces to capillary forces and is typically expressed by the following equation:

$$Ca = \frac{v\mu}{\sigma} \tag{2}$$

Where v is the Darcy velocity, μ is the viscosity of the displacing phase, and σ the interfacial tension (IFT) between wetting and non-wetting phase (Guo et al. 2020). At low Ca, capillary forces dominate viscous forces and high Ca, viscous forces dominate capillary forces. Guo et al int their review on the capillary number mentioned the challenge in precisely define the capillary number and reported on at least thirty-three (33) different definitions and equation with a few of them shown in **Table 1**.

Table 1- Capillary number expressions (Guo et al. 2020)

No.	Year	Authors	Porous media	Capillary Number
1	1935	Fairbrother and Stubbs	Capillary	$\sqrt{\frac{v\mu}{\sigma}}$
2	1939	Leverett	Sandstone	$\frac{LP_c}{D\Delta P}$
3	1947	Brownell and Katz	Sandstone	$\frac{K\Delta P}{gL\sigma\cos\theta}$
4	1953	Ojeda, Preston and Calhoun	Sandstone	$\frac{\sigma}{\Delta P}$
5	1953	Ojeda, Preston and Calhoun	Sandstone	$\frac{k\Delta P}{L\sigma}$
6	1955	Moore and Slobod	Sandstone	$\frac{v\mu}{\sigma\cos\theta}$
7	1958	Saffman and Taylor	Hele—Shaw Cell	$\frac{v\mu}{\sigma}$
8	1969	Taber	Sandstone Berea	$\frac{\Delta P}{L\sigma}$
9	1973	Foster	Sandstone Berea	$\frac{u\mu}{\sigma\phi}$
10	1973	Lefebvre duPrey	Teflon, Steel, and Aluminum	$\frac{KK_{rw}\Delta P}{\phi L\sigma}$

In a more recent review, Guo et al reported forty-one (41) expressions and noted potential inconsistencies between various applications and publications (Guo et al. 2022).

The capillary number helps quantify relative strength of viscous forces versus capillary forces in fluid flow and is important for capillary desaturation experiments, which are crucial for reservoir simulation and EOR strategy planning (Guo et al. 2022). Whith capillary desaturation experiment, the critical Ca- which is the number at which the number at which oil is mobilized- can be determined (Li et al. 2019). **Figure 5** shows a typical capillary desaturation curve. Typically this value is around 10^{-5} and can be affected by the scale of the system (Armstrong et al. 2014), and the wettability of the rock (Fulcher et al. 1985, Guo et al. 2017, Guo et al. 2020, Guo et al. 2022).

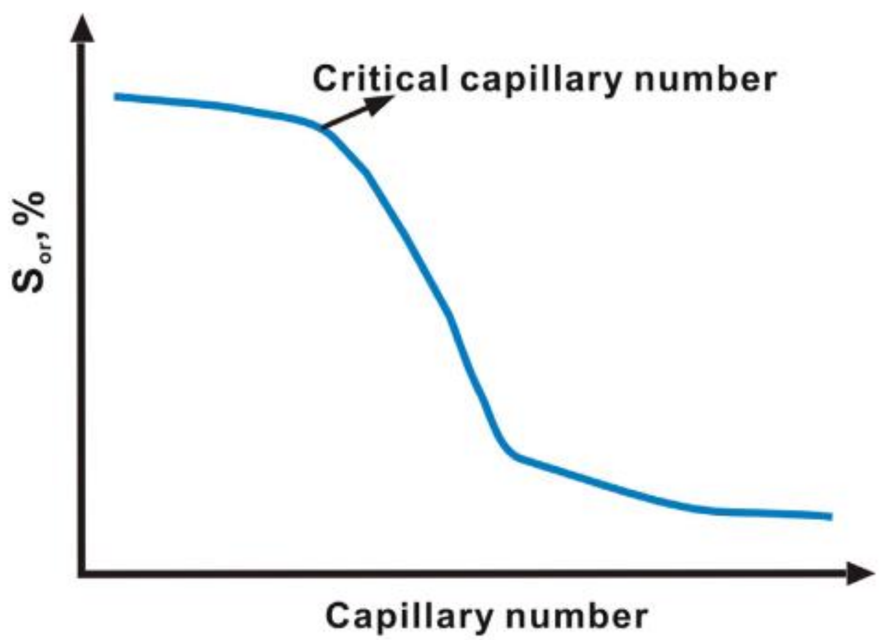

Figure 5- Typical capillary desaturation curve (CDC) (Li et al. 2019)

2.5 Effect Of Viscosity

Viscosity plays a crucial role in EOR processes, particularly in chemical flooding and waterflooding techniques. A change in viscosity can affect the sweep efficiency, capillary number, and pore-scale flow dynamics and understanding these effects is crucial for optimizing water flooding and chemical flooding techniques (Hou et al. 2006).

Increasing the viscosity of the displacing fluid improves capillary number, which is essential for mobilizing residual oil trapped in porous rock formations and can enhances displacement efficiency and sweep efficiency (Moore and Slobod 1955, Wang and Dong 2009). A viscosity that is too high on the other side, can create the adverse effect and reduce sweep efficiency (Walker et al. 2012).

2.6 Effect Of Porosity

Porosity is defined as the ratio of void spaces (pore volume) to the total volume of the rock, expressed as a percentage or fraction. Higher porosity indicates a greater volume of void spaces within the rock, allowing for more hydrocarbons to be stored within the reservoir. Different types of reservoir rocks exhibit varying porosity ranges: sandstone formations typically have porosities between 10% and 40%, while carbonate formations have porosities between 5% and 25%. (Muggeridge et al. 2014). A higher porosity can allow for better fluid displacement and sweep efficiency.

Porosity directly influences how easily fluids can move through a medium. High porosity means more void space for fluid movement, potentially increasing flow velocity. This can affect the capillary number since an increase in velocity can lead to higher capillary number values if other factors remain constant (Guo et al. 2022).

2.7 Effect Of Permeability

Permeability refers to the ability of a rock to transmit fluids through its pore spaces. It is typically measured in darcies or millidarcies and indicates how easily fluids can flow within the reservoir. High permeability allows for efficient fluid movement, which is crucial during EOR operations (Muggeridge et al. 2014).

The permeability of the rock to one of the fluids depends or relative permeability on the rock pore sizes and structure, but also depends on the saturation of fluid inside those pores and wettability (affinity between the rock and the fluid) (Xu et al. 2016). Heterogeneity of the rock can also have a negative impact on EOR leading to lower recovery (Zhong et al. 2021).

In systems where permeability is low, such as tight reservoirs or shales, capillarity tends to dominate due to smaller pore sizes leading to stronger surface tension effects relative to viscous forces. Conversely, in high-permeability systems like unconsolidated sands or well-fractured reservoirs, viscous forces can more easily overcome capillarity at lower pressure differentials due to larger pore throats facilitating easier movement (Muggeridge et al. 2014).

In summary, while permeability itself does not directly determine the capillary number, it significantly influences factors like velocity and flow regime that affect Ca. High permeability generally facilitates conditions where viscous forces can become dominant over capillarity at lower energy inputs compared to low-permeability settings.

2.8 Effect Of Pressure Drop

Pressure drop refers to the decrease in pressure that occurs as fluids move through porous media, such as oil reservoirs. In EOR processes, this can be caused by various factors including fluid

viscosity, reservoir permeability, and the injection of gases or water. The pressure gradient created by these factors influences how easily oil can be displaced from the rock matrix.
A higher pressure drop typically results in an increased flow rate of oil towards production wells(Muggeridge et al. 2014, Xu et al. 2016). However, if the pressure drop is too high, it may lead to issues such as formation damage or reduced injectivity. The ratio between the displacing fluid (e.g., water or gas) and displaced fluid (oil) affects how effectively oil can be swept towards production wells. An optimal mobility ratio minimizes viscous fingering and improves sweep efficiency.
It also affects the capillary number as it affects the driving forces behind fluid movement and can influence the balance between capillary and viscous forces (Moon and Migler 2009).

2.9 Research Gaps And Research Questions

While the capillary number is a convenient way to represent in a dimensional translatable equation the effect of a variety of parameters, it is not a highly reliable tool in determining relevant laboratory testing conditions. The inconsistencies in the literature when reporting laboratory results from polymer flooding or low-salinity waterflooding are examples of how the effect of various parameters on oil recovery go beyond its impact on the capillary number.

Ulasbek et al. in a recent paper studied the impact of nano-assisted polymer flooding in improving the total oil recovery rate. **Figure 6** shows graphs presenting the recovery factor % on the y axis, vs the number of pore volumes of fluids injected on the x axis. The conclusion of the paper said that an additional 26.9% recovery is obtained when non-assisted polymer flooding is used and were referring to the jump from 60% to 87% in the cumulative recovery factor that can be seen on **Figure 6.B**. However, there are multiple things to consider when looking at the graphs such as the increase in flow rate resulting in an additional recovery, which is common in laboratory settings and might not be representative of field conditions (Osoba et al. 1951). On **Figure 6.A**, it can be seen that there was no additional recovery after an increase in flow rate while injecting the nanofluid, but in the second case (**Figure 6.B**), the increase in injection rate resulted in increased recovery, which is mostly related to the higher pressure gradient obtained.

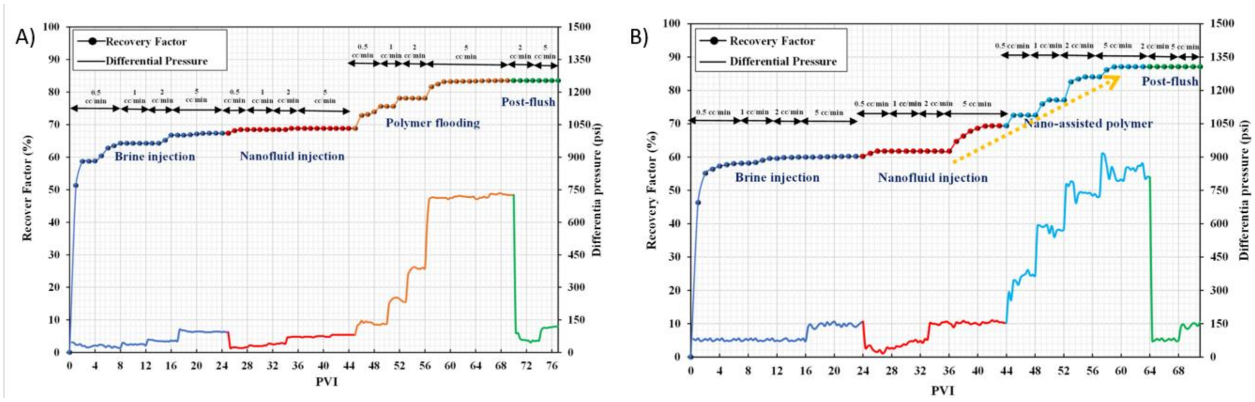

Figure 6- Recovery factors and differential pressure versus pore volumes injected (PVI) for core flooding experiments 2 (A) and 3 (B)(Ulasbek et al. 2022)

Another example would be this study by Wang et al. in which they were examining the impact of various polymer concentrations on enhanced recovery, **Figure 7.A** shows the pressure response from the 6 experiments they did, and **Figure 7.B** shows the recovery change. They used two different oils and three different polymer concentrations. Here experiments are done using constant rate injection, and they have no control over the pressure gradient. Accordingly, a pressure gradient of more than three times that obtained during water injection occurred during the polymer injection. In this case, the pressure gradients are in a reasonable range to be relevant to field conditions, however the results are still over-estimating the added effect of recovery when a polymer is added to the water.

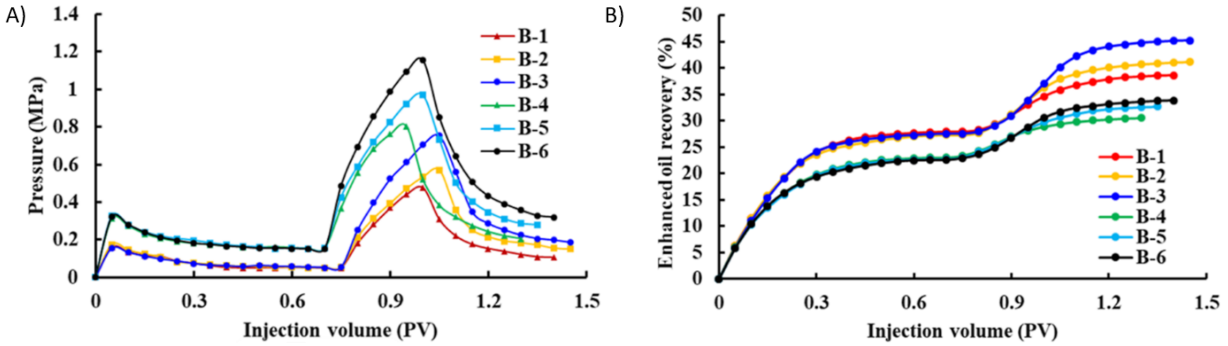

Figure 7- Pressure change curve (A), and recovery change curve (B) for polymer injection schemes (Wang et al. 2023)

The last example to be mentioned is a study by Tang and Firoozabadi. Their study is an example of a publication that considers the need to perform flooding experiments using constant pressure injection in order for the examples to be relevant to field conditions, especially when the wetting conditions are not the standard strongly water-wet case. On **Figure 8.A**, it can be seen that the injection of water towards enhanced oil recovery in a system that is strongly water-wet. In each of these cases, the pressure gradient is maintained constant. It shows that the recovery was not a function of pressure gradient in this case. Even when no pressure is imposed in the case of spontaneous imbibition, which utilizes capillary pressure as the driving force for displacement, the same ultimate recovery rate is obtained. On **Figure 8.B**, in the case of an oil-wet rock, changes in pressure, even when using the same injection fluid, results in different values in recovery rate. The least is using spontaneous imbibition resulting in 40% recovery, and that increases to 58% if 1 psi/cm is maintained, and to 68% if 4 psi/cm is maintained.

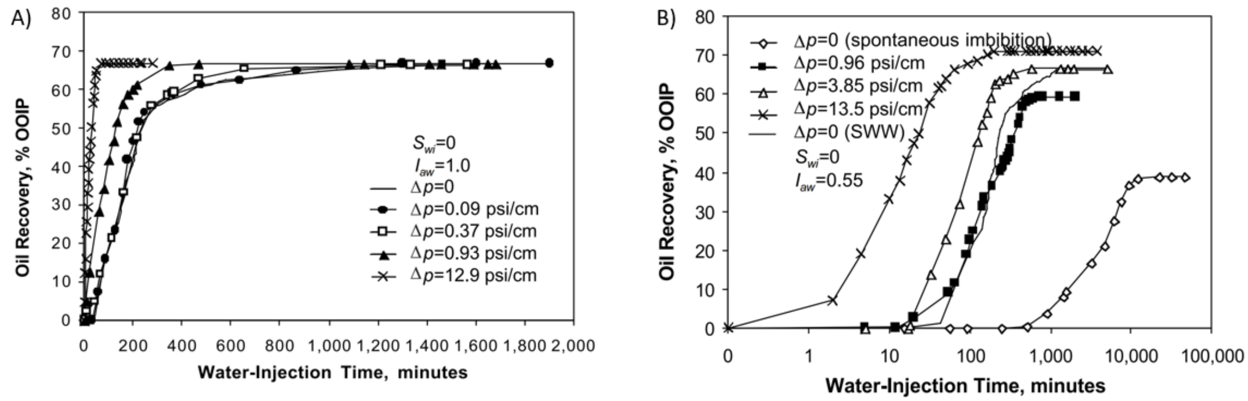

Figure 8- Effect of pressure gradient on oil recovery by water injection for a strongly water-wet rock (A), and a weakly water wet rock (B) (Tang and Firoozabadi 2001)

Chapter 3: Experimental Methods and Procedures

3.1. Materials

Berea sandstone cores with a diameter of 2.518 cm and a length of 14.7 cm were used for all flooding experiments. Isopar L™ (Corechem inc, Knoxville, TN) was used as a substitute for crude oil. The density was measured using a pycnometer and the viscosity measured using a cannon capillary viscometer. A 3 wt.% potassium chloride (KCl) (Sigma Aldrich, St Louis, MO) brine with a density of 1.0164 g/cc and a viscosity of 1 cP, was used for all saturation processes and flooding experiments. A 0.1 wt.% Polyacrylamide solution (Limefav) with a density of 1.0164 g/cc and a viscosity of 3.55 cP was used for the polymer injection, and a 0.5 wt.% Tergitol® solution (Union Carbide, Seadrift, TX) with a density of 1.0163 g/cc and a viscosity of 1 cP was used for the surfactant injections.

3.2. Experimental Setup and Procedures

3.2.1. Rock characterization

Fourteen Berea sandstone cores were obtained from a block by using a 1-inch coring bit and are shown on **Figure 9**. The cores were then placed in the oven for drying overnight at a temperature of 140°C, and characterized by measuring their weight, diameter and length, porosity, and permeability.

Figure 9- Berea Sandstones cores

Porosity measurement protocol: The porosity of the samples was measured using the setup shown on **Figure 10** and by flowing the below protocol:

- After verifying that all valves are open, the sample is loaded into the cell using the appropriate spacers, ensuring that they are loaded into the cell before the sample.
- The cell is then connected to the system and secured using a clamp to avoid damaging it.
- After confirming that the pressure reading is zero, the system is then pressurized to approximately 100 pisg after closing sample valve and the vent. Once pressurized, the system valve is closed, and the system is checked for any leak.
- Next, after recording the pressure reading for P_1, the sample valve is opened and the pressure change is to be observed for a few seconds until the system stabilizes, and the reading for P_2 is recorded.

- To disassemble, the vent valve opened, and the system valve opened before carefully removing the sample cell, ensuring the top part remains stationary.

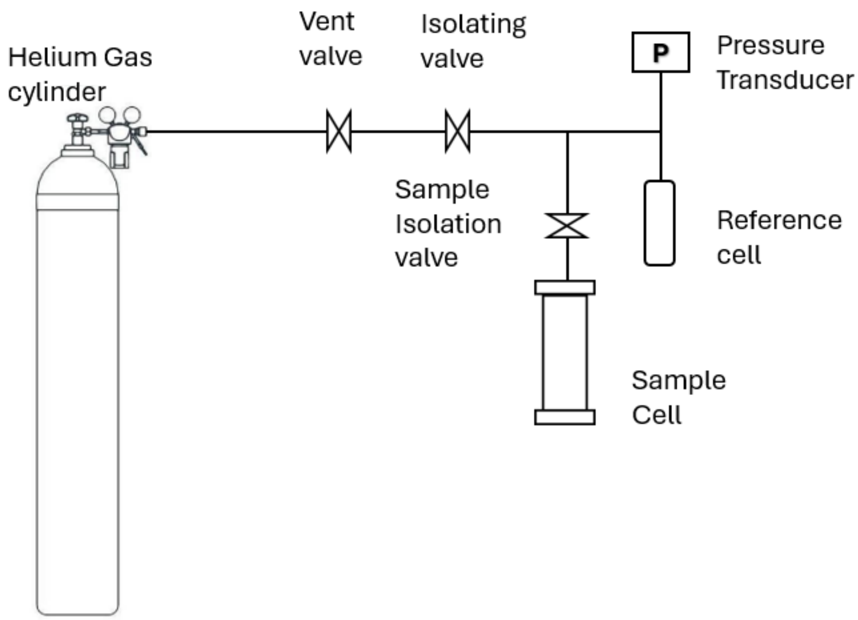

Figure 10 Porosity measurement setup

The porosity is calculated by using the Boyle's law equation set up in an excel sheet with a calibration done to account for the spacers' volumes and any dead volume.

$$P_1 V_1 = P_2 V_2 \tag{3}$$

Gas permeability measurement protocol: The gas permeability of the samples was obtained with the setup shown on **Figure 11** and by using the following protocol:

- First ensure the core holder and system are thoroughly dried before assembly.
- Confirm the necessary spacers based on the core length, then place the spacers inside the core holder before adding the rock, paying attention to the rock's inlet and outlet.
- Attach the movable end cap, connect the overburden pump and build the pressure to 1200 psi, then check for any leaks by monitoring for a drop in pressure.

- Attach the inlet transducer and inlet gas injection tubing and ensure the pressure transducers read zero. Note the pressure in the cylinder and keep track of it, along with the lab's ambient temperature and pressure if available.
- When measuring permeability, apply a gas pressure of 100 psi at the inlet and pressure at the outlet to achieve approximately 65 psi.
- Record P_1 and P_2 that are respectively the inlet and outlet pressures and measure the gas rate by opening the vacuum, allowing water to rise to V_1, inserting the air tube into a graduated cylinder, and using a stopwatch to measure time t. Note V_2 at the end of the run.
- Increase the back pressure by 5 to 7 psi and repeat the readings until at least three readings are collected at very low rates with a minimal pressure difference, with smaller pressure increments towards the end.
- For disassembly, close cylinder valve, release the cylinder pressure, and open the back pressure while holding the plastic tube for safety. Release the overburden pressure, disconnect the inlet transducer and inlet tubing while ensuring the fitting remains connected, and remove the inlet end cap and rock. Finally, inspect the rock for any liquid.

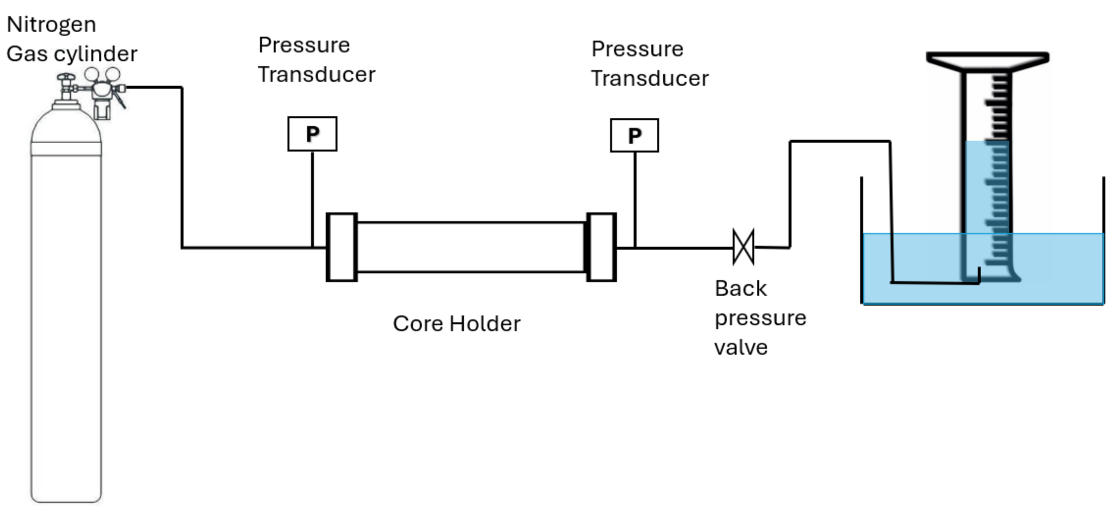

Figure 11- Permeability measurement setup

3.2.2. EOR experiments

3.2.2.1. Sample Preparation

The rock preparation process begins with confirming the latest dimensions, dry weight, porosity, and permeability of the rock and then saturated with a 3 wt% KCl brine. During the vacuum saturation with brine, the cooler is turned on for an hour and thirty minutes while ensuring the saturation cell is clean. The rock is then weighed, placed horizontally in the cell that is plugged with a stopper. Vacuum grease is then applied to the edges to ensure that there are no leaks. Enough fluid is prepared to cover the sample by at least 1 cm, and the fluid injection tube is placed in the fluid container. After the cooler runs for an hour and thirty minutes, both vacuum valves are confirmed open, the fluid valve is closed, and the vacuum is turned on. After a few minutes, the vacuum is turned off, vacuum valve #2 placed between the desiccator and the gauge (as shown on **Figure 12**) is closed, and the fluid valve is slowly opened for a fraction of a second to lift water into the tube, then quickly closed. Vacuum valve #2 is reopened, and the vacuum is turned on for about one hour. Afterward, vacuum valve #2 is closed, and the fluid valve is opened to let the fluid in while the vacuum pump is turned off. The tube must be at the bottom of the fluid container to ensure all the fluid flows into the desiccator. Once the rock is covered with fluid and air enters the system reaching atmospheric pressure, vacuum valve #2 is opened, resulting in a brief air flow. The cooler is turned off, and the rock sits in the fluid for 15 to 30 minutes. The rock is then removed from the fluid, excess fluid is wiped off with non-absorbent material (such as gloves), and the rock is quickly weighed before being placed back in the brine. Saturation calculations are performed immediately, comparing the volume of water to the pore volume from porosity measurements.

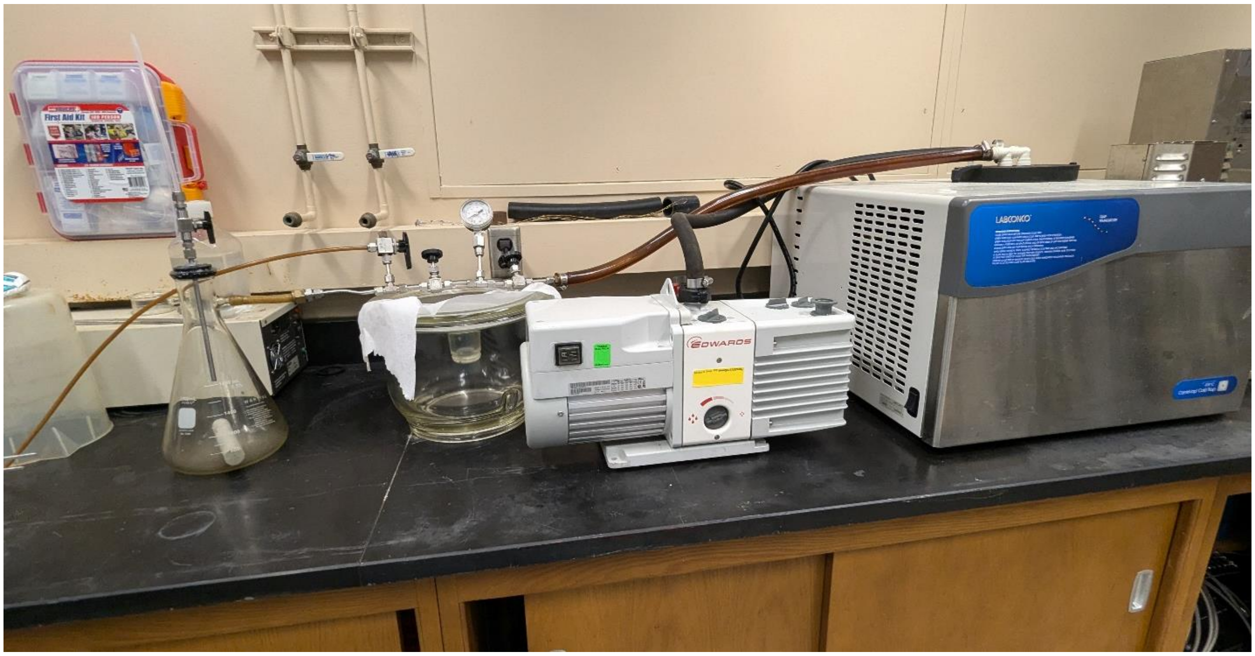

Figure 12- Rock saturation set-up

3.2.2.2. Core flooding experiments

The core flooding experiments were performed using two methods, constant rate injection and constant pressure injection. The experiments were performed using a Teledyne Model 500D Syringe pump connected to an accumulator containing the fluids to be injected, which is connected to the core holder. The set up is presented on **Figure 13**.

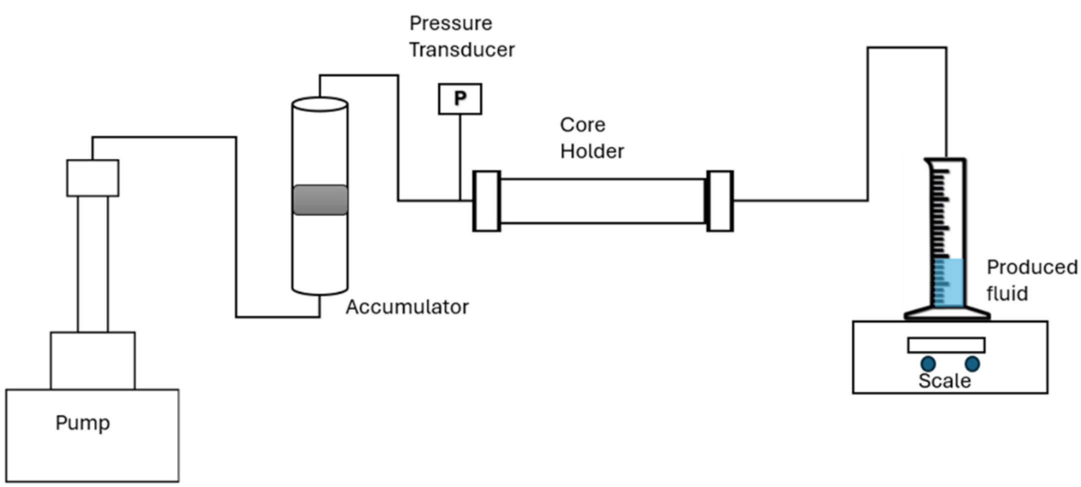

Figure 13 Core flooding experiment setup

The first brine injection was done by injecting 3 wt% KCl brine at a constant rate of 2cc/min for 3 pore volumes (PV), followed by an Isopar L injection at a rate of 0.5 cc/min for 5 to 6 pore volumes with the water produced noted. No aging was done for this study. For the constant rate method, waterflooding and surfactant flooding were done at different rates that are 1cc/min, 0.02 cc/ min. the polymer flooding was done at a 0.5 cc/min due to equipment pressure limitations. For the constant pressure injection method flooding experiments were conducted at a high pressure of 150 psi and a low pressure of 10 psi.

Chapter 4: Experimental results and discussions

4.1. Fluid and rock Properties

To conduct core flooding experiments, it is important to measure rock properties as they influence the results. Porosity and permeability measurements done on all Berea cores are presented in **Table 2** along with initial water saturation data:

Table 2- Porosity and permeability results

Core	Length (cm)	Diameter (cm)	Weight (g)	Porosity %	K (mD)	Initial Sw (%)
TB13	14.7	2.518	155.89	20.32	125.96	96.71
TB21	14.7	2.518	155.82	20.36	120.03	95.59
TB19	14.7	2.518	155.43	20.45	126.11	96.90
TB13, 2nd	14.7	2.518	155.82	20.83	125.96	95.33
TB20	14.7	2.518	155.65	20.41	121.52	97.79
TB18	14.7	2.518	155.35	20.58	126.02	95.69
TB22	14.7	2.518	155.26	20.59	122.61	95.45
TB17	14.7	2.518	155.27	20.66	123.06	95.59
TB11	14.7	2.518	155.02	20.81	123.81	94.67
TB14	14.7	2.518	156.12	20.17	124.10	97.68
TB15	14.7	2.518	156.08	20.24	119.79	95.56
TB24	14.7	2.518	155.27	20.67	126.87	96.50
TB16	14.7	2.518	156.1	20.19	118.94	97.08
TB9	14.7	2.518	154.35	21.17	128.17	94.17

The cores had an average porosity of 20.31% ±0.46% and an average permeability of 123.55mD ± 3.15 mD which are within the range of reported values in the literature (Al Nuaimi 2014, Churcher et al. 1991, Gray and Fatt 1963).

As discussed earlier, oil mobilization is highly influenced by the capillary number which is the ratio of viscous forces to capillary forces (Fulcher Jr et al). Viscous forces are the fluid velocity and viscosity, and the capillary forces are dominated by the interfacial tension and pore geometry. Viscosity, surface tension, and interfacial tension measurements were made for the different fluids used for the flooding experiments and are presented in **Table 3** below. IFT measurements images are presented in **Appendix A**.

Table 3- Fluid properties

Fluid	Density (g/cc)	Viscosity (cP)	S. Tension (dyne/cm)	IFT (dyne/cm)
Water	0.9968	1	70.25	
Oil (Isopar L)	0.7601	1.7	22.27	27.31
3wt.% KCl brine	1.0164	1	71.01	
0.5wt.% Tergitol in 3% KCl	1.0163	1	29.28	2.05
0.1wt.% pol in 3% KCl	1.0164	3.55	70.97	45.12

4.2. Core Flooding Experiments Parameters Selection

Before conducting core flooding experiments, injection pressures and rates were selected to match pressure gradients that can be observed in the field. This was done by calculating the pressure gradients for our sample using Darcy's law equation for radial flow (Equation 4) to match pressure gradients that are typically seen in the field near both injection and production wells. For the case of a production well, the equation would be:

$$P_e - P_{wf} = 141.2 \frac{q\mu ln\frac{r_e}{r_w}}{kh} \quad (4)$$

Where Pe is the effective pressure or reservoir pressure, P_{wf}, the inflow pressure, q the flowrate, r_e, the effective radius, r_w the well radius, μ the viscosity, k, the permeability, and h the thickness of the reservoir.

The logarithmic relationship between the pressure and the radius results in high pressure gradients near the wellbore and lower gradients away from the wellbore. As we move away from the well, the pressure gradient decreases which impacts flow through the reservoir. For a production well in a reservoir with the parameters shown in **Table 4** below, pressure gradients observed can range from 4.3 * 10^{-3} psi/cm to 7.1 psi/cm, with the latter being the gradient close to the well. The pressure gradient 100 ft from the well in this case is equivalent to an injection pressure of 10 psig in the laboratory setting. An even lower injection pressure would be needed to match the gradient expected further away from the well. Hence, conducting experiments that result in higher pressure gradients might be misleading.

For this study an injection pressure of 10 psi and 150 psi were selected to show the pressure effect and to show how using relevant injection pressure can affect the results obtained.

Table 4- Hypothetical reservoir parameters

Q	2000	bbl/day
B	2	res bbl/STB
visc	1	cP
k	120	mD
h	30	ft
re	1200	ft
rw	0.3	ft
Pe	5000	psi
Pwf	3698.76	psi

Injection rates for this were also selected going from pressure gradient that can be observed and a flow rate of 0.02 cc/min and 1 cc/min were selected. As mentioned in the literature review part, several studies done using the constant rate injection method do not take into consideration the effects of the variable pressure gradient conditions.

4.3. Constant Rate Injection

The constant rate injection experiments were conducted in three stages, after vacuum-saturating the rock using brine, where the stages included brine injection, followed by an oil injection, and finally another fluid injection that could be brine, surfactant, and polymer. The data collected during the experiment were the pressure, weight, and volume of fluid collected. **Figures 14** to **Figure 16** Show the pressure response as a function number of pore volumes of fluid injected for one core sample.

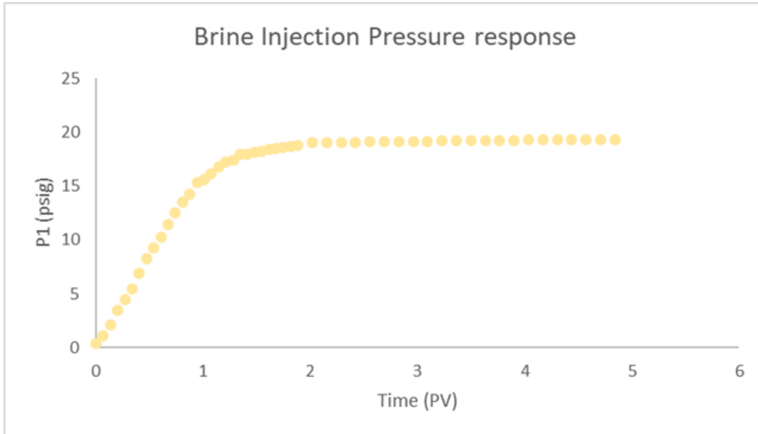

Figure 14-Brine injection Pressure response

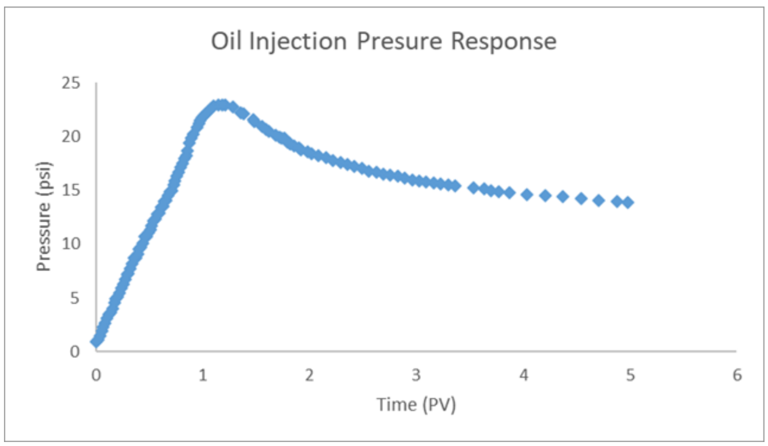

Figure 15-Oil injection Pressure response

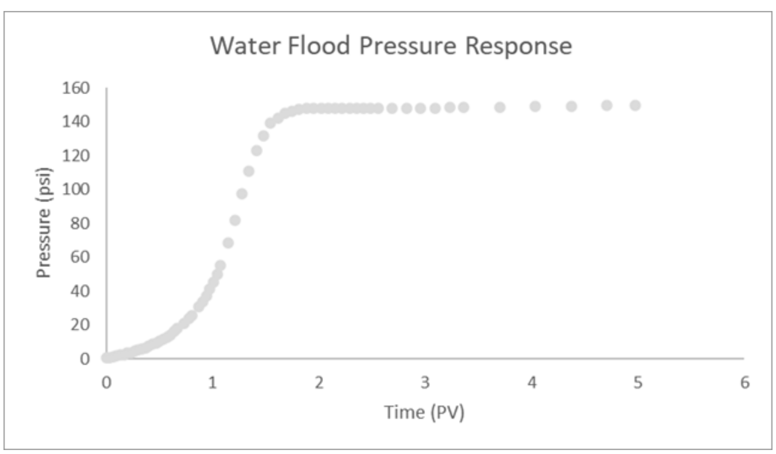

Figure 16- Waterflood Pressure response

Different procedures were explored before selecting the last one that we used. In the first method, the rock was removed after each injection to measure the weight, the second method was to remove the rock after the oil injection to record the weight of the rock, but these methods led to a lot of air being introduced into the system resulting in low confidence in the calculated recovery. The final method was to not remove the rock until the end of the experiment and record the final weight to calculate the final Sor. The results of the water flooding experiments at flowrates of 1 cc/min, 0.07 cc/min, and 0.02 cc/min are presented in **Table 5**. It can be seen that the higher flow rate yields lower Sor, but also has higher pressure readings during the experiment.

Table 5- Constant Rate injection result summary

Core	Method	q (cc/min)	P (psi)	Kw (mD)	Ko (mD)	Kew (mD)	Sor (%)
TB20	Core sample not removed duirng flooding experiment, Sor calculated using produced volume	0.02	4.7	70.91	43.91	3.077	48.9%
TB21	Core sample removed after each fluid injection, Sor calculated usinf final weight	0.07	13.1	77.35	46.93	3.865	40.6%
TB13	Core sample removed after each fluid injection, Sor calculated using produced volume	1	148	75.73	44.23	4.890	28.9%
TB19	Core sample removed after each oil injection and after secondary brine injection, Sor calculated using final weight	1	173.2	74.95	44.23	4.176	36.0%
TB13 (2)	Core sample cleaned and reused, not removed duirng flooding experiment, Sor calculated using final weight	1	244.7	52.6	32.02	2.955	37.6%

The method of constant rate injection leads to variability in pressure conditions between different experiments. When we compared the performance of brine versus surfactant injection at two of the rates, we noticed that some variability can be observed at the lower injection rate and less variability is seen at the higher rate, as shown in **Figure 17**.

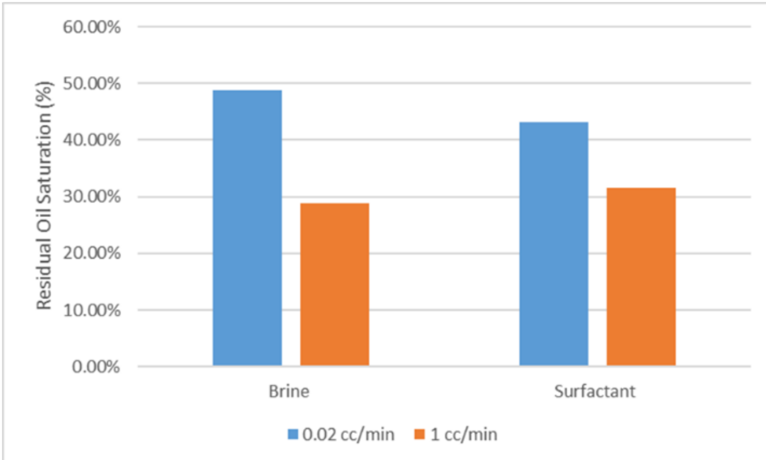

Figure 17- Residual oil saturation results for brine and surfactant injection at constant rates of 0.02 cc/min and 1 cc/min

4.4. Constant Pressure Injection

Constant Pressure injection experiments were conducted by first injecting the brine, then the oil at constant rate, followed by the third injection (mimicking EOR) at constant pressure. The pressures were selected after calculations were made to estimate the pressure gradient and selecting the one close to field condition for the low-pressure injection. Results for constant pressure flooding are summarized in **Table 6** and **Figure 18**.

Table 6- Constant Pressure Injection Result summary

Core	Method	EOR	Injection P (psi)	Kw (mD)	Ko (mD)	Kew (mD)	Sor (%)
TB11	3% KCl, not removed cst pressure	WF 3wt% KCl	50	53.57	39.66	2.88	37.69%
TB14	3% KCl, not removed cst pressure	WF 3wt% KCl	10	67.28	41.82	2.91	36.45%
TB15	3% KCl, not removed cst pressure	WF 3wt% KCl	150	45.20	37.95	5.13	34.53%
TB24	0.5%T, not removed cst pressure	Surfactant, 0.5 wt% Tergitol	10	68.55	44.87	2.56	36.08%
TB9	0.5%T, not removed cst pressure	Surfactant, 0.5 wt% Tergitol	150	40.63	42.99	10.64	24.58%
TB16	0.1%Poly, not removed cst pressure	Polymer, 0.1 wt% Polyacrylamide	10	32.80	36.16	0.32	46.04%
TB7	0.1%Poly, not removed cst pressure	Polymer, 0.1 wt% Polyacrylamide	150	28.70	33.59	0.49	43.89%

At 10 psi, using the surfactant did not significantly reduce the Sor (reduced to 36.08% from 36.45%), however at 150 psi, Sor was reduced from 34.53% to 24.58%. This shows that reducing IFT alone, in this system, is not enough for a significantly improved recovery and that the pressure effect should be taken into consideration. Performing the experiments for this system at a pressure gradient that is not equivalent to what is expected in the field will result in the wrong conclusions about whether or not an increase in recovery should be expected for this system. In this case, an additional almost 10% recovery could mistakenly be anticipated, as compared to around 0.5% enhancement. The relative permeability results also confirm the pressure effect with the results being higher at higher pressure (the surfactant having the highest relative permeability at 150 psi). These kinds of high pressures are not encountered in field conditions, and this means that many studies might have overestimated their results of enhanced oil recovery.

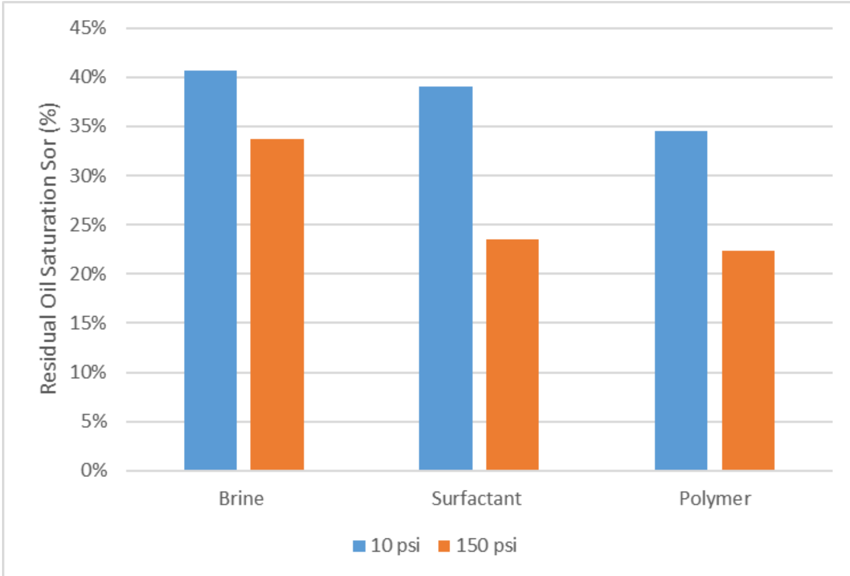

Figure 18- Residual oil saturation results for brine, surfactant, and polymer injection at constant pressures of 10 psi and 150 psi

In short, it can be seen from the results that a higher injection pressure and higher flow rates lead to lower residual oil saturation (Sor) which agree with the literature. However high injection rates and injection pressures might not be relevant to field conditions which leads to overestimation or misleading results. This tells us that these parameters need to be taken into consideration when studying the EOR method. Careful considerations need to be implemented when choosing the suitable laboratory conditions that are equivalent to the relevant field conditions, even if those experiments can be more tedious and more time consuming.

Chapter 5: Conclusions and Recommendations

In this study, the effect of flow rate, pressure, viscosity and IFT on EOR was investigated. Two methods of flooding experiments -constant rate and constant pressure--were also conducted. It was found that higher injection rates and pressures lead to lower residual oil saturations, hence higher recovery. This highlights the importance of taking field conditions into consideration while studying EOR methods. While performing tests using constant-rate injection is easier to monitor, many teams do not consider that constant-pressure injection is needed for the results to be relevant to the conditions in the field. And in many cases, the rates used during constant rate injection are too high compared to the relevant field conditions. The results from these tests can lead to over-estimating recovery rates from EOR methods that are examined, misleading conclusions on the optimization process for EOR, and misleading conclusions on the mechanisms that control the process of EOR.

While following a strict protocol in performing Enhanced Oil Recovery experiments takes more time, effort, and cost, it is an essential element towards reliable EOR conclusions. The most common mistakes in the literature include:

- Utilizing constant-rate as opposed to constant-pressure injection,
- Utilizing injection rates that are too high compared to conditions relevant to the field,
- Using reservoir rocks that are too short, resulting in significant capillary end effects,
- While utilizing surfactants and polymers reduces interfacial tension and that should result in additional recovery, the amount of enhanced recovery rate is over-estimated in most of the experimental studies.

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Appendix A: Interfacial Tension measurements (IFT) results

Surface tension and IFT measurements were made using Kruss Drop shape analyzer. Images captured during measurements are presented on Figure 14 and Figure 15 below.

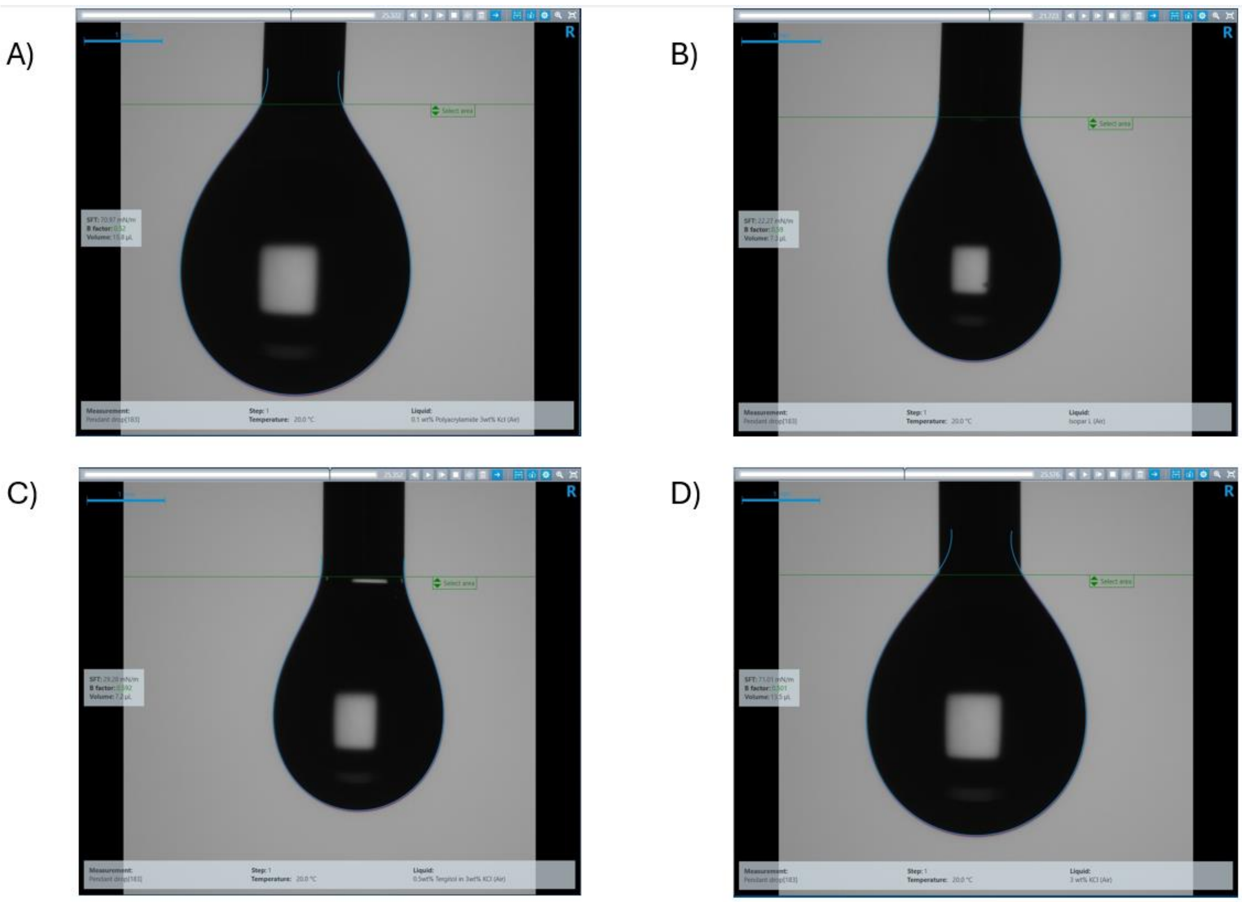

Figure 19- Surface tension results for 0.1 wt% Polyacrylamide (A), Isopar L (B), 0.5 wt% Tergitol (C), and 3 wt% KCl (D)

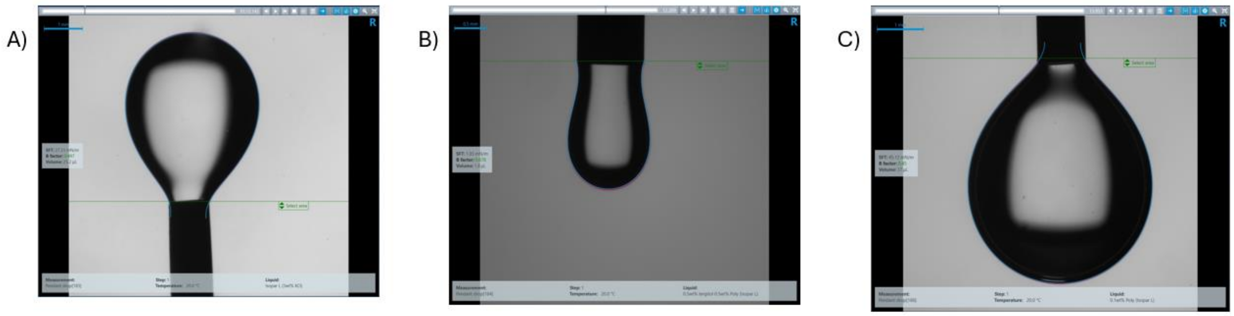

Figure 20- IFT results for Isopar L and 3 wt% KCl (A), 0.5 wt% Tergitol and Isopar L (B), and 0.1 wt% Polyacrylamide and Isopar L (C)