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**Article**

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# Smart Water Flooding for Enhanced Oil Recovery in Heterogeneous Carbonate Reservoirs: Experimental Evaluation of Engineered Brine Performance Under HPHT Conditions

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**Abstract**
Smart water flooding has become one of the efficient enhanced oil recovery (EOR) methods to enhance the output of oil in heterogeneous carbonate reservoirs. This paper is an experimental evaluation of engineered brine injection with the use of core samples in the WQ1-57 oilfield complex under conditions of high-pressure and high-temperature (HPHT) environments with an emphasis on the impact of $Ca^{2+}$, $Mg^{2+}$, and $SO_4^{2-}$ ions on wettability change, relative permeability, and the efficiency of oil displacement. Experiments on core flooding, monitoring pressure behavior, and analysis of effluent ions were done to measure the fluid-rock interactions. The findings indicate that smart water flooding substantially raises oil recovery of 31.7-50.4% OOIP under formation water flooding to 47.2-65.0% OOIP under smart brine injection, with an incremental recovery of about 20-30% OOIP. The relative permeability analysis revealed that water relative permeability and residual oil saturation decreased to 0.20-0.25, which was an indication of a transition towards more water-wet conditions. The behavior of pressure response showed the first growth then the stabilization, and it was characteristic of a gradual change in wettability and enhanced flow dynamics. $Ca^{2+}$, $Mg^{2+}$, and $SO_4^{2-}$ exchange was observed, which led to the expansion of the electrical double-layer and the oil-rock adhesion decrease. The research establishes that reservoir heterogeneity has a profound impact on recovery performance. Altogether, engineered brine design is a trustworthy and cost-effective EOR approach to carbonate reservoirs with a high probability to be applied at the field level.
**Keywords:** Smart water flooding; Enhanced oil recovery (EOR); Carbonate reservoirs; Wettability alteration; Engineered brine; Ion exchange mechanism.

## 1. Introduction

Carbonate oil field is considered to be one of the most significant oil assets in the world, with a significant portion of global oil production as a result of wide distribution and huge storage capacity [1]. These reservoirs are however usually characterized by a complex pore structure, high level of heterogeneity, natural fractures and mixed to oil-wet surface conditions, which highly inhibit the efficiency of traditional waterflooding operations and results in large amounts of residual trapped oil [2, 3].

During the last decades, the development of enhanced oil recovery (EOR) methods has been conducted widely in order to increase the efficiency of displacement in such problematic formations [4]. These techniques are chemical flooding, polymer injection and low-salinity waterflooding, which are extensively studied [5-7]. However, these methods are usually characterized by high chemical cost, limitations of operation, risks of formation damage, and lack of predictability of applicability at the field scale [8].

In recent years, smart water flooding (also known as engineered or ion-tuned water injection) has become a promising cost-effective and less damaging, and ecologically safer method of EOR in carbonate reservoirs [9]. The core concept of smart water flooding is that the composition of injected brine, and especially the concentration of the potential determining ions, including $Ca^{2+}$, $Mg^{2+}$, and $SO_4^{2-}$, is manipulated to change the surface chemistry of rocks and enhance their

recovery of oil [10, 11]. According to many experimental investigations, these ions are important in altering surface charge, broadening the electrical double layer and reducing forces of adhesion between oil constituents and carbonate surfaces finally resulting in a wettability transformation happen between an oil-wet and a more water-wet condition [12-14].

The current literature always points out that wettability modification is the most predominant mechanism that regulates enhanced oil recovery in the carbonate systems. It is common knowledge that ion exchange reactions, surface complexation, as well as expansion on a double-layer, are some of the important physicochemical reactions that transform the interaction between rocks and fluids and increase multiphase flow behavior [15]. Specifically, it has been demonstrated that the synergy between the sulfate ions and divalent cations ($Ca^{2+}$ and $Mg^{2+}$) can greatly enhance oil recovery, destabilizing the oil rock adhesion and creating water-wet oil conditions in carbonate formations [16].

Experimental studies also show that low-salinity and smart water injection has the potential to boost oil recovery by a large margin in comparison to the traditional waterflooding [17]. Incremental recovery additions have been reported to be between 10 and 30 percent of initial oil in place (OOIP), depending on the rock mineralogy, initial wettability, and brine composition, and reservoir temperature conditions. These enhancements are highly affected by the preliminary wettability condition of carbonate rocks that determine the capillary pressure, relative permeability conduct and fluid dispersion within the pore system [18].

Besides wettability change, the significance of interfacial tension decrease and micro-scale redistribution of fluids as secondary processes that lead to the increase in displacement efficiency has also been highlighted in recent literature [13, 20]. The reaction between the brine chemistry and the crude oil constituents, especially the polar organic acids, also favor the development of better flow conditions and enhanced sweep efficiency. It has also been shown through advanced modeling and experiments that by optimizing ion ratios (in particular $Mg^{2+}/SO_4^{2-}$ and $Ca^{2+}/SO_4^{2-}$), the performance of smart water flooding may be improved by a significant margin through the control of surface charge behavior and reduction of the adhesion forces on the oil [21].

These developments notwithstanding, the performance of smart water flooding is extremely sensitive to reservoir-specific factors, such as heterogeneity of permeability, mineral composition, temperature, and crude oil properties. Hence, laboratory studies are needed in greater detail to comprehend the combined effects of rock-fluid-brine interactions in realistic reservoir conditions.

Here, the current research examines the influence of engineered smart brines on carbonate core samples in high-pressure, high-temperature core flooding tests. The study aims at assessing the change of wettability, relative permeability characteristics, and incremental recovery of oil under varying injection conditions. The results will be used to gain a more in-depth insight into the controlling processes of the smart water flooding, as well as serve to add to the optimization of the enhanced oil recovery methods in heterogeneous carbonate reservoirs.

## 2. Study Area Description

The research relies on core sampling and reservoir data retrieved at the WQ1-57 oilfield complex that can be regarded as the representative case study of the carbonate reservoirs systems. The reservoir is found in the sedimentary basin setting with large hydrocarbon containing carbonate formations, much akin to numerous fields in the Middle East and other arid to semi-arid petroleum provisioning [22].

Geographically, the region falls in large low-relief sedimentary plains, whereby flat terrain and dense stratified geology prevails both on the surface and underground. These environments are

common with large carbonate reservoirs developed in stable depositional conditions and subsequently changed by diagenetic and structural factors.
The climate category of the area is semi-arid to arid, with hot temperatures, minimal rainfall per year, and strong seasonal changes. Even though such climatic conditions only influence the operations on the surface, they are also involved in the management of water resources, as well as in the introduction of improved oil recovery plans.
The WQ1-57 reservoir is geologically made up of heterogeneous carbonate formation with an intricate pore structure, variable permeability, and mixed wettability environment. The cause of these heterogeneities is primarily depositional facies variation, diagenetic variation, and fractures, each of which has a marked effect on the behavior of fluid flow and recovery efficiency.
Thus, although the case study of the experiment is WQ1-57, the results of this study can be generalized on the application to analogous carbonate reservoir systems in the world and specifically those that are intended to be utilized in the exploitation of oil with the application of smart waterflooding methods.

## 3. Materials and Methods

The experimental program will, in this chapter, be presented to determine the effects of the smart water composition on the relative permeability, change of wettability and oil recovery of the carbonate reservoir cores of the WQ1-57 oil well complex in the oilfield. To simulate the reservoir conditions, the laboratory tests were done and critically needed to offer a scientific foundation to examine the impact of the ionic composition of injected brine on multiphase flow behaviors and displacement effectiveness in the carbonate formations.

### 3.1 Experimental Program Design

To measure the performance of smart waterflooding in the controlled laboratory conditions that are closely related to the WQ1-57 reservoir, the experimental program was planned systematically. It combined detailed studies of property of rocks, fluids and brines to examine the impact of ionic compositions, salinity and temperature on multiphase flow conditions, wettability change, and oil recovery efficiency in carbonate formations.
The methodology was a series of organized steps (as shown in Figure 1), which started with preparation and characterization of core samples to recreate conditions in-situ reservoirs. This was succeeded by thorough chemical and physical examination of formation water and designed brines with special concentration on major ions like $Ca^{2+}$, $Mg^{2+}$, and $SO_4^{2-}$ to assure compatibility and reduce chances of scaling. This was followed by conducting core analysis and relative permeability tests to determine the characteristics of fluid flow at different levels of saturation. Afterwards, core-flooding experiments were conducted under high pressure and high temperature to mimic the behavior of the reservoir and conduct an analysis of the efficiency of oil displacement with changes in wettability caused by smart brine injection.

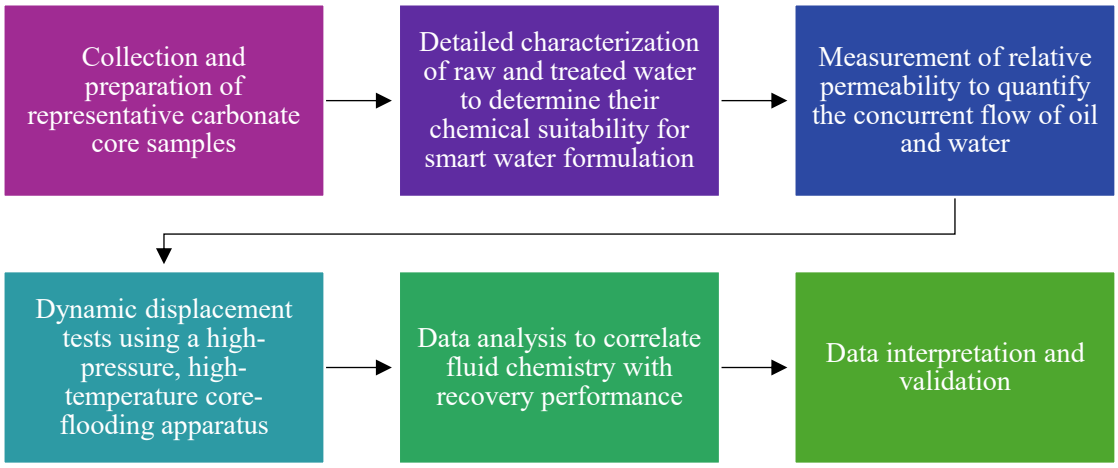


Figure 1. Experimental workflow for smart waterflooding evaluation.

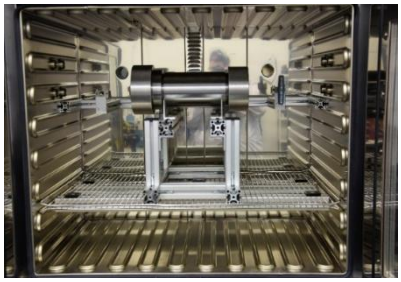
### 3.2 Materials and Equipment

Core samples and reservoir fluids taken at the WQ1-57 oil field were used in the study and it used sophisticated laboratory tools to recreate the conditions of a real reservoir.

Four horizontal wells WQ1-57 (5H), (43H), (44H), and (76H) representing different parts of the same interval of reservoir were sampled with carbonate core. The samples were cleaned, dried, and ready to test, and significant petrophysical parameters such as porosity, permeability, and the pore volume were determined. The cores had porosity of about 26-30% and permeability of 17-1020 mD, which was moderate to high permeability characteristic of carbonate formations. These properties were vital in the establishment of the right conditions of experimental flows.

The test fluids were crude oil, formation water, and smart smartly engineered brines. The crude oil was kept in its natural form in order to retain its natural properties whereas formation water was studied to create a baseline composition. The concentrations of $Ca^{2+}$, $Mg^{2+}$, and $SO_4^{2-}$ were then adjusted to achieve smart brines that would facilitate wettability change, and the salinity and chemical composition were confirmed by laboratory studies.

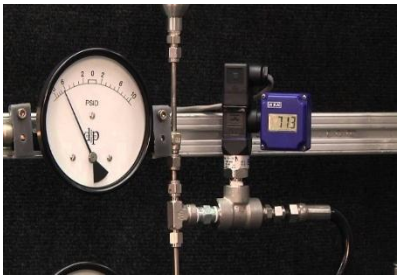
The experiments consisted of flooding with a high-pressure and high-temperature (HPHT) core-flooding system that was developed to simulate the conditions in a reservoir. The system (shown in Figure 2) comprised an all-metallic core holder that could withstand high pressure and temperature, two injection pumps that could be controlled to inject a fluid at a specific rate, a back-pressure regulator that ensured the outlet pressure remained constant, a pressure monitoring system that would monitor the real-time measurements, an oven with controlled temperature and pressure, and effluent collection units to analyze the produced fluids.



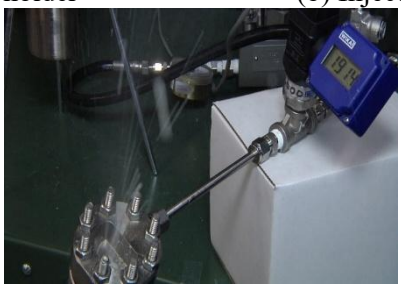
(a) Core holder



(b) Injection pumps



(c) Back-pressure regulator.



(d) Pressure monitoring system.



(e) Temperature-controlled oven.

Figure 2. Experimental setup of core flooding apparatus.

A set of advanced analytical instruments was employed to characterize both rock and fluid properties with high precision, as listed in Table (1). These instruments ensured the accuracy, reliability, and reproducibility of all experimental measurements, providing a robust quantitative basis for evaluating the performance of smart waterflooding in the tested carbonate cores.

Table 1. Analytical instruments used for rock and fluid characterization.

| Instrument | Purpose / Description |
|---|---|
| pH Meter | Measures the acidity or alkalinity of raw and treated water samples. |
| Conductivity Meter | Determines electrical conductivity and estimates total dissolved solids (TDS) in water samples. |
| Spectrophotometer | Detect sulfate, chloride, and other ionic species in brine samples. |
| Ion Chromatography System | Provides accurate quantification of key potential determining ions such as $Ca^{2+}$, $Mg^{2+}$, and $SO_4^{2-}$. |
| Viscometer and Densitometer | Measure crude oil viscosity and density under reservoir temperature conditions. |
| Core Analyzer | Determines porosity and permeability of rock samples using helium porosimeter and steady-state flow methods. |

### 3.3 Chemical and Physical Characterization of Water Samples

The physical and chemical characterization of water is the key to designing smart brine to be used in flooding experiments. The step guarantees mixability of injected water, carbonate rock, and crude oil hence reducing the chances of scaling, precipitation, and formation damage. It also gives baseline data to modify ionic composition to realize effective wettability modification.

Oilfield treatment facilities were sampled with water and analyzed based on ASTM and APHA standards to guarantee accuracy and reproducibility. Two samples were taken into consideration: untreated (raw) water and injectable treated water. The main parameters that were measured were pH, temperature, alum dosage, chloride, alkalinity, electrical conductivity (EC), total dissolved solids (TDS), total suspended solids (TSS) and turbidity. These parameters are essential in the

evaluation of the water quality, salinity, ionic strength and likelihood of scaling or pore blockage. The outcomes were employed to confirm that treated water was fit to prepare smart brine under the requirements and safe injection under the conditions of the reservoir. Key physicochemical characteristics and the corresponding tests are provided in Table (2).

Table 2. Chemical and physical properties of raw and treated water samples.

| Parameter | Unit | Test Method / Standard |
|---|---|---|
| pH | - | ASTM D1293 |
| Temperature | °C | ASTM D5463 |
| Alum Dosage | mg/L | APHA 2340 |
| Chloride ($Cl^-$) | mg/L | APHA 4500-$Cl^-$ |
| Alkalinity (as $CaCO_3$) | mg/L | APHA 2320 |
| Electrical Conductivity (EC) | µS/cm | ASTM D1125 |
| Total Dissolved Solids (TDS) | mg/L | Gravimetric Method |
| Total Suspended Solids (TSS) | mg/L | APHA 2540 D |
| Turbidity | NTU | APHA 2130 B |

### 3.4 Core Analysis and Rock Characterization

A detailed core analysis and rock characterization were carried out to ascertain the petrophysical and flow properties of the carbonate cores of the WQ1-57 oilfield as a source of input data to be used in the later flooding and relative permeability experiments. The core samples were taken in several horizontal wells WQ1-57 (5H), (43H), (44H) and (76H), prepared with care, labeled, dried and stored to maintain the integrity and provide reliable testing.

Standard laboratory methods were used to measure the key petrophysical properties such as porosity, absolute permeability and pore volume. A helium porosimeter was used to measure porosity, and a steady-state gas permeameter was used to measure permeability. The properties were important in the selection of representative samples and establishment of suitable experimental conditions.

Besides the static properties, dynamic flow behavior was also tested by means of relative permeability. The relative permeability of water versus oil (Krw, Kro), saturation of water (Sw), oil recovery, water cut, and phase flow fraction (Fo and Fw) parameters were measured to evaluate the properties of fluid displacement, wettability, and residual saturation of the oil with water.

The general laboratory procedure of the dynamic flow analysis is described in Figure (3), which is a summary of the ordered steps that are undertaken in the process of testing.

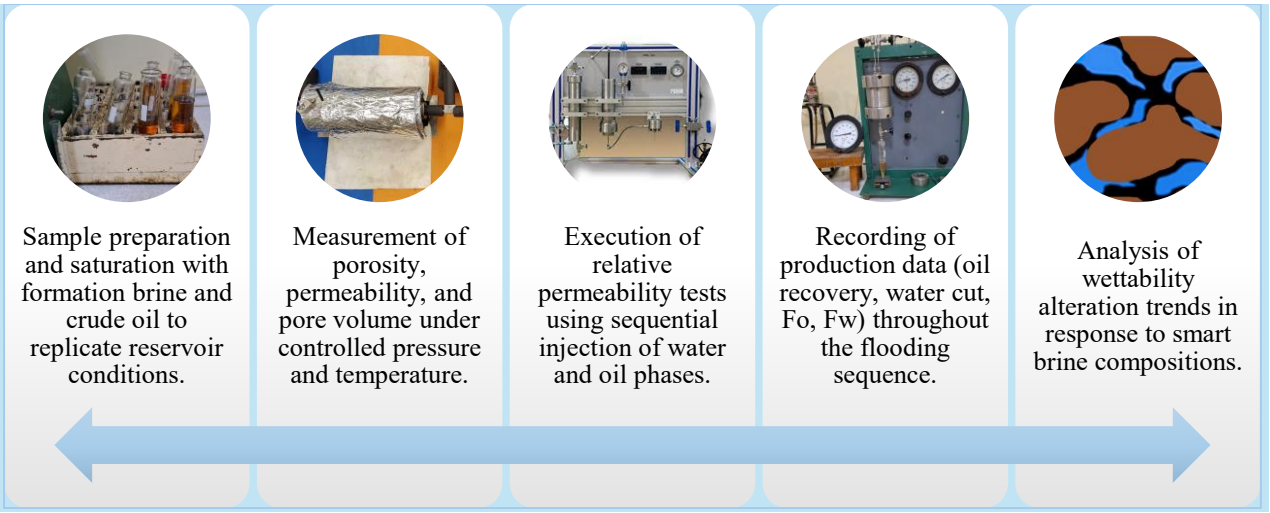



Figure 3. Laboratory workflow tests of dynamic flow properties.

The basic analysis techniques were performed in line with API RP 40, ASTM D4525 and ISO 13535 guidelines to ensure reliability and repeatability of data. Table (3) provides the most important parameters that were obtained in every core that was tested and this can be used to construct a frame of the experiment to be conducted later.

Table 3. Core analysis and flow parameters for WQ1-57 well.

| Parameter | Unit | Test Method / Standard |
|---|---|---|
| Well Number | - | Field Identification Record |
| Depth | M | API RP 40 - Core Handling and Logging |
| Formation | - | Geological Description and Logging |
| Sample Number | - | Laboratory Core Identification System |
| Porosity (Φ) | % | ASTM D4404 - Helium Porosimeter Method |
| Absolute Permeability (Ka) | mD | ASTM D4525 - Gas Permeameter / Steady-State Method |
| Pore Volume (Vp) | cc | Calculated from Porosity and Bulk Volume |
| Relative Permeability to Water (Krw) | - | ASTM D6836 - Steady-State Relative Permeability Test |
| Relative Permeability to Oil (Kro) | - | ASTM D6836 - Steady-State Relative Permeability Test |
| Water Saturation (Sw) | % | API RP 40 - Core Saturation Analysis |
| Oil Recovery | % | API RP 63 - Evaluation of Recovery Factor during Core flooding |
| Water Cut | % | ASTM D4007 - Water and Sediment in Produced Fluids |
| Fraction of Oil in Flow (Fo) | - | Derived from Flow Rate and Phase Fraction Calculations |
| Fraction of Water in Flow (Fw) | - | Derived from Flow Rate and Phase Fraction Calculations |

### 3.5 Core Flooding Experiments

The experiments with core flooding were carried out under the conditions of high pressure, high temperature (HPHT) to model the behaviour of multiphase fluid flow that represents carbonate reservoirs. The main aim was to determine the impact of various injection brines, formation water, treated water, and smart brine on the efficiency of oil displacement, change in wettability, and

pressure behavior. The main parameters that were established included the initial water saturation (Swi), residual oil saturation (Sor), and incremental oil recovery.
Ready samples of carbonate cores were loaded into a stainless steel core holder that was to endure the conditions in the reservoir and attached to injection pumps, pressure transducers, a back-pressure regulator, and effluent collection systems. There was a confining pressure at least 500 psi greater than injection pressure to eliminate bypass flow, and temperature was regulated with a set of internal thermocouples to maintain stable experimental conditions.
The flooding process was conducted in three major phases as shown in Figure (4) which shows the order of the core flooding process.

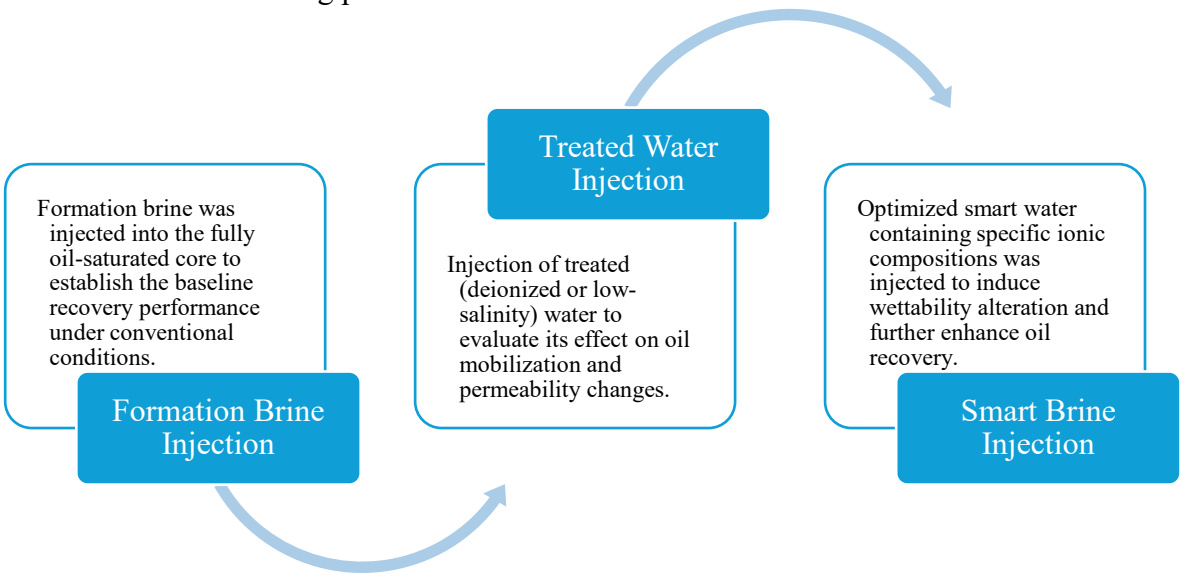



Figure 4. Flooding main stages sequence.

The main parameters such as injection rate, pressure drop ($\Delta P$) across the core and temperature were continuously recorded during the flood experiments. Periodic collection of effluent samples was done to measure produced volumes of oil and water and to determine the change in ionic composition due to ion exchange reactions between injected brine and the carbonate rock. Gravimetric separation was employed to determine oil recovery and water-cut whereas pressure profiles were employed to assess the change in flow resistance related to wettability change or fines migration.
Material balance calculations were used to ascertain initial water saturation (Swi) following oil saturation and residual oil saturation (Sor) following complete waterflooding. These parameters were applied to determine the performance of various injection brines, as well as to measure incremental oil recovery realized by smart water composition and optimization of injection strategies.
The general schematic arrangement of the experimental apparatus, comprising the core holder, injection apparatus, pressure regulators, and effluent collection units is shown schematically in Figure (5).

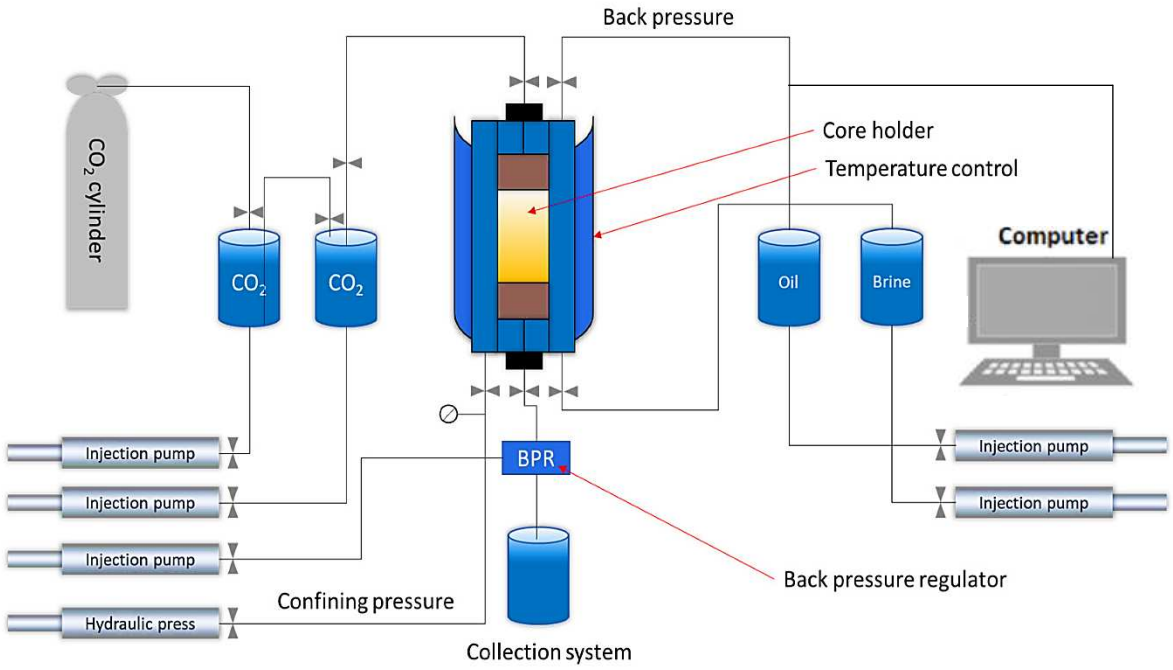



Figure 5. Schematic diagram of core-flooding setup.

### 3.6 Oil Flooding Tests

Oil flooding experiments were performed in order to determine the behavior of carbonate cores under a base line displacement before smart water injection and to establish the irreducible water saturation (Swi). These experiments were used to model initial reservoir conditions and gave a benchmark to assess incremental oil recovery obtained by smart waterflooding.

The WQ1-57 wells (5H, 43H, 44H, and 76H) were first saturated with formation brine (100 percent water saturation), and then the crude oil injection was continued under constant flow rate and reservoir temperature up to no further water production was recorded, which is the Swi. The injection rate, pressure difference ($\Delta P$), and volumes of fluids were kept under a constant check during the flooding process, and the effluent samples were sampled to calculate the oil and water cuts and the overall recovery performance.

The smart water injection was conducted under the same conditions after the oil flooding to be able to directly compare it with the conventional brine flooding. The resulting incremental recovery of oil was seen to be caused by the effects of ionic modification and wettability. The experimental protocol used API RP 63 and ASTM D6836 standards to provide consistency and reproducibility at HPHT conditions.

The important experimental parameters of the oil flooding stage are presented in Table (4) that determines the operating conditions and method of measurements during the tests.

Table 4. Summary of oil flooding experimental conditions

| Parameter | Unit | Test Method / Standard |
|---|---|---|
| Crude Oil Type | - | Field Sample - WQ1-57 Well |
| Oil Viscosity | cP | ASTM D445 - Kinematic Viscosity Test |
| Injection Rate | $cm^3/min$ | API RP 63 - Core Flooding Procedure |
| Injection Pressure | psi | Digital Pressure Transducer |
| Confining Pressure | psi | Hydraulic Confinement System |
| Temperature | °C | PID-Controlled Heating System |
| Initial Water Saturation (Swi) | % PV | Material Balance Method |
| Residual Water Saturation (Srw) | % PV | Calculated after Oil Flooding |
| Differential Pressure (ΔP) | Psi | High-Precision Pressure Sensor |
| Water Cut | % | ASTM D4007 - Water and Sediment Analysis |
| Oil Cut | % | Volumetric Measurement |
| Duration of Flooding | hr. | Experimental Log Record |

The results from the oil flooding stage serve as a fundamental baseline for evaluating smart water injection performance. They provide a quantitative framework for analyzing the effects of ionic composition on wettability alteration, pressure behavior, and incremental oil recovery in carbonate cores by comparing conventional and smart brine flooding responses.

## 4. Results and Discussion

### 4.1 Core Flooding Results and Performance Evaluation

The main aim of the core flooding experiments that were undertaken on the WQ1-57 carbonate cores was to assess the effects of brine composition on the behavior of multiphase flow and the performance of oil recovery. The experiments were conducted one after another with the formation water, treated water, and smart brine to remove the influence of engineered ionic composition on the efficiency of the oil displacement. The main parameters of measurements were the differential pressure (ΔP), fractional flow of water (Fw) and oil (Fo), the water cut, and the cumulative recovery of oil under conditions of reservoir simulation of temperature and confining pressure.

The introduction of intelligent brine caused a clear deviation in the pressure response, which was firstly an increase in the difference in pressure (ΔP) and then a stabilization and a decrease thereafter. This is a sign of the beginning of wettability change and the decrease in interfacial tension. Stabilization behavior of ΔP was dependent on permeability with low-permeability core WQ1-57 (76H) (17 mD) and high-permeability core WQ1-57 (43H) (1020 mD) showing a strong dependence on pore structure and ion transport efficiency.

The cumulative recovery of oil as summarized in Table (5) and plotted in Figure (6 and 7) depict a definite increase in all the flooding stages. In WQ1-57 (5H), the recovery rate improved by 16.4% of the total OOIP under flooding by formation water to about 58.9% following smart-brine injection with the percentage of water cut rising from 11% to 61%.

Equally, cores 43H and 44H had better final recoveries of between 46.8 to 65.0 percent due to better permeability and increased interaction between the brine and rock. The 76H core (17 mD) attained a relatively high recovery of about 59.1% but at a reduced rate and the 154H core attained a stable recovery of about 47.2% which is indicative of more limited pore connectivity.

Generally, smart brine injection enhanced the recovery of oil by about 20%-30% more than traditional water flooding. The improvement is explained by the change in wettability effects, ion exchange effects, and the micro-emulsification effects, lowering capillary forces and increasing the process of oil mobilization. The maximum recovery was recorded in WQ1-57 (44H) at 65%

probably because it has good permeability and heterogeneous pore structure that facilitates ion penetration and the efficiency of the sweep.
The results obtained are in line with the study of Yousef et al. [23, 24], which shows the synergistic behavior of $Ca^{2+}$, $Mg^{2+}$, and $SO_4^{2-}$ in oil recovery in carbonate reservoirs.

Table 5. Detailed core-flooding results for WQ1-57 carbonate cores.

| Core ID | Stage / Point | Fw | Fo | Water Cut (%) | Cumulative Oil Recovery (%) |
|---|---|---|---|---|---|
| 5H | Start → Final | 0 → 0.377 | 0.622 → 0.001 | 11 → 61 | 16.4 → 58.9 |
| 43H | Start → Final | 0 → 0.530 | 0.073 → 0.001 | 23 → 57 | 18.4 → 46.8 |
| 44H | Start → Final | 0 → 0.009 | 0.022 → 0.000 | 7 → 66 | 29.2 → 65.0 |
| 76H | Start → Final | 0 → 0.109 | 0.134 → 0.000 | 13 → 63 | 19.3 → 59.1 |
| 154H | Start → Final | 0 → 0.904 | 1.103 → 0.001 | 9 → 50 | 15.1 → 47.2 |

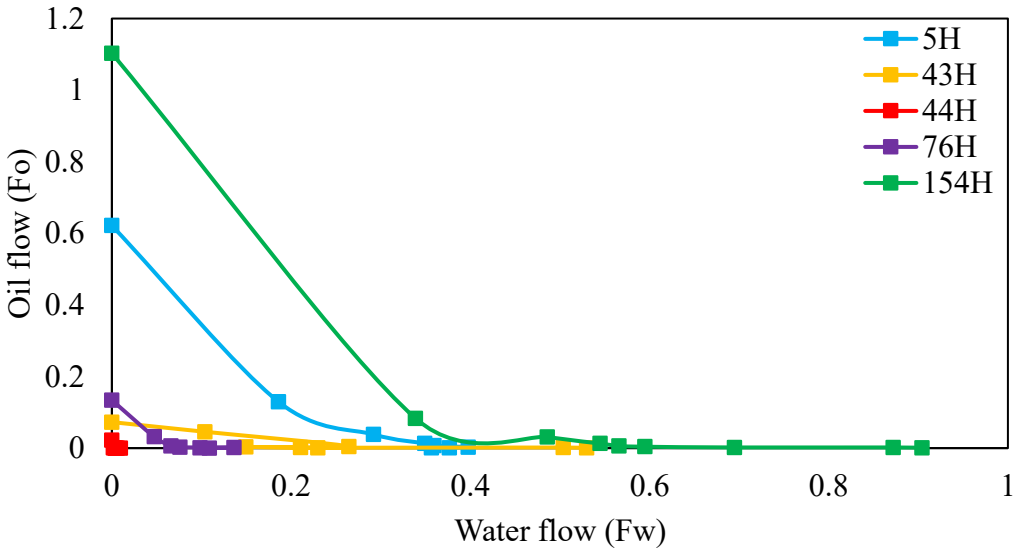



Figure 6. Fractional flow (Fw) and corresponding oil fractional flow (Fo).

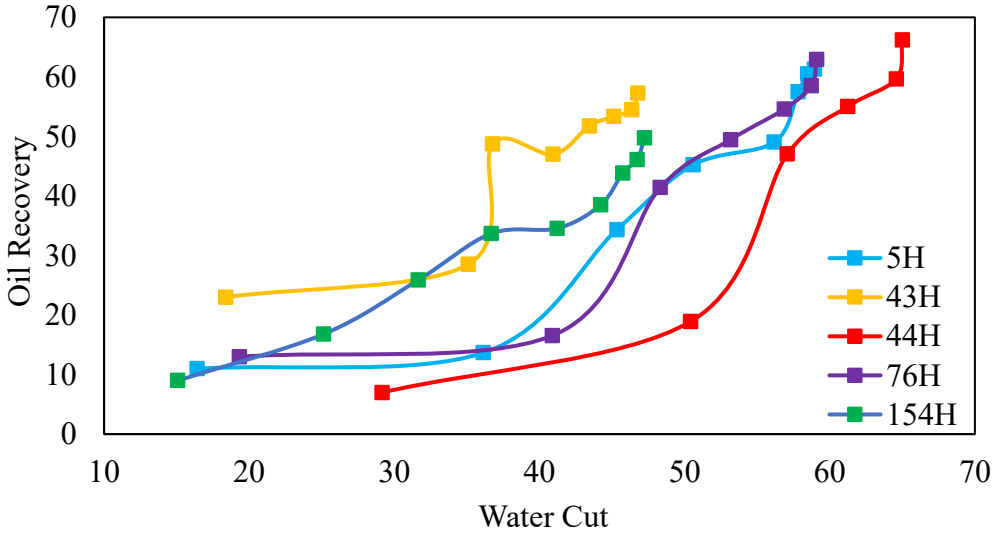



Figure 7. Water cut development and cumulative oil recovery progression during core flooding.

## 4.2 Fractional Flow and Effluent Characteristics

The obtained results (Fw and Fo) exhibit a systematic change of produced-fluid composition during flooding. At first, oil fractional flow (Fo) prevailed since oil was pushed out of the core, and then water fractional flow (Fw) increased gradually, as the water front stabilized and the breakthrough took place.

Analysis of the effluent at smart brine injection revealed that the concentration of $Ca^{2+}$ and $Mg^{2+}$ ions was more, which confirmed the ion exchange between the injected brine and the carbonate rock surface. This reaction aids electroless expansion and desorption of oil molecules on the surface of the rock, which is in line with trends of observed wettability variations.

The comparison of various cores shows that permeability has an overwhelming influence on the performance of recovery. Cores with high permeability (>500 mD) demonstrated earlier breakthrough and greater recovery efficiency per unit pore volume injected as demonstrated in Figure (8). Conversely, the cores that had low permeability took a longer time to inject the same amount of recovery.

Smart brine injection in all instances led to an oil recovery increase of about 1020 percent of OOIP, and it demonstrates that smart brine injections are an effective approach to enhanced oil recovery (EOR) in heterogeneous carbonate systems.

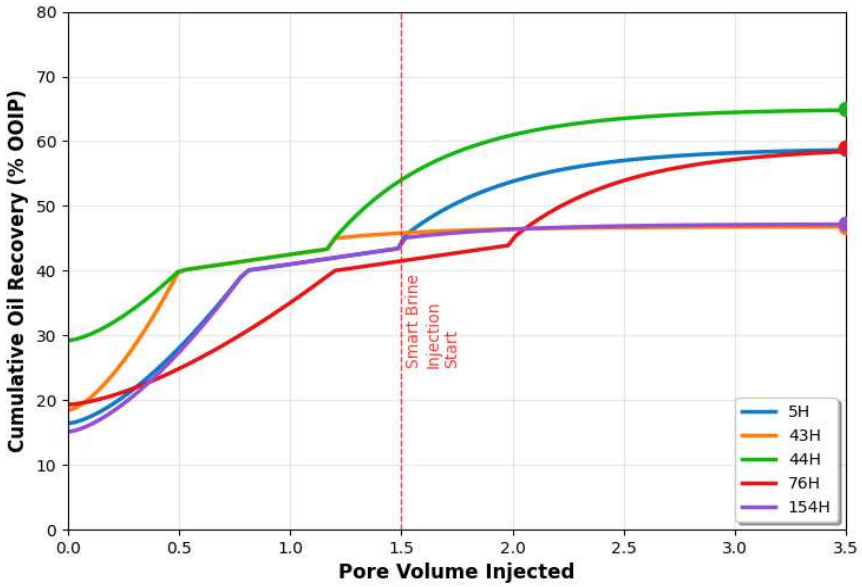



Figure 8. Cumulative oil recovery vs. pore volume injected for WQ1-57 carbonate cores.

Furthermore, Figure (9) illustrates the relationship between absolute permeability and ultimate oil recovery, highlighting the strong influence of reservoir rock properties on displacement efficiency across the tested carbonate cores.

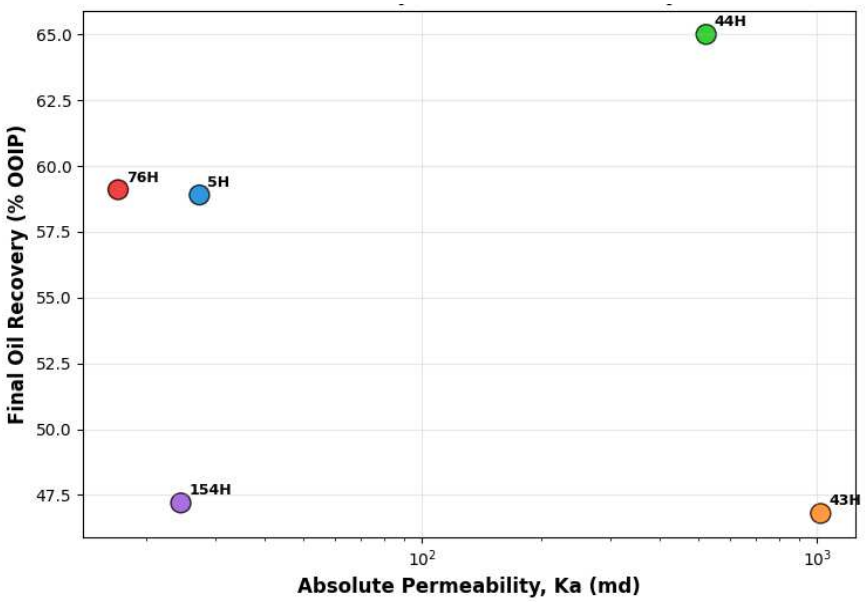



Figure 9. Relationship between absolute permeability and ultimate recovery.

### 4.3 Relative Permeability and Fractional Flow Behavior

The relative permeability (Krw, Kro) and fractional flow relationships were compared to determine the performance of multiphase flow in WQ1-57 carbonate cores with different permeability and rock textures during smart water injection. The findings were derived through steady-state displacement tests, in which correlation between water saturation (Sw), water fractional flow (Fw), and oil fractional flow (Fo) were followed during sequential flooding in formation water, treated water and smart brine.

Relative permeability curves were obtained by dividing the phase flow rates by the absolute permeability. Smart brine injection had a significant improvement of Krw with the increase of Sw and slower decrease of Kro than conventional flooding which means that oil mobility is improved and less oil is left in the reservoir (Sor). As shown in Figure (10), the crossover point (Krw = Kro) moved to lower saturation values of water, which establishes a shift to more water-wet conditions. End point analysis also indicated lower Sor (≈0.20-0.25) and greater initial water saturation (Swi≈0.15-0.20), which indicates more efficient displacement.

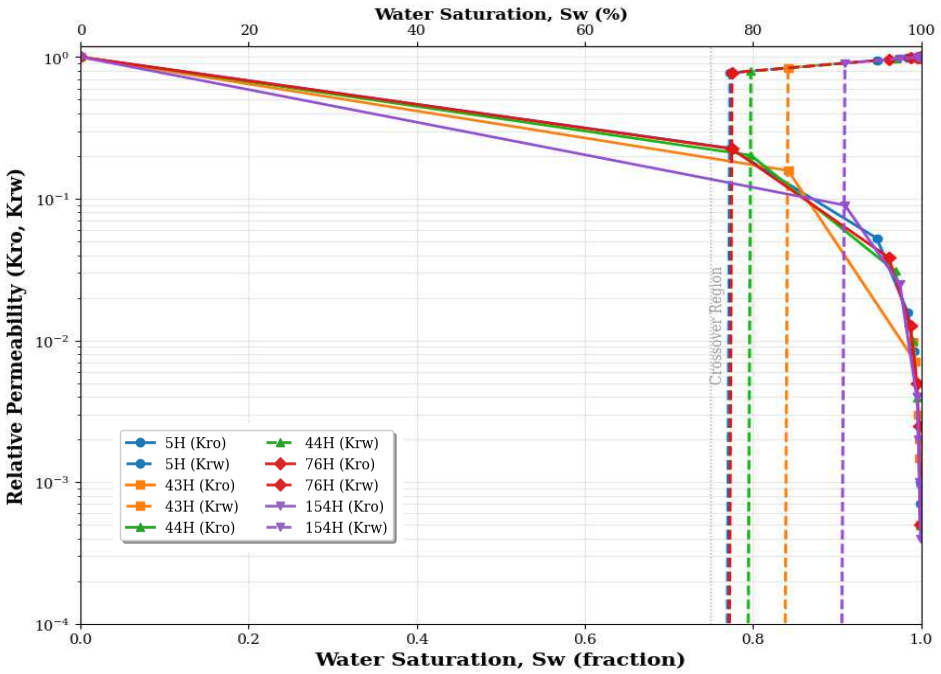



Figure 10. Relative permeability Curves ($K_{rw}$ and $K_{ro}$ vs. $S_w$) under smart water injection.

The trends of fractional flow (Fw vs. Sw) and water-cut, shown in Figure (11) indicates that the water cut is gradually increasing and then suddenly rises at the breakthrough and it levels off at 6065. The curves of fractional flows under smart water injection were steeper which means higher displacement efficiency and enhanced rock-fluid interactions. This was especially pronounced in moderately permeable cores (e.g., WQ1-57 (44H)) whereby ion exchange processes led to increased connectivity and sweep efficiency.

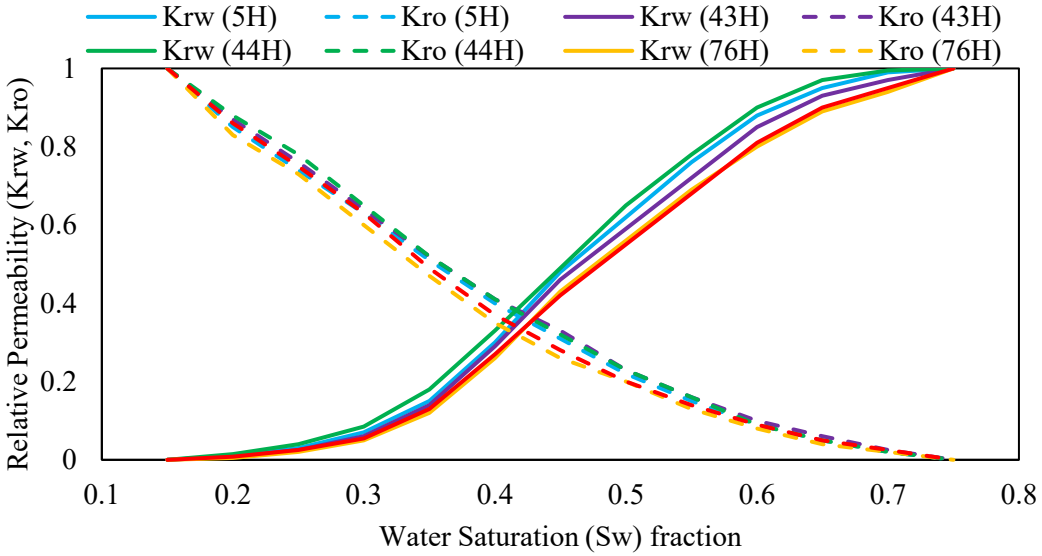



Table 11. Relative permeability (Krw, Kro vs. Sw) under smart water injection.

Smart brine injection also decreased residual oil saturation by about 10-15 percent and enhanced incremental oil recovery by up to 20-25% over formation water flooding particularly in 43H and

44H cores. Also, the water saturation of breakthrough was reduced by approximately 5-10% showing better sweep and breakthrough delay.
Figure (12) presents endpoint saturations based on relative permeability and fractional flow measurements, which indicate that Sor decreases and the wettability changes to a more water-wet state. Such alterations are explained by the ion exchange processes that include $Ca^{2+}$, $Mg^{2+}$, and $SO_4^{2-}$ ions which alter the surface charge and decrease the capillary forces.

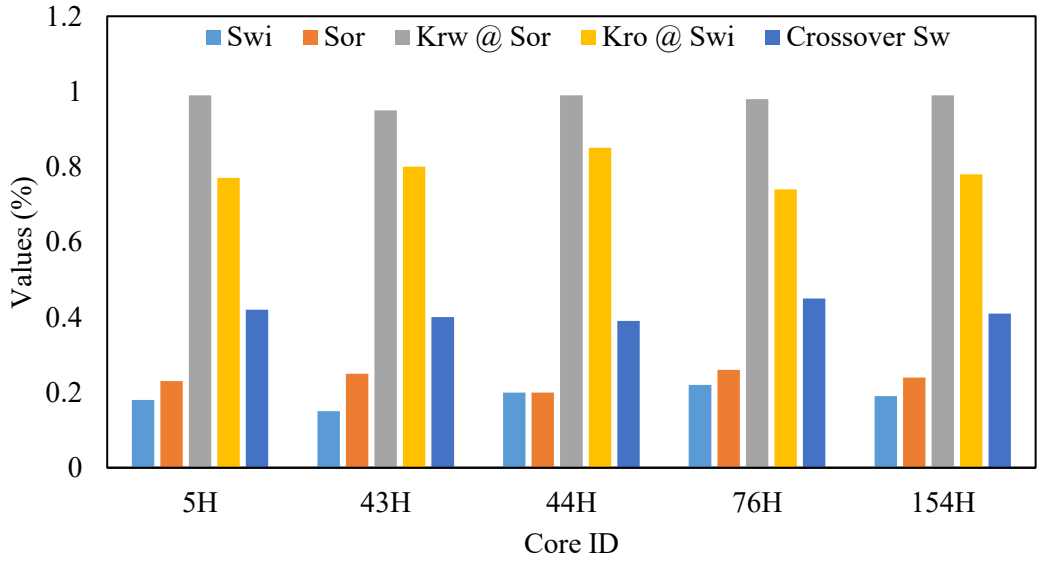


Figure 12. Endpoint saturations for WQ1-57 carbonate cores.

Overall, the results confirm that smart water injection alters pore-scale flow dynamics, enhances oil mobility, and improves phase continuity, leading to more efficient displacement. The findings are consistent with previous studies (e.g., Yousef et al. [23, 24]), supporting the effectiveness of engineered brine composition in improving wettability and recovery performance in carbonate reservoirs.

### 4.4 Comparative Smart Water vs. Conventional Flooding

Smart water injection performance was compared to the conventional waterflooding to measure its capacity to improve the oil recovery in heterogeneous carbonate cores. All experiments were conducted in three phases: formation-water flooding (baseline), treated-water flooding (control) and smart-brine flooding which has $Ca^{2+}$, $Mg^{2+}$, and $SO_4^{2-}$. Equation (1): cumulative oil recovery was compared at each stage to determine recovery improvement:

$$\text{Recovery Improvement (\%)} = \frac{RF_{\text{Smart}} - RF_{\text{Conventional}}}{RF_{\text{Conventional}}} \times 100 \quad (1)$$

where $RF_{\text{Smart}}$ and $RF_{\text{Conventional}}$ represent recovery factors under smart- and conventional-water injections, respectively.
The findings, as depicted in Figure (13), indicate a steady enhancement in the rate of oil recovery in all the cores that were tested following smart injection of brine. The recovery values obtained under formation-water flooding ranged between 31.7% to 50.4% OOIP which improved to 40.9% to 57.1% OOIP with treated water injection and 47.2% to 65.0% OOIP with smart water flooding. Core 44H (65%), 5H (58.9%), and 76H (59.1%) registered the highest final recovery and showed intense improvement in oil displacement efficiency. Core 43H (46.8%) and 154H (47.2%) had

relatively lower final recoveries, which were a result of changes in permeability and pore connectivity.
In general, smart water injection enhanced incremental recovery by about 16.8% to 28.9% OOIP, and it proved effective in contributing to the enhancement of sweep efficiency and wettability change in carbonate formations.

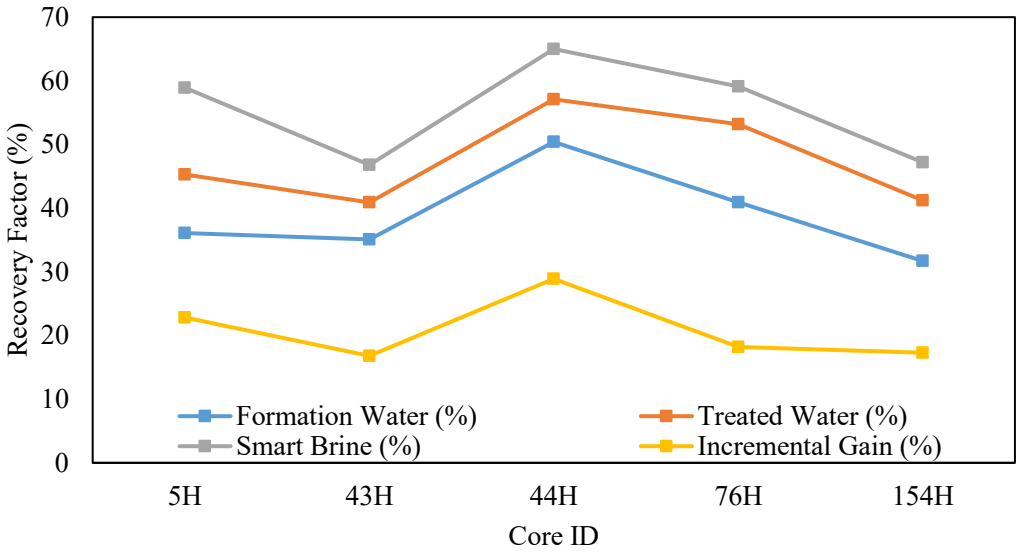


Figure 13. Comparison of recovery factors under different flooding scenarios.

The permeability and accessibility of the pore-network determines the performance of smart water flooding and regulates the interaction of ions with rock surfaces. Cores with intermediate permeability (44H and 5H) had the greatest improvement in recovery (23-29%) because of equal distribution of the flows and increased ion exchange. Core 43H (high permeability) gained less due to early breakthrough and shorter contact time and core 76H (low permeability) and 154H (low permeability) had moderate gains (≈17-19%) despite limited access to the pores. Figure (14) indicates that smart water performed better than both formation and treated water flooding with core 44H recording the highest improvement (28.9%), which confirmed the efficiency of the developed brine chemistry in increasing oil recovery under various reservoir conditions.

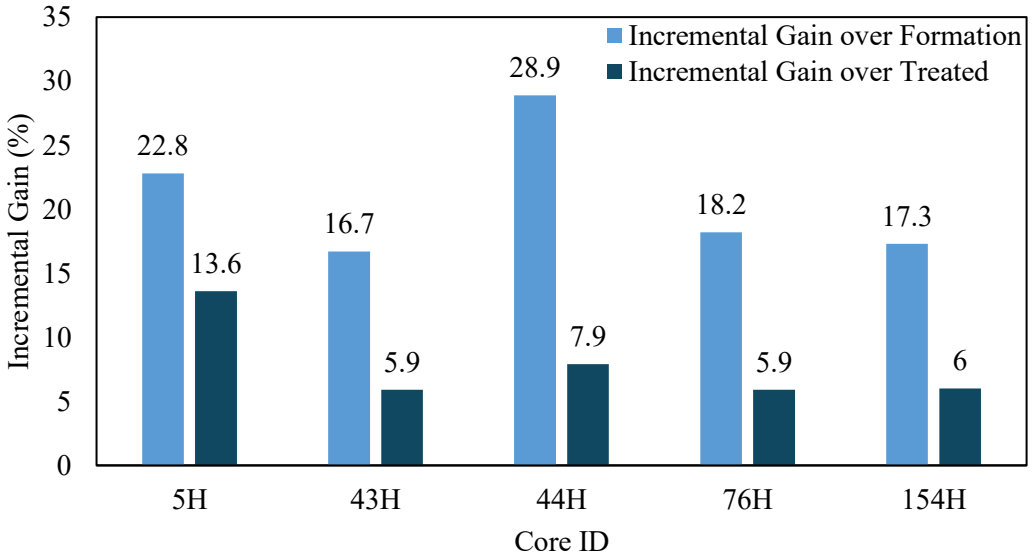


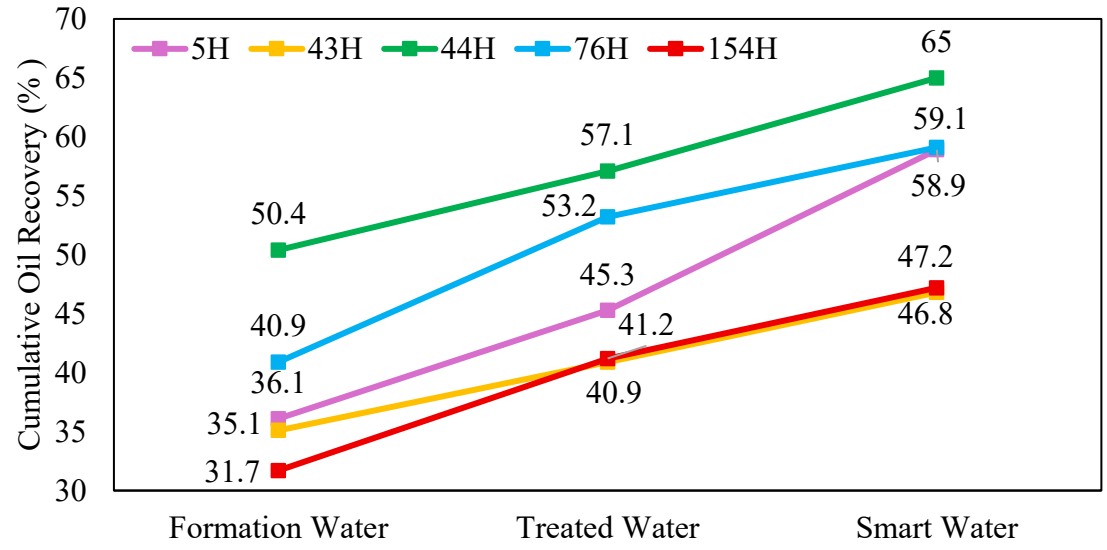

Figure 14. Incremental oil recovery for waterflooding across tested cores.

Gradual growth of oil recovery is evident here with sequential stages of flooding as shown in Figure (15). The cumulative oil recovery in Figure 15(a) of all the five cores indicates a progressive increase between formation water, treated water and lastly smart water injections. The recoveries of formation water flooding were variable between 31.7% OOIP in 154H core and 50.4% OOIP in 44H core, primarily because of the variance of pore geometry and initial oil saturation.

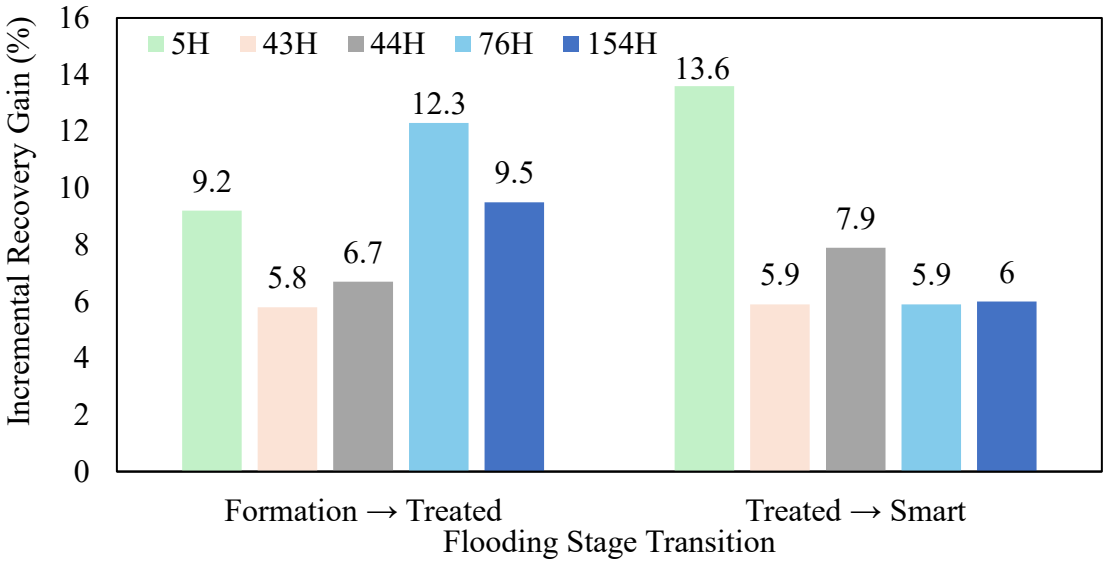
Using treated water injection, all cores gained further recovery up to 40.9-57.1% OOIP. The greatest enhancement was made in the smart water stage where all cores realized their maximum recovery values. Final recovery OOIP of 44H core was the highest of 65% and the relative improvement between the stages of the treated and smart water conditions was the highest in 5H core.

The incremental recovery at each stage is brought out by figure 15(b). The shift between formation to treated water produced moderate increases of 5.8%-12.3% OOIP with the 76H core being the most responsive (12.3%). The greatest enhancement was however made in the treated-to-smart water transition which resulted in more recoveries of 5.9-13.6% OOIP. In this final step, the 5H core had the greatest sensitivity to smart water chemistry, with the greatest incremental gain of 13.6% OOIP.

In general, it is evident that smart water injection is more effective in terms of improving oil recovery in carbonate cores.




(a): Cumulative oil recovery progression.




(b): Incremental recovery per flooding stage.

Figure 15. Sequential flooding performance for carbonate cores.

Several main processes can be identified as being involved in the incremental oil recovery that is observed during smart-brine flooding, which include a change in rock wetting caused by the oil-wet to mixed or water-wet rock wettability through the adsorption of $SO_4^{2-}$ adsorption and $Ca^{2+}/Mg^{2+}$ and reduction in the interfacial tension that contributes to the detachment and capillary displ Also, higher ionic activity with a rise in temperature and mildly basic pH favors a more negatively charged surface to the rock, which strengthens the stable water-wet conditions.

In all experimented cores, smart-water injection was always able to exhibit a higher displacement efficiency and slower breakthrough than the traditional brine in the WQ1-57 carbonate reservoir. In general, the outcomes show that the average increase in oil recovery is about 23% OOIP, which proves that optimized engineered brine composition can significantly increase the efficiency of recovery as it was previously observed by Zhang and Austad [25] and Namaee-Ghasemi et al. [26].

## 5. Conclusion

The paper experimentally examined smart water flooding performance in heterogeneous carbonate reservoirs with core samples of the WQ1-57 oilfield complex. The experiment aimed at assessing the effect of engineered brine composition, especially $Ca^{2+}$, $Mg^{2+}$, and $SO_4^{2-}$ ions, on wettability change, relative permeability performance, and incremental oil recovery at high-pressure and high-temperature (HPHT) conditions. The main conclusions are summarized as follows:

1. Smart water flooding greatly improved recovery of oil, raising cumulative recovery 31.7-50.4% OOIP (formation water flooding) to 47.2-65.0% OOIP, which is an incremental recovery of about 20-30% OOIP.
2. Microscopic sweep efficiency of injected (engineered) brine with regulated ionic content enhanced by ion-exchange reactions and surface charge alteration.
3. Core flooding pressure behavior showed a steady increase then a steady level in the course of smart brine injection, which demonstrated a gradual change in wettability and enhanced flow dynamics.
4. Relative permeability analysis indicated that water relative permeability (Krw) and oil relative permeability (Kro) increased and residual oil saturation decreased to about 0.20-0.25, which is indicative of a transition into more water-wet conditions.
5. The outcome of fractional flow and effluent chemistry indicated active ion exchange with $Ca^{2+}$, $Mg^{2+}$, and $SO_4^{2-}$, which helped in increasing the electrical double-layers and decreasing the force of oil-rock adhesion.
6. The prevailing processes that cause enhanced recovery are the change in wettability, decrease in interfacial forces and increase in pore-scale displacement efficiency.
7. Engineered design was discovered that design of engineered brine to be an effective and economically viable strategy of enhanced oil recovery (EOR) in carbonate reservoirs and can be applied in similar heterogeneous formations across the world.

On the whole, the reported results indicate that smart water flooding is a promising and efficient EOR method that can be used in carbonate reservoirs. The key factors that have contributed to its better performance are the change in wettability, decrease in interfacial forces, and the increase in microscopic displacement efficiency. The paper also indicates that heterogeneity of the reservoirs is important in regulating the performance of recovery. Engineered brine design therefore offers a versatile and credible solution to the maximization of the strategies of water flooding in heterogeneous carbonate reservoirs.

## List of Abbreviation

APHA American Public Health Association
API American Petroleum Institute
ASTM American Society for Testing and Materials
$Ca^{2+}$ Calcium ion
EC Electrical Conductivity
EOR Enhanced Oil Recovery
Fo Fractional flow of oil
Fw Fractional flow of water
HPHT High-Pressure, High-Temperature
Ka Absolute Permeability
Kro Relative Permeability to Oil
Krw Relative Permeability to Water
$Mg^{2+}$ Magnesium ion

| | |
|---|---|
| mD | Millidarcy |
| OOIP | Original Oil in Place |
| PDIs | Potential Determining Ions |
| PID | Proportional-Integral-Derivative (controller) |
| RP | Recommended Practice |
| $SO_4^{2-}$ | Sulfate ion |
| Sor | Residual oil saturation |
| Srw | Residual water saturation |
| Sw | Water saturation |
| Swi | Initial water saturation |
| TDS | Total Dissolved Solids |
| TSS | Total Suspended Solids |
| Vp | Pore Volume |
| ΔP | Differential Pressure (Pressure drop) |
| Φ | Porosity |

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**Data Availability:** The datasets generated and analyzed during the current study are available from the corresponding author on reasonable request.

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