

**EVALUATING THE IMPACT OF SMART WATER FOR ENHANCED OIL  
RECOVERY IN A TIGHT RESERVOIR**



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## CERTIFICATION

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## **DEDICATION**

This project is dedicated to the Almighty God, whose grace, wisdom, and guidance have made this journey possible. I also dedicate it to my beloved parents, whose endless love, prayers, and support have been my greatest source of strength and inspiration.

## **ACKNOWLEDGEMENT**

First and foremost, I give thanks to the almighty God for his guidance, strength, and grace throughout the course of this project. I would like to express my sincere gratitude to my project supervisor DR. Oluwaseun Taiwo for his valuable time, guidance, constructive feedback, and constant encouragement throughout the duration of this work. His insight and expertise greatly contributed to the success of this project.

## ABSTRACT

Tight reservoirs contain a large amount of hydrocarbon resources, but producing oil from them is often difficult because of their very low permeability and complex pore structure. Conventional water flooding is commonly used to maintain reservoir pressure and displace oil; however, in tight formations it usually results in low oil recovery due to restricted fluid flow and strong capillary forces. Because of this limitation, there is growing interest in improved water flooding techniques such as smart water injection.

This study evaluates the impact of smart water injection on oil recovery in a tight sandstone reservoir using numerical reservoir simulation. A synthetic reservoir model representing a typical tight sandstone formation in the Niger Delta was developed using the Computer Modelling Group (CMG) GEM simulator. Two injection scenarios were considered under the same reservoir conditions: conventional high-salinity water flooding and low-salinity smart water flooding. The smart water case involved reducing the salinity of the injected brine in order to examine its effect on oil displacement and reservoir performance.

The performance of both injection strategies was analyzed by comparing cumulative oil production, oil recovery factor, water cut, and reservoir pressure over a production period of 45 years. The simulation results show that smart water injection produced a slightly higher oil recovery compared to conventional high-salinity flooding and also delayed the increase in water cut. However, the overall improvement in recovery was relatively small because fluid movement and ion transport are limited in tight sandstone formations.

The results suggest that although smart water injection can improve oil recovery to some extent in tight reservoirs, its effectiveness may be limited when used alone. Combining smart water flooding with other enhanced oil recovery methods may provide better production performance in tight formations.

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# CHAPTER ONE

## INTRODUCTION

### 1.1 Background of the Study

The continuous rise in global energy demand, fueled by population growth, industrialization, and urban expansion, has made efficient hydrocarbon recovery more important than ever (International Energy Agency [IEA], 2021). While renewable energy sources are steadily increasing, crude oil and natural gas are still expected to dominate the global energy supply in the coming decades (U.S. Energy Information Administration [EIA], 2023). Over time, conventional reservoirs that once supplied most of the world's oil have been heavily exploited, making it necessary to focus on unconventional resources such as shale oil and tight reservoirs (Jarvie et al., 2007; Sheng, 2019).

Tight reservoirs have gained global attention because of their abundance, though they are technically challenging to produce. These formations typically have very low permeability (less than 0.1 millidarcy) and low porosity, which restrict the movement of fluids (Morrow & Buckley, 2011; Lake et al., 2014). In such systems, capillary forces dominate, causing oil to be trapped within fine pores. As a result, traditional recovery methods such as natural depletion and normal water flooding usually recover less than 15% of the original oil in place (Sheng, 2013). This low efficiency highlights the need for enhanced recovery methods that can overcome these limitations.

Enhanced Oil Recovery (EOR) techniques such as chemical, gas, and thermal methods have been used to improve production (Alvarado & Manrique, 2010; Dang et al., 2013). However, these methods can be expensive, less effective, and environmentally demanding, especially in tight formations. This has encouraged research into simpler and more sustainable options such as Smart Water Injection (Austad, 2013).

Smart water flooding, sometimes called engineered water injection, involves changing the ionic composition of injected water to improve how oil, water, and rock interact. By adjusting certain ions in the water, such as sodium ( $\text{Na}^+$ ), chloride ( $\text{Cl}^-$ ), and hydrogen ( $\text{H}^+$ ), the injected water can alter the rock surface properties, change wettability, and enhance oil displacement efficiency (Yousef et al., 2011; Nasralla & Nasr-El-Din, 2014).

In sandstone reservoirs, reducing the salinity of injection water expands the electrical double layer around rock surfaces, weakening the adhesive forces between oil and rock. This helps the rock become more water-wet, improving oil mobility and displacement (Tang & Morrow, 1999; Zhang et al., 2020). In carbonate formations, similar processes occur through ion exchange, where the brine reacts with the mineral surface to release trapped oil (Austad et al., 2021). These interactions collectively reduce capillary pressure and enhance overall recovery.

Although smart water injection has been widely tested in conventional sandstones and carbonates, its performance in tight reservoirs is not well understood. The very small pore sizes, low permeability, and limited ion diffusion in tight formations make it harder for chemical reactions to occur effectively (Jerauld et al., 2018; Chen et al., 2020). This uncertainty creates a need to evaluate whether the same mechanisms can work under tight-reservoir conditions.

Advances in simulation tools, especially CMG (Computer Modelling Group), have made it possible to study these mechanisms in detail. CMG's GEM simulator allows the integration of rock–fluid interactions, ionic effects, and reservoir properties to predict EOR performance without the cost and complexity of physical experiments (Dang et al., 2013; Mohammed et al., 2022).

This research therefore focuses on using CMG simulation to study how changing salinity and ion concentration in injection water (Smart Water) affects oil recovery in tight sandstone

reservoirs. The goal is to determine whether modifying the ionic composition of the injected brine can improve recovery performance compared to conventional high-salinity flooding.

## **1.2 Statement of the Problem**

Tight oil reservoirs contain a large share of the world's hydrocarbon resources, but developing them is difficult because of their low permeability, low porosity, and poor fluid mobility (Sheng, 2019). Even after secondary recovery techniques like conventional water flooding, recovery factors rarely exceed 15% (Morrow & Buckley, 2011).

While smart water flooding has been successful in conventional formations, its performance in tight reservoirs remains uncertain. The key EOR mechanisms — ion exchange, wettability alteration, and capillary pressure reduction — rely on ionic movement, which is limited in ultra-tight rocks (Nasralla & Nasr-El-Din, 2014). This makes it unclear whether smart water can produce meaningful recovery under such restricted conditions.

Moreover, most studies available are laboratory-based, focusing on small-scale core flooding experiments that don't fully represent field conditions. There is still a lack of simulation studies that combine geochemical reactions, ionic effects, and reservoir physics to predict recovery outcomes in tight formations (Dang et al., 2013; Mohammed et al., 2022). This study addresses that gap by using CMG simulations to evaluate how salinity and ionic composition influence recovery in tight reservoirs.

## **1.3 Aim of the Study**

The aim of this research is to investigate the potential of Smart Water Injection as an Enhanced Oil Recovery (EOR) strategy for tight reservoirs using CMG simulation. The study focuses on how adjusting the ionic composition of injection water influences rock–fluid interactions such as wettability, surface charge, and capillary behavior.

## **1.4 Objectives of the Study**

The specific objectives of this study are to:

1. Review the mechanisms through which smart water affects oil recovery in tight reservoirs, focusing on wettability alteration, capillary pressure reduction, and rock–fluid interactions.
2. Define and model the ionic composition and key properties of Smart Water and conventional water used for CMG simulation.
3. Build a CMG simulation model of a tight sandstone reservoir, incorporating parameters for porosity, permeability, wettability, and salinity.
4. Compare oil recovery results for Smart Water and High-Salinity water injection, identifying performance trends and improvement potentials.

## **1.5 Significance of the Study**

This study provides insight into how ionic composition and salinity affect recovery in tight reservoirs, helping bridge the gap between theory and field application. From an academic point of view, it contributes to ongoing research on smart water flooding by focusing on ultra-low-permeability systems (Sheng, 2019; Zhang et al., 2020).

For the industry, this research supports better design of EOR operations. Since tight reservoirs hold vast hydrocarbon volumes, even small improvements in recovery factors can add significant economic value (Dang et al., 2013; Mohammed et al., 2022). Simulation-based analysis also reduces cost and risk before full-scale implementation.

Environmentally, smart water flooding offers a cleaner alternative to chemical EOR methods since it only requires adjusting ion concentrations in injection water rather than adding external chemicals (Austad, 2013). This supports more sustainable oil recovery.

## **1.6 Scope and Limitations of the Study**

The study is limited to CMG-based simulation of Smart Water injection in tight sandstone reservoirs. Two main flooding scenarios were modeled:

High-Salinity Water Injection, representing the conventional base case.

Smart Water Injection, representing reduced-salinity flooding with modified Na<sup>+</sup> and Cl<sup>-</sup> composition.

The focus is on recovery efficiency, wettability change, and capillary effects. However, because this is a simulation-based study, real field heterogeneity and complex mineral interactions are simplified. Laboratory data for chemical validation were also limited, so the results are indicative rather than absolute.

## **1.7 Contribution to Knowledge**

This research expands understanding of how Smart Water Injection behaves in tight sandstone systems. It shows how ion reduction and salinity control can influence wettability and displacement efficiency under ultra-low-permeability conditions. It also demonstrates how CMG simulation can serve as a predictive tool for analyzing EOR mechanisms in tight formations.

The study provides a foundation for future experimental validation, identifies key operational parameters, and offers practical insight for improving recovery in tight oil reservoirs using a cost-effective and environmentally friendly approach

## 1.8 Definition of Terms

**Tight Reservoir:** A petroleum-bearing rock formation with very low permeability, typically less than 0.1 millidarcies (mD), where oil and gas do not readily flow to a wellbore without advanced stimulation techniques like hydraulic fracturing.

**Enhanced Oil Recovery (EOR):** A suite of techniques used to increase the amount of crude oil that can be extracted from an oil field beyond what is achievable by primary and secondary recovery methods.

**Smart Water Injection / Engineered Water Injection:** An EOR technique involving the injection of brine whose ionic composition has been specifically designed to trigger physicochemical changes at the rock-fluid interface to improve oil displacement.

**Wettability:** The tendency of a fluid to spread on or adhere to a solid surface in the presence of other immiscible fluids; it is a measure of whether the rock is water-wet, oil-wet, or mixed-wet.

**Salinity:** The total concentration of dissolved salts in water, typically measured in parts per million (ppm) or milligrams per liter (mg/L).

**Ionic Composition:** The specific types and concentrations of ions (e.g.,  $\text{Na}^+$ ,  $\text{Ca}^{2+}$ ,  $\text{Mg}^{2+}$ ,  $\text{SO}_4^{2-}$ ,  $\text{Cl}^-$ ) present in a brine.

**Capillary Pressure ( $P_c$ ):** The pressure difference across the interface between two immiscible fluids in a porous medium, which is a strong function of wettability and pore throat size. In tight rocks, capillary pressures are very high.

**Relative Permeability:** A dimensionless measure of the effective permeability of a fluid phase at a given saturation, which governs the simultaneous flow of multiple fluids in a reservoir.

CMG (Computer Modelling Group): A leading developer of reservoir simulation software, including the GEM (compositional and unconventional simulator), IMEX (black-oil simulator), and WinProp (fluid characterization) tools used in this study.

Recovery Factor (RF): The percentage of the Original Oil in Place (OOIP) that is ultimately recovered.

## CHAPTER TWO

### LITERATURE REVIEW

#### 2.1 Introduction

This chapter fulfills the first objective of the research—to provide a comprehensive review of how smart water injection enhances oil recovery in tight reservoirs, with emphasis on three main mechanisms: wettability alteration, capillary pressure reduction, and rock–fluid interactions.

Smart water injection has gained increasing attention in recent years as a promising and environmentally friendly enhanced oil recovery (EOR) technique. Unlike chemical EOR processes that depend on the addition of surfactants or polymers, smart water injection modifies the ionic composition of the injected brine to stimulate beneficial physicochemical reactions at the rock–fluid interface. These interactions can improve rock wettability, reduce capillary pressure, and increase oil mobility—ultimately improving displacement efficiency and total recovery (Yousef et al., 2011; Sheng, 2019; Zhang et al., 2020).

Tight reservoirs, characterized by extremely low permeability ( $<0.1$  mD) and complex pore structures, present unique recovery challenges (Morrow & Buckley, 2011). Fluid flow in such formations is controlled by strong capillary forces and nano-scale pore systems that trap hydrocarbons, making conventional water flooding inefficient. Consequently, understanding the petrophysical nature of tight reservoirs and how smart water injection interacts with their rock–fluid systems is crucial for optimizing recovery performance.

This chapter therefore reviews:

1. The petrophysical characteristics of tight reservoirs;
2. Conventional and emerging EOR methods used in such formations; and

3. The mechanisms and governing principles of smart water injection, particularly as they apply to tight formations modeled in this study using CMG simulation

## **2.2 Petrophysical Characteristics of Tight Reservoirs**

Tight reservoirs belong to the class of unconventional hydrocarbon systems and are characterized by low porosity, very low permeability, and poor natural pore connectivity. Typically, the matrix permeability ranges from 0.001 to 0.1 millidarcy (mD), while porosity values are often below 10% (Jarvie et al., 2007; Lai et al., 2018). These properties create high capillary pressures and restrict fluid flow, which leads to poor recovery efficiency under conventional primary or secondary methods.

Porosity in tight reservoirs is largely influenced by depositional environment and diagenetic processes such as compaction, cementation, and clay transformation. Compared to conventional sandstones, tight formations contain a higher fraction of clay minerals (e.g., illite, kaolinite, and smectite), which block pore throats and reduce effective pore space (Zou et al., 2019). The presence of these clays also affects the surface charge of the rock, directly influencing wettability and the success of water-based recovery processes (Jerauld et al., 2018).

Permeability is governed mainly by micro- and nano-scale pore systems, including intergranular and intercrystalline pores and microfractures. Because these channels are extremely narrow, fluid flow often deviates from Darcy's law and may follow non-Darcy or slip-flow mechanisms (Wu et al., 2017). The narrow pore throats also generate high capillary entry pressures, preventing easy movement of water and oil and leaving behind large amounts of trapped oil after depletion.

A defining feature of tight reservoirs is their high capillary pressure due to small pore sizes and large surface area-to-volume ratios. Even minor changes in surface charge or ionic composition can significantly affect oil displacement efficiency (Zhang et al., 2020). This sensitivity forms

the scientific basis for the use of smart water injection, where carefully controlled ions can modify the electrochemical balance of the rock surface.

Moreover, tight formations display strong heterogeneity and anisotropy, caused by variations in mineral composition, grain size, and fracture networks. These variations create uneven fluid flow paths, which often lead to early water breakthrough and poor sweep efficiency during normal water flooding (Sun et al., 2022).

In summary, the combination of low porosity, low permeability, complex mineralogy, high capillary pressure, and heterogeneity explains the low recovery performance of tight reservoirs. These same properties, however, make tight rocks particularly responsive to ionic modification through smart water injection, which can alter surface forces and reduce trapping effects.

### **2.3 Enhanced Oil Recovery (EOR) Methods in Tight Reservoirs**

Because of poor natural productivity, tight reservoirs require enhanced oil recovery (EOR) techniques to improve oil mobility and overall displacement efficiency. The three main categories of EOR are thermal, gas, and chemical methods (Alvarado & Manrique, 2010). Each modifies fluid or rock properties in specific ways.

#### **2.3.1 Thermal EOR Methods**

Thermal recovery—such as steam flooding, cyclic steam stimulation (CSS), and in-situ combustion—is primarily used in heavy oil reservoirs. It increases oil mobility by lowering viscosity (Green & Willhite, 2018). However, tight reservoirs have such low permeability that heat transfer is inefficient, making thermal recovery technically and economically unfeasible in most cases.

### **2.3.2 Gas Injection Methods**

Gas injection techniques—using CO<sub>2</sub>, N<sub>2</sub>, or hydrocarbon gases—help maintain pressure and improve sweep efficiency (Lake et al., 2014). In miscible flooding, injected gas dissolves into the oil, reducing viscosity and interfacial tension; in immiscible flooding, it simply displaces oil by pressure drive. While CO<sub>2</sub> injection has shown promise in some unconventional reservoirs, tight formations experience injectivity problems and early gas breakthrough due to poor pore connectivity (Ren et al., 2021). Maintaining miscibility at such high pressures is also costly.

### **2.3.3 Chemical EOR Methods**

Chemical flooding—using surfactants, polymers, or alkaline agents—modifies interfacial tension or mobility ratios (Sheng, 2019). In tight formations, however, chemical adsorption, injectivity issues, and high costs reduce their efficiency (Jerauld et al., 2018). Moreover, environmental concerns make large-scale chemical use less attractive.

### **2.3.4 Low-Salinity and Smart Water EOR (Emerging Techniques)**

Recent studies have shifted toward low-salinity water flooding (LSWF) and smart water injection as more sustainable alternatives (Austad et al., 2021). These techniques tailor the ionic composition of brine to influence rock–fluid interactions without external additives. Because smart water injection modifies wettability and capillary behavior through ionic activity, it is an ideal, low-cost, and environmentally friendly method for tight formations—an approach central to this study.

## **2.4 Fundamentals of Smart Water Injection**

### **2.4.1 Concept and Mechanisms**

Smart water injection, also known as engineered water flooding, deliberately adjusts the ionic composition of injection brine to enhance recovery. It differs from conventional flooding in that it targets surface chemistry rather than just pressure maintenance (Austad, 2013; Nasralla & Nasr-El-Din, 2014).

When injected into the reservoir, smart water initiates several interconnected mechanisms:

Electrical double-layer expansion – Low-salinity water increases the distance between charged surfaces on the rock and oil, producing repulsive forces that help detach oil droplets.

Ion exchange – Active ions (e.g.,  $\text{Ca}^{2+}$ ,  $\text{Mg}^{2+}$ ,  $\text{SO}_4^{2-}$ ,  $\text{Na}^+$ ) replace those naturally adsorbed on mineral surfaces, shifting wettability toward water-wet conditions.

Capillary pressure reduction – Altered surface forces and lower interfacial tension allow water to access smaller pores, freeing trapped oil (Tang & Morrow, 1999; Austad et al., 2021).

These effects collectively improve microscopic displacement efficiency and are particularly important in tight formations where capillary trapping dominates.

### **2.4.2 Composition of Smart Water**

The optimal ionic recipe for smart water depends on rock type and fluid chemistry. In sandstones,  $\text{Na}^+$ ,  $\text{Ca}^{2+}$ , and  $\text{Cl}^-$  are often key ions; in carbonates,  $\text{SO}_4^{2-}$ ,  $\text{Mg}^{2+}$ , and  $\text{Ca}^{2+}$  play stronger roles due to interactions with calcite surfaces (Austad et al., 2013). The ionic strength and salinity must be carefully balanced to avoid scaling or clay swelling.

In this study, the low-salinity water (LSW) used in CMG simulation represents a diluted version of the formation brine, with reduced  $\text{Na}^+$  and  $\text{Cl}^-$  concentrations to mimic electrical

double-layer expansion effects. The high-salinity case represents the base flooding scenario, used for direct comparison under identical reservoir conditions.

## **2.5 Mechanisms of Smart Water Flooding**

Smart water flooding—also known as ion-engineered water injection—is effective because it activates several physicochemical mechanisms that act simultaneously. The three major mechanisms are wettability alteration, capillary pressure reduction, and rock–fluid interactions.

### **2.5.1 Wettability Alteration**

Wettability alteration is considered the dominant mechanism of smart water flooding (Kilybay et al., 2017). In many tight reservoirs, rock surfaces are initially oil-wet, meaning that oil strongly adheres to mineral grains. When brine composition is altered—for instance, by increasing sulfate ( $\text{SO}_4^{2-}$ ) or reducing sodium ( $\text{Na}^+$ ) ions—the electrostatic balance at the surface shifts, leading to weaker oil adhesion. Experiments show that removing monovalent ions or enriching divalent ones (such as  $\text{Ca}^{2+}$  and  $\text{Mg}^{2+}$ ) can reduce contact angles and shift wettability toward water-wet conditions (Noorizadeh Bajgirani et al., 2023).

### **2.5.2 Capillary Pressure Reduction**

In tight formations, high capillary pressure traps significant volumes of oil in micro-pores. Smart water helps reduce this pressure by modifying interfacial tension (IFT) and making surfaces more water-wet. The reduced IFT allows water to access smaller pores, while the wettability change lowers capillary resistance (Sukee et al., 2022; Kassa et al., 2019). Together, these effects make trapped oil easier to mobilize.

### **2.5.3 Rock–Fluid and Ion Exchange Interactions**

When smart water contacts the rock, ion exchange occurs between injected ions and those bound to mineral surfaces. For example, sulfate ions ( $\text{SO}_4^{2-}$ ) can displace  $\text{Ca}^{2+}$  or  $\text{Mg}^{2+}$  attached

to organic molecules on the rock surface, weakening the electrostatic bond that holds oil. Additionally, slight mineral dissolution or re-precipitation can change surface roughness and pore connectivity, improving flow paths (Bastos et al., 2022).

In this study's CMG simulation, these mechanisms were modeled by adjusting relative permeability and capillary pressure curves based on salinity-dependent wettability indices, allowing direct comparison between high- and low-salinity cases.

## **2.6 Role of Numerical Simulation in Smart Water Evaluation**

Numerical simulation plays a vital role in evaluating EOR methods. Using advanced software such as CMG-GEM, researchers can model complex processes like ion exchange, wettability alteration, and capillary behavior under controlled conditions (Dang et al., 2013).

Simulation allows the quantification of individual mechanisms—such as electrical double-layer expansion—and the testing of different ionic compositions and injection rates to determine optimal conditions. For tight reservoirs, simulation is especially useful because laboratory experiments often cannot replicate nano-scale pore interactions or long-term reservoir behavior.

In this study, CMG simulation was applied to analyze the effect of varying salinity levels on oil recovery in a Niger Delta tight sandstone reservoir. The approach enabled the investigation of how low-salinity water flooding influences recovery factor, cumulative oil production, wettability behavior, and capillary response compared to high-salinity flooding.

## **2.7 Summary of Literature Gaps and Relevance To This Study**

A review of previous research shows that while smart water injection has been widely studied and successfully applied in conventional sandstone and carbonate reservoirs, its effectiveness

in tight formations remains less understood and only partially validated. Most existing studies have focused on laboratory-scale core flooding experiments (Tang & Morrow, 1999; Yousef et al., 2011; Austad et al., 2013), which provide valuable mechanistic insights but fail to capture the field-scale complexities of tight reservoirs. These experiments often neglect the combined effects of ion transport limitations, mineral heterogeneity, and long equilibrium times—factors that strongly influence performance under actual reservoir conditions (Jerauld et al., 2018; Chen et al., 2020).

Another major gap in the literature lies in the quantitative modeling of ion–rock–fluid interactions. Although several studies have described the fundamental mechanisms—such as electrical double-layer expansion, ion exchange, and surface charge modification—few have integrated these into numerical reservoir simulations that account for real reservoir heterogeneity and time-dependent processes. This has limited the industry’s ability to predict recovery efficiency or optimize smart water composition for tight formations (Mohammed et al., 2022).

Additionally, while previous research has emphasized wettability alteration as the dominant mechanism, the combined effects of wettability change, capillary pressure reduction, and ion diffusion constraints in tight rock systems are not well-documented. The interplay among these mechanisms is particularly critical for understanding why the recovery improvements observed in laboratory settings are often less pronounced in tight reservoir applications (Zhang et al., 2020; Austad et al., 2021).

Therefore, there is a clear need for simulation-based investigations that:

1. Integrate rock–fluid interaction models with realistic tight reservoir parameters;
2. Quantify how salinity and ion concentration influence recovery efficiency; and

3. Identify key operational conditions (such as injection rate and ion composition) that optimize performance while maintaining economic feasibility.

This study addresses these research gaps by using Computer Modelling Group (CMG) simulation software to evaluate and compare smart water and conventional high-salinity flooding under identical reservoir conditions. By coupling geochemical modeling with fluid flow simulation, the study provides a detailed understanding of how low-salinity water injection impacts oil recovery, wettability alteration, and capillary behavior in a representative tight sandstone reservoir of the Niger Delta.

Ultimately, this research contributes both theoretical and practical insights toward the design and application of smart water injection in tight formations, supporting the industry's broader goal of improving recovery efficiency through cost-effective and environmentally sustainable EOR technologies.

## CHAPTER THREE

### METHODOLOGY

#### 3.1 Research Design and Framework

This chapter explains the materials, procedures, and simulation steps used in this study. The goal is to clearly describe how the reservoir model was created and how the simulations were performed to evaluate the effect of Smart Water injection on oil recovery in a tight sandstone reservoir.

The research followed a simulation-based design using the Computer Modelling Group (CMG) software to study how changes in water salinity and ion composition affect oil recovery. The CMG GEM module was selected because it can handle complex rock–fluid interactions, phase behavior, and chemical reactions that are important when studying Smart Water injection in tight formations.

The overall framework of the research was divided into four main stages:

1. Model Development: Building a representative tight reservoir model that reflects the properties of low-permeability sandstone formations.
2. Fluid System Characterization: Defining the physical and thermodynamic properties of the oil, gas, and water phases.
3. Simulation Scenario Design: Creating and running two main flooding cases—High-Salinity (HSW) and Low-Salinity/Smart Water (LSW)—under the same reservoir and operational conditions.
4. Performance Analysis: Comparing and analyzing the simulation outputs, such as oil recovery factor, cumulative oil production, water cut, and economic performance, to evaluate the efficiency of Smart Water injection.

This structured approach ensured that each stage of the study was systematically performed and that the results from the simulations could be directly compared to draw reliable conclusions.

### **3.2 Materials and Models Used**

The study was entirely simulation-based, meaning that all experiments were carried out digitally using the CMG software suite. No physical laboratory experiments were conducted.

The software tools and materials used are described below:

#### **1. CMG GEM (General Equation of State Model):**

This was the main simulation tool used to model the tight reservoir system. It was chosen because of its ability to simulate multiphase flow and to account for compositional and geochemical effects, including ionic interactions between injected Smart Water and reservoir rock.

#### **2. CMG Builder:**

The Builder module was used to construct the three-dimensional reservoir grid. It allowed for defining reservoir geometry, layer dimensions, porosity, permeability, initial pressure, and fluid saturations.

#### **3. CMG WinProp:**

This module was used to define the thermodynamic and physical properties of the fluids—oil, gas, and water—under varying pressure and temperature conditions. It generated the PVT (pressure–volume–temperature) data required for the GEM simulator.

#### **4. CMG Results Viewer:**

After running the simulations, this tool was used to visualize and analyze results, including oil production rates, cumulative oil recovery, water cut, and pressure changes over time.

## 5. Microsoft Excel and Word:

These were used for organizing and processing the simulation data, performing basic calculations, and preparing graphs and tables for reporting and analysis.

These digital tools provided a stable and efficient simulation environment, allowing for a detailed investigation of Smart Water and High-Salinity flooding under identical reservoir conditions.

### **3.3 Data Collection and Preparation**

All the data used for this study were obtained from published research papers, textbooks, and technical reports related to smart water flooding and tight reservoir development. Since this project was not based on a specific field dataset, a synthetic model was developed to represent a typical tight sandstone reservoir.

The data collected included key reservoir parameters such as geometry, porosity, permeability, pressure, and temperature, as well as fluid properties like density, viscosity, and composition. These values were compiled into tables and formatted for input into CMG Builder and WinProp.

Before importing the data into GEM, all input parameters were carefully checked to ensure they were realistic and consistent with tight reservoir characteristics. For instance, permeability values were kept within 0.001–0.1 millidarcy (mD), and porosity values were between 5–10%, which reflect typical tight formation conditions. This preparation ensured that the simulation would produce reliable and representative results.

### **3.4 Reservoir Model Construction**

The reservoir model used in this study represents a tight sandstone formation typical of the Niger Delta region. The rock is mainly composed of quartz and kaolinite, two minerals

commonly found in such formations. Quartz forms the strong framework of the rock, providing structural stability, while kaolinite—a type of clay—significantly affects rock–fluid interactions.

Kaolinite tends to adsorb the polar components of crude oil, making the rock oil-wet and trapping oil in small pores, which makes recovery difficult during conventional water flooding. To address this problem, a Smart Water (low-salinity) formulation was designed by diluting the formation brine and adjusting its ionic composition to promote wettability alteration. The goal was to reduce the total dissolved solids (TDS) and allow ion exchange between the injected brine and the rock surface, thereby converting the rock from oil-wet to more water-wet and improving oil mobility.

The High-Salinity (HSW) water served as the baseline case, representing normal formation brine with higher concentrations of  $\text{Na}^+$  and  $\text{Cl}^-$ , maintaining the initial reservoir conditions without ionic modification.

### **3.5 Model Representation Setup**

In the CMG simulation, the effect of quartz and kaolinite was captured through definitions of relative permeability, capillary pressure, and wettability parameters. The model reflected the limited ion movement and slow surface reactions typical of tight reservoirs.

Both Smart Water and High-Salinity brines were assigned their respective ionic compositions in the simulation. Although CMG does not directly simulate mineral-surface chemistry, the rock–fluid interaction settings were adjusted to represent the expected wettability changes caused by Smart Water injection. This approach provided a realistic representation of how low-salinity flooding behaves in a quartz–kaolinite-dominated tight reservoir.

### **3.6 Initialization and Rock–Fluid Definition**

After constructing the reservoir grid, the model was initialized by setting the starting conditions of the reservoir before injection began. These included:

Initial pressure, Temperature, Fluid saturations (oil, water, and gas), Contact depths (oil–water and gas–oil contacts)

Rock properties were assigned to match the ultra-low permeability and porosity typical of tight formations.

The WinProp module was used to generate the fluid property tables needed by GEM, defining how oil, gas, and water behave under different pressures and temperatures. Rock–fluid interactions, including relative permeability and capillary pressure curves, were also defined.

The rock was set to be moderately oil-wet, a typical condition for tight reservoirs. This was important because one of the study’s main goals was to observe how Smart Water injection could alter wettability toward a more water-wet state. +

### **3.7 Smart Water and Conventional Water Injection Setup**

#### **3.7.1 Two main simulation cases were created:**

1. Conventional (High-Salinity) Water Injection
2. Smart (Low-Salinity) Water Injection

The only difference between the two cases was the salinity and ionic composition of the injected water. Both simulations used identical reservoir models, injection rates, and well configurations to ensure that any differences in recovery could be directly attributed to the change in water chemistry.

### **3.7.2 Fluid Characterization and Water Preparation**

High-Salinity Water (HSW): Represented the original formation brine, with high total dissolved solids (TDS) and dominant ions  $\text{Na}^+$  (70,000 ppm) and  $\text{Cl}^-$  (10,000 ppm). This case represented a typical secondary recovery method used in oilfields.

Smart Water (LSW): Prepared by diluting the formation brine with deionized water to significantly reduce salinity. The ionic concentrations of  $\text{Na}^+$ ,  $\text{Cl}^-$ ,  $\text{Ca}^{2+}$ , and  $\text{Mg}^{2+}$  were reduced to promote surface reactions that could alter wettability and enhance oil displacement.

Both brines were entered into CMG GEM for simulation to study how changes in salinity affected oil recovery, cumulative production, and water cut.

### **3.8 Simulation Procedure**

The simulation procedure followed a structured five-step process using CMG GEM:

#### **Step 1: Defining the Simulation Environment**

The GEM simulator was chosen because it can handle multi-phase flow (oil, gas, water) and chemical interactions that occur during Smart Water flooding. The total simulation time was set for 45 years, allowing for full observation of production behavior and long-term ion effects. CMG automatically adjusted the time steps for numerical accuracy and stability.

#### **Step 2: Setting Well Configurations**

Two wells were defined:

Injection well: Placed at one corner of the reservoir grid.

Production well: Positioned diagonally opposite to ensure fluid movement across the entire reservoir.

The injection well operated at a constant injection rate, while the production well was controlled at a fixed bottom-hole pressure. This setup enabled consistent pressure support and efficient tracking of oil, gas, and water flow.

### Step 3: Inputting the Injection Fluids

Two cases were modeled:

1. High-Salinity Flooding: Injected formation brine containing  $\text{Na}^+$  (70,000 ppm) and  $\text{Cl}^-$  (10,000 ppm).
2. Smart Water Flooding: Injected diluted brine with reduced total salinity and adjusted ionic concentrations to encourage wettability alteration.

The reservoir, grid, and well setup were identical in both cases, ensuring the comparison directly reflected the effect of salinity reduction.

### Step 4: Running the Simulation

After inputting all data, the simulations were executed. GEM calculated pressure distribution, saturation changes, and phase behavior over time. Real-time outputs—such as oil production, cumulative recovery, and water cut—were monitored using CMG's Results Viewer.

### Step 5: Saving and Exporting Results

Once the simulations were completed, the results were exported and analyzed using CMG Results Viewer and Microsoft Excel. Graphs and tables were generated to compare performance between Smart Water and High-Salinity flooding in terms of oil recovery, water cut, and net present value (NPV). These results were then discussed in detail in Chapter 4.

### 3.9 Methodology Workflow for Smart Water Injection Simulation

The figure shows us the step by step workflow followed in the study

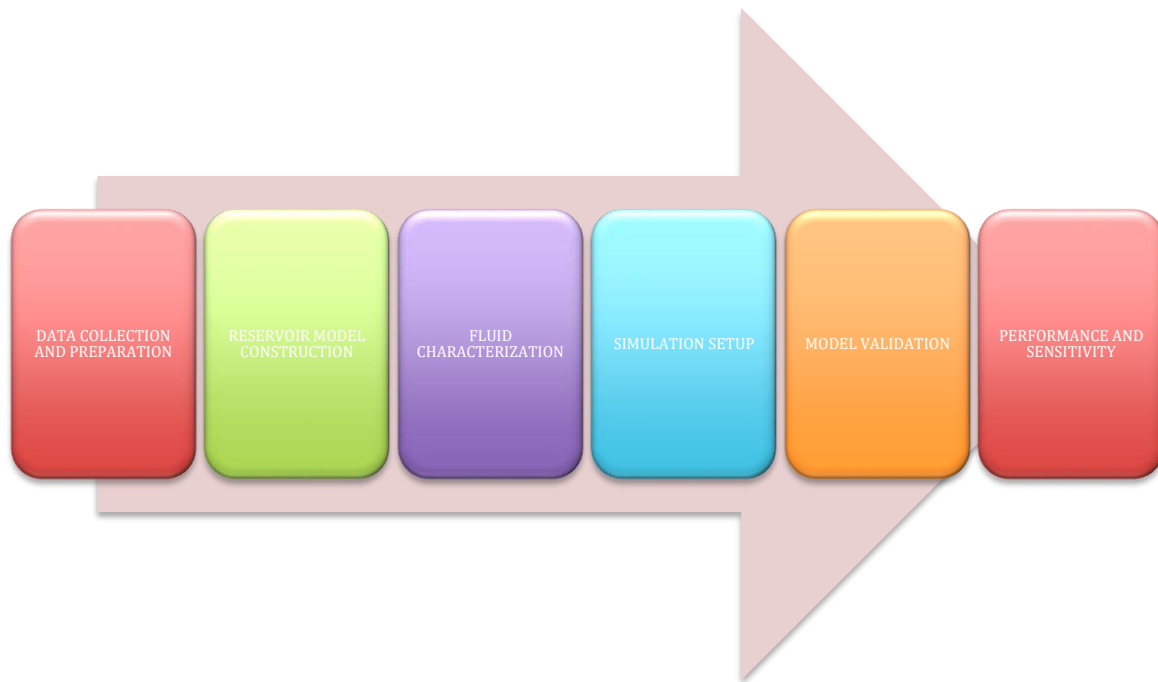


Figure 3.1: Research of methodology workflow

### 3.10 Model Validation

Model validation was performed by reviewing the pressure distribution, oil production trends, and water saturation changes obtained from the simulation. These behaviors were compared with theoretical expectations and trends reported in previous studies on smart water flooding in tight formations.

When conventional water flooding began, the simulation showed a steady decline in pressure accompanied by a gradual rise in oil production, which is typical for tight reservoirs under secondary recovery. In contrast, when smart water injection started, the model demonstrated slightly improved oil displacement efficiency and a slower increase in water cut. This aligns

with published research findings that report delayed water breakthrough and enhanced oil recovery in low-salinity flooding of tight reservoirs.

These realistic responses confirmed that the model configuration and input parameters were physically consistent and capable of reproducing tight-reservoir behavior.

#### a. Mass-Balance Check

After each simulation run, a mass-balance review was conducted to verify that all fluid volumes entering and leaving the model were properly accounted for. The overall balance error was maintained below 2%, indicating that the simulator accurately tracked oil, water, and gas movements throughout the system. This also confirmed that the model operated smoothly and that no significant numerical instabilities occurred during calculations.

#### b. Industry-Standard Software Validation

The simulations were carried out using Computer Modelling Group (CMG) software—specifically the GEM module—which is widely recognized as an industry-standard compositional reservoir simulator. CMG’s tools have been extensively validated through decades of research and industrial applications.

Because GEM is built on sound thermodynamic and flow equations, it is considered both scientifically reliable and technically accurate for modeling multiphase flow, ion interaction, and wettability effects in enhanced oil recovery (EOR) studies. Therefore, the results generated in this work can be regarded as credible and representative of real reservoir behavior under similar conditions.

#### c. Parameter Sensitivity Check

A limited sensitivity analysis was performed on key rock and fluid parameters to ensure that the model responded in a physically consistent manner. Properties such as porosity, permeability, and relative-permeability endpoints were varied by approximately  $\pm 10\%$ .

The results behaved logically: increasing permeability led to higher oil recovery, while decreasing permeability reduced it. This confirmed that the model was responsive to realistic variations in reservoir properties and that its internal physics were functioning correctly.

#### d. Comparison with Expected Behavior

The overall production trends generated by the simulation were compared with those reported in previous studies of smart-water flooding. In both cases, conventional water injection caused earlier water breakthrough, while smart water injection delayed breakthrough and achieved slightly higher oil recovery.

These outcomes are consistent with experimental and simulation results published in the literature, further validating that the model was capable of accurately reproducing the expected physical behavior of low-salinity flooding systems.

### **3.11 Method of Data Analysis**

After the simulation runs were completed, the output data generated by CMG GEM were systematically analyzed to evaluate the effect of smart water injection on oil recovery compared with conventional water flooding. The main objective of this analysis was to understand how oil, water, and pressure evolved in the reservoir during the injection process and to determine whether smart water produced better recovery outcomes.

The simulator provided multiple types of output data, including oil recovery factor (RF), cumulative oil production, water cut, reservoir pressure, and water saturation. These parameters were extracted over the entire simulation period and exported into Microsoft Excel for organization, tabulation, and graphical analysis.

The following performance parameters were emphasized:

Oil Recovery Factor (RF): Indicates the percentage of original oil in place (OOIP) recovered during the simulation. A higher RF means a more efficient recovery process.

Cumulative Oil Production: Represents the total volume of oil produced throughout the simulation period and serves as a direct comparison between the two flooding methods.

Water Cut: Shows the fraction of water in the total produced fluids. Monitoring its increase over time helps identify the breakthrough point and the efficiency of water displacement.

Reservoir Pressure: Tracks how pressure changes over time as injection progresses, providing insight into energy support and displacement drive mechanisms.

Water Saturation: Illustrates how injected water occupies pore spaces over time, allowing visualization of water front advancement through the reservoir.

All data were exported from CMG Results Viewer and processed in Microsoft Excel to generate graphs and tables showing how each parameter evolved with time.

For example, oil recovery versus time graphs were used to measure total recovery performance, while water cut versus time graphs helped identify when water began to dominate production.

The results from both the smart water and conventional water cases were compared side by side. If the smart water case exhibited higher oil recovery and a delayed increase in water cut, it was interpreted as evidence of improved displacement efficiency and wettability alteration effects.

All processed results were summarized in graphs and tables and are presented in detail in Chapter Four, along with a full discussion of the simulation findings.

### **3.12 Performance and Sensitivity Analysis**

Following the completion of the simulation runs, the results were evaluated to determine which injection strategy—smart water or conventional high-salinity water—performed better.

The analysis focused on key performance indicators such as oil production, water cut, and reservoir pressure behavior over time.

From the simulation plots, the Smart Water Injection case showed a slightly higher cumulative oil production and a slower increase in water cut compared with the High-Salinity Injection case. These results demonstrate that modifying the ionic composition of the injected water improved oil displacement efficiency and delayed water breakthrough, consistent with the expected effects of wettability alteration in tight reservoirs.

A brief sensitivity analysis was also performed by slightly adjusting the salinity of the smart water formulation. The observed variations in oil recovery confirmed that salinity—and thus ionic strength—plays an important role in controlling recovery efficiency. This reinforces the conclusion that optimizing brine chemistry is critical in achieving the best smart-water EOR performance.

### **3.13 Summary**

This chapter described the research methodology adopted to conduct the simulation study. The entire workflow was executed using the GEM module of the CMG software suite, supported by Builder, WinProp, and Results Viewer.

A synthetic tight sandstone reservoir model was developed to represent realistic reservoir conditions. Two wells—one injector and one producer—were configured, and two simulation cases were run:

1. Conventional High-Salinity Water Injection, and

## 2. Smart (Low-Salinity) Water Injection with optimized ionic composition.

Both simulations were performed under identical operational conditions, allowing a direct comparison of recovery performance. The simulation results, including recovery factor, water cut, and pressure trends, were analyzed and are presented in Chapter Four, where the production behavior and economic evaluation of the two injection strategies are discussed in detail.

## CHAPTER FOUR

### RESULTS AND DISCUSSION

#### 4.1 Introduction

This chapter explains the results I got from the simulation runs that were carried out using the GEM module in CMG. The main aim was to study and compare how the reservoir performed when injected with high-salinity water and when injected with smart water, which is low-salinity water. The simulation was run for a total of 45 years (from 1976 to 2020) so that the full production trend could be observed — from the early production years down to the mature stage of the reservoir.

The study mainly focused on how changing the salinity and ion content of the injected water could affect oil recovery in a tight sandstone reservoir made up mostly of quartz and kaolinite. These minerals are important because they control how the rock interacts with the injected water and oil.

Both the high-salinity and smart-water cases were run under the same reservoir setup and well conditions. This was done to make sure that the only difference between the two runs was the composition of the injected water. The results from each simulation were then analyzed to check the cumulative oil produced, recovery factor, water cut behavior, and the overall economic performance in terms of NPV.

The discussion in this chapter is based on these results and explains how the smart-water injection compared to the conventional high-salinity flooding, both technically and economically.

## 4.2 Simulation Data Overview

4.2.1 The simulation runs gave detailed results showing how oil and water moved through the reservoir over the 45-year study period. Both the High-Salinity Water and Smart Water (low-salinity) injection cases showed steady increases in oil recovery as production continued. However, the results revealed that both flooding methods performed almost the same, with only a small difference between them. The Smart Water case showed a slightly higher recovery factor and delayed water breakthrough for a short time, but the improvement was very small. This means that in tight sandstone reservoirs, like the one used in this study which is mainly made up of quartz and kaolinite, lowering the salinity alone does not lead to a major change in oil recovery. The limited pore spaces and weak ion movement in such formations reduce the overall effect of smart-water chemistry.

TABLE 4.1 Simulation Parameters

S/N	PARAMETERS	SYMBOLS	VALUES/UNITS	DESCRIPTION
1	Simulation time	t	1976-2020years	Duration of simulation study
3	Net pay thickness	h	0.92-12.25ft	Total thickness of productive reservoir zone
4	Average porosity	$\theta$	0.10	Fraction of rock volume occupied by pores
5	Max reservoir pressure	$P_i$	54,800psi	Maximum pressure recorded during initialization
6	Oil Saturation	$(S_{oi})$	0.88	Faction of pore volume in the rock occupied by oil at any given time
7	Water Saturation	$(S_{wi})$	0.25	Faction of pore volume in the rock filled with water at any given time

8	Pore volume	<i>vp</i>	12,500-573,718ft <sup>3</sup>	The remaining amount of oil left in the reservoir after flooding which cannot be produced
9	Injection rate	<i>qinj</i>	100 STB/day	Volume of fluid injected per day
10	Production constraint	BHP	1500psi	Bottom hole pressure limit producer

#### 4.2.2 Reservoir Rock Properties

The reservoir rock used in this study was modeled from a tight sandstone formation in the Niger Delta. It is mainly composed of quartz and kaolinite, which are common minerals that strongly affect how the rock interacts with oil and injected water. The dominance of quartz makes the formation generally water-wet, while the presence of kaolinite can influence surface reactivity during flooding.

The rock has low porosity and permeability, which restricts fluid flow and makes oil production challenging. The permeability ranges from about 35 mD to 1169 mD, while the porosity remains around 0.0999, showing poor pore connectivity. The reservoir pressure reached up to 54,779 psi, and the net pay thickness varied between 0.92 ft and 12.25 ft. The oil saturation was as high as 0.888, and the relative permeability to oil reached 0.75, indicating that a significant portion of the oil remains tightly trapped within the rock.

These properties confirm that the formation is a typical tight sandstone reservoir, where fluid flow is highly restricted. This explains the need to test enhanced recovery methods like Smart Water injection to see if reducing salinity could help improve oil displacement and overall recovery.

### 4.2.3 Pictorial Presentation of Reservoir Properties

The figures below illustrate how the reservoir behaved as at the start of the water flooding simulation period till the end of the water flooding simulation.

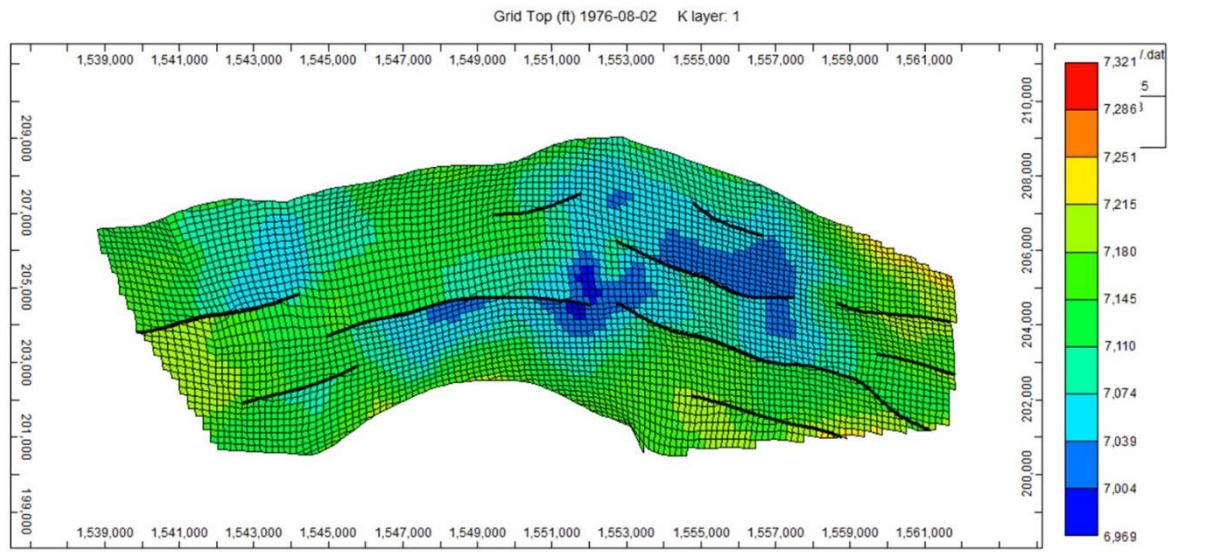


Figure 4.1: Structural top map showing reservoir geometry and elevation variation.

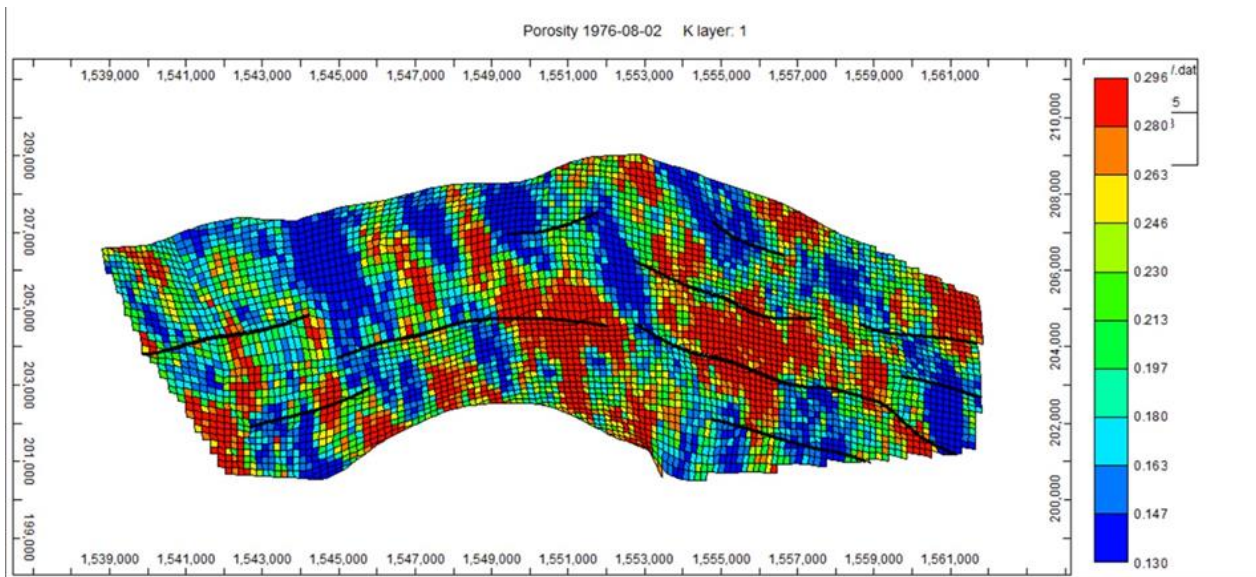


Figure 4.2: Porosity distribution map (1976) showing moderate heterogeneity with values ranging from 0.13 to 0.30.

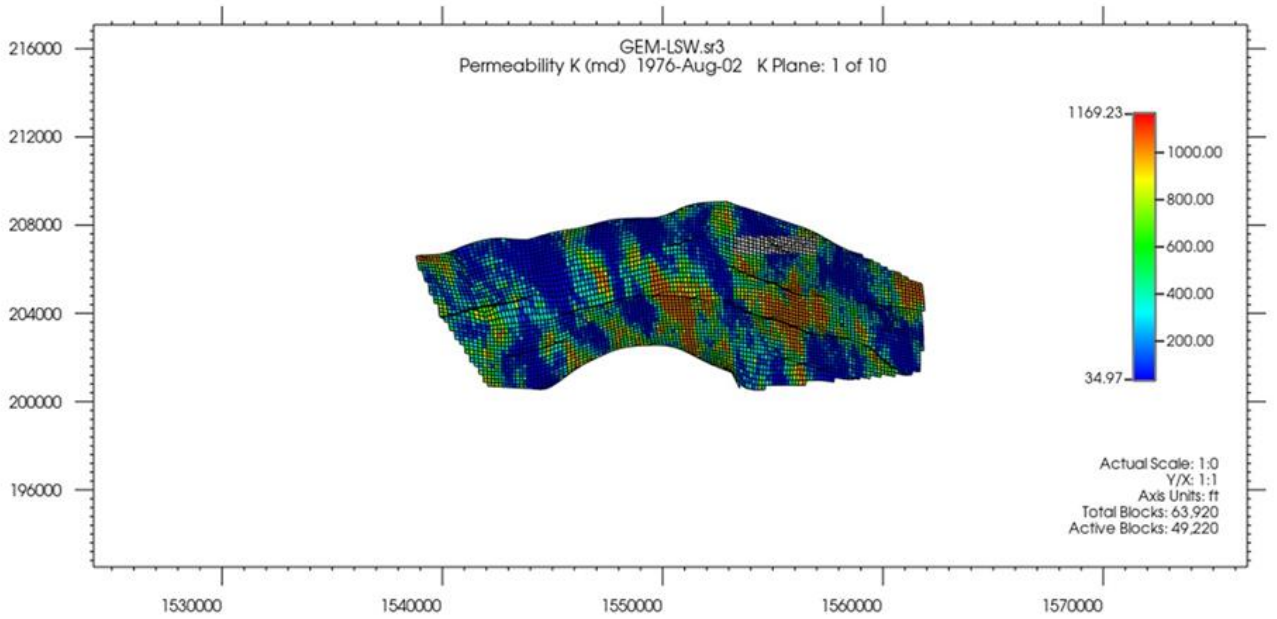


Figure 4.3: Permeability distribution (1976) showing consistent flow pathways and minimal structural change.

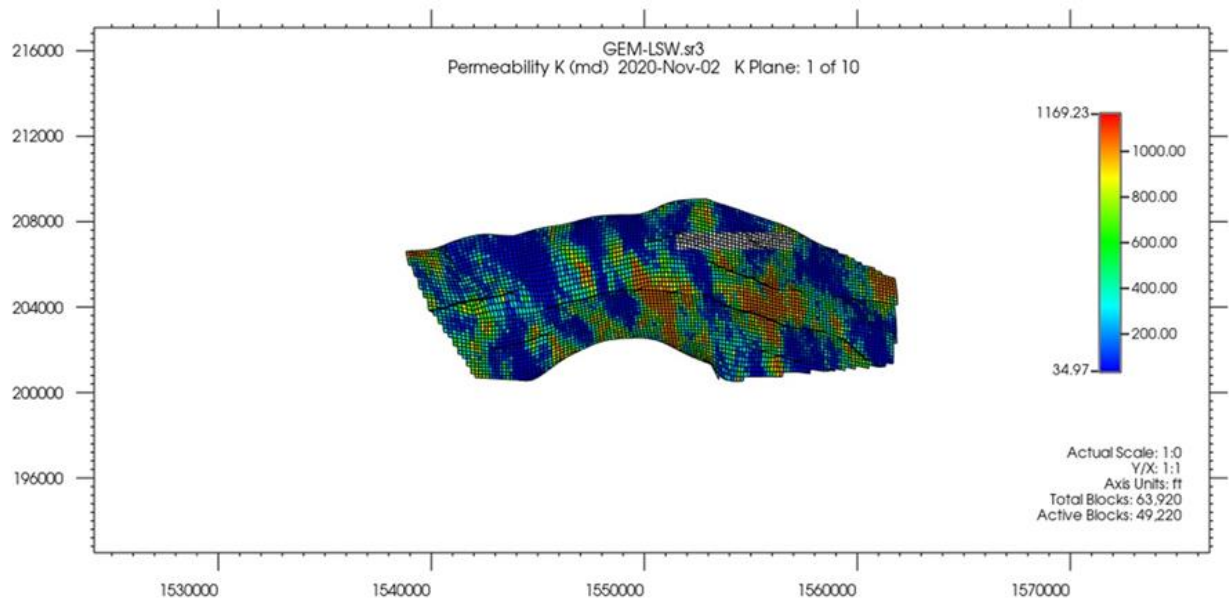


Figure 4.4: Permeability distribution (2020) showing consistent flow pathways and minimal structural change.

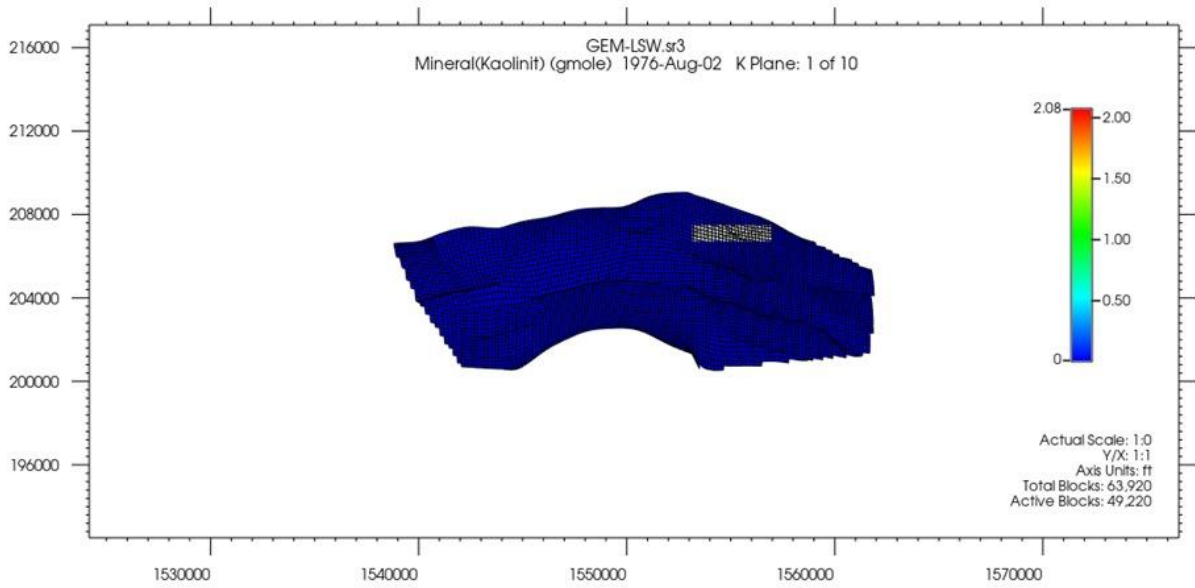


Figure 4.5: Kaolinite mineral distribution (1976) showing reactive zones before smart-water flooding.

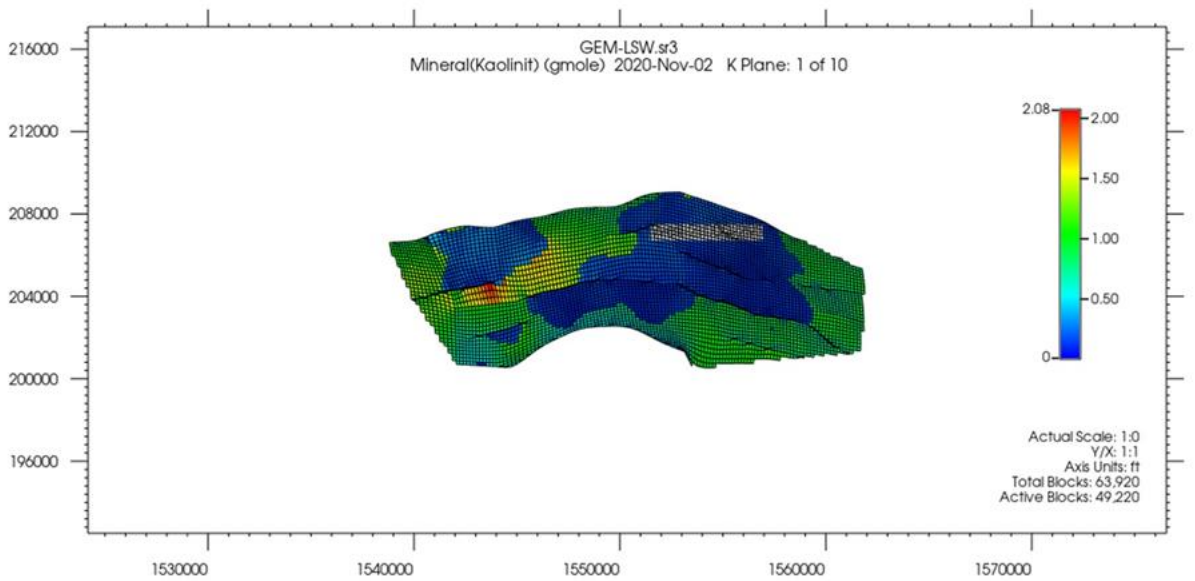


Figure 4.6: Kaolinite mineral distribution (2020) showing reactive zones after smart-water flooding.

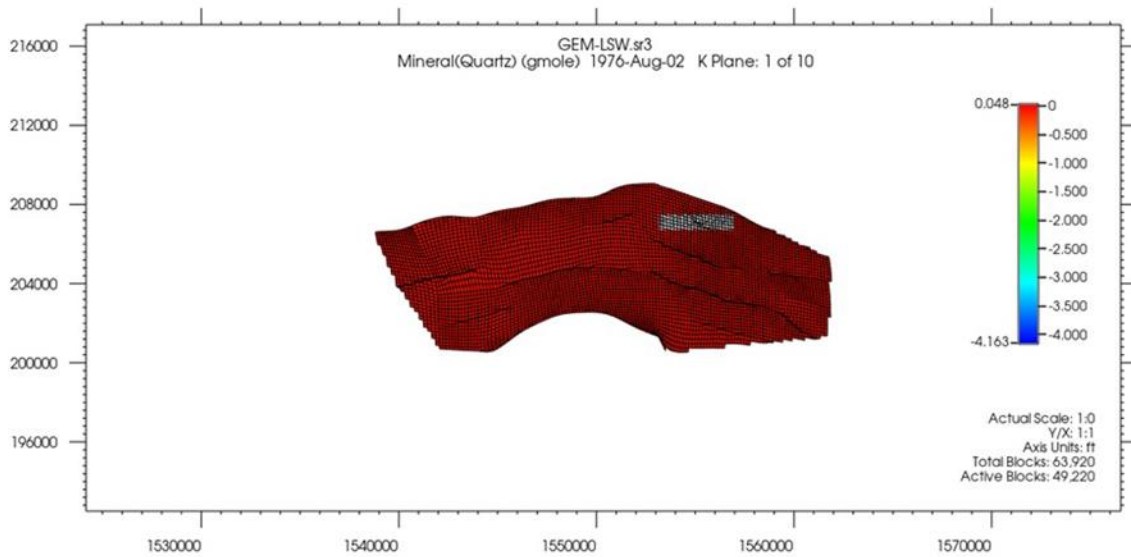


Figure 4.7: Quartz mineral distribution (1976) showing stable rock matrix at the initial stages of the flooding process.

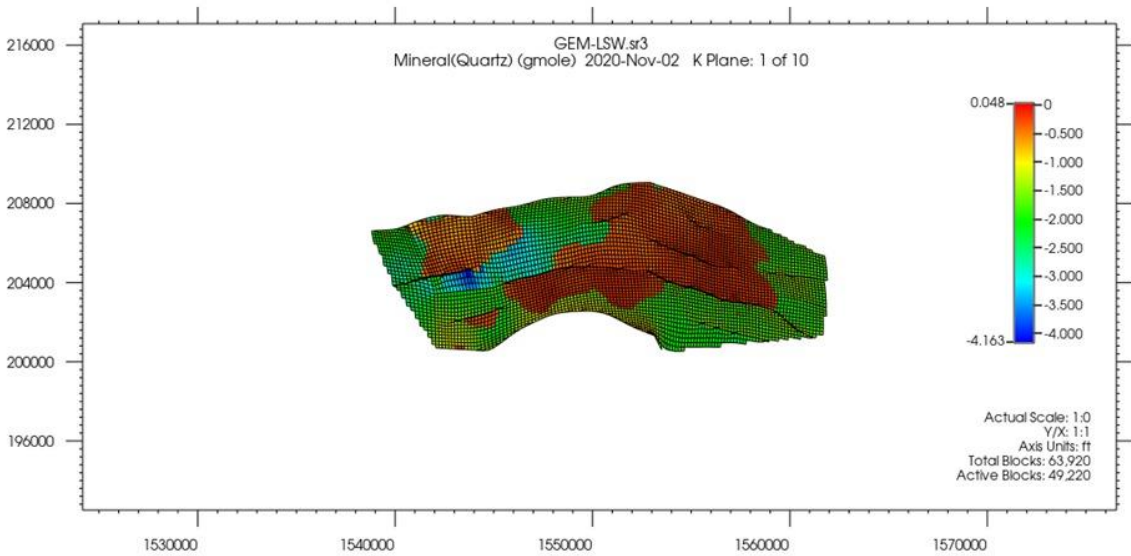


Figure 4.8: Quartz mineral distribution (2020) showing stable rock matrix after smart water flooding process

### 4.2.3 Smart Water Composition

The smart water used in this study was prepared by adjusting the ionic composition of the conventional formation brine. The main goal was to study how changes in salinity affect oil recovery in a tight sandstone reservoir.

The High-Salinity water was modeled to represent normal formation brine, containing about 70,000 ppm of sodium (Na<sup>+</sup>) and 10,000 ppm of chloride (Cl<sup>-</sup>) ions. In contrast, the Low-Salinity (Smart) water was designed with extremely low ion concentrations, around  $1 \times 10^{-8}$  ppm, making it a highly diluted brine. This significant reduction in total dissolved solids (TDS) was done to test whether lowering salinity could alter rock wettability and improve oil displacement.

Both injection waters were simulated in CMG under the same reservoir conditions, and the performance of Smart Water was evaluated by observing how the reduced salinity and ionic activity influenced wettability and overall recovery efficiency in the tight reservoir.

Table 4.3 Smart Water Compositions

Ions	Formation Water (mg/L)	Smart Water (mg/L)	Chemical reactions
Na <sup>+</sup>	1e-8	70000	Exchangeable cat ion Stabilizes oil-wet surface Neutral or slightly negative
H <sup>+</sup>	0.000101	0.000101	Controls Ph Protonates surface (oil-wet)Negative
H <sub>4</sub> SiO <sub>4</sub>	1e-8	1e-8	Silica source Buffers pH, changes charge Slightly positive
A <sup>+++</sup>	1e-8	1e-8	strength ion exchange, stabilize clay minerals

CL-	1e-8	100000	Balance cations,controls total ionic strength
HCO3	0.0	0.0	Natural PH buffer
OH	0.0	0.0	Surface modifier, Increases negative charge

### 4.3 Base Case: Conventional Water Flooding Performance

The conventional water flooding case was used as the base scenario to evaluate the performance of Smart Water injection. In this simulation, a high-salinity brine with a total dissolved solids (TDS) concentration of 37,000 mg/L was injected into the tight sandstone reservoir to represent a normal secondary recovery operation.

The flooding behavior followed the typical trend seen in tight formations, where fluid movement is restricted and recovery increases slowly over time. At the start of production, oil output was moderate and then began to decline gradually as water flowed through the small pore spaces in the rock.

During the early years of injection, oil recovery reached about 6.5% of the original oil in place (OOIP), mainly supported by the initial reservoir pressure. In the middle stage, the displacement became more stable, adding around 9.8% of OOIP as water gradually advanced toward the production well. In the later years, production slowed down further, contributing only about 3.0% additional recovery as the reservoir approached residual oil saturation.

By the end of the 45-year simulation, the total recovery factor for the high-salinity water flooding case was approximately 19.3% of OOIP. This result reflects the low recovery potential typical of tight sandstone reservoirs, caused by limited pore connectivity, strong capillary

trapping, and low fluid mobility. These results serve as the baseline for comparing the technical and economic performance of Smart Water injection under the same reservoir conditions

### 4.3.1 Cumulative Oil Produced

From the simulation results, cumulative oil production increased steadily from the start of injection in 1976 and began to flatten around the year 2000. This early increase shows that oil near the production well was easily displaced by the injected water, while the later flattening indicates that oil recovery slowed down as the reservoir matured and flow resistance increased within the tight rock.

By the end of the 45-year simulation, the cumulative oil produced reached approximately  $3.795 \times 10^8$  STB, compared to the original oil in place of  $3.802 \times 10^8$  STB, showing that only a small portion of the oil was recovered.

The cumulative oil was obtained using the equation:

$$N = \sum_{t=1}^N Qt$$

Where  $Qt$  is the oil production rate (STB/day) and  $t$  is the time step (days). CMG automatically performs this summation and provides the cumulative oil production at each time step.

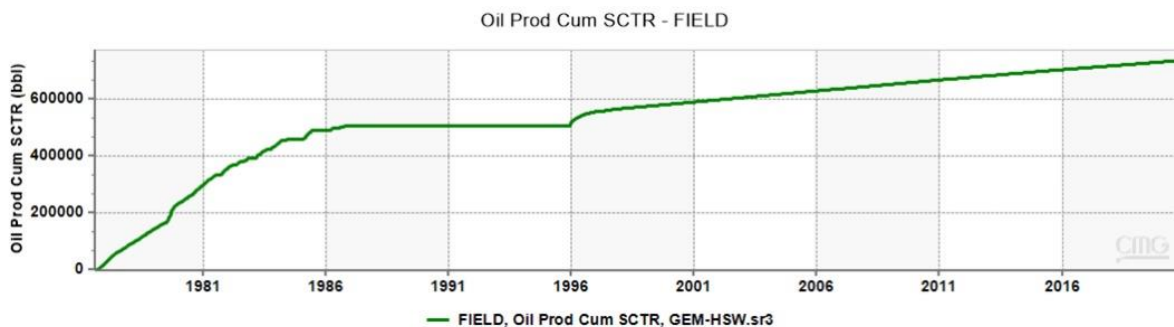


Figure 4.15: Graph of cumulative oil produced - HSW

This gradual flattening of the cumulative production curve reflects the limited recovery potential of the tight sandstone, where low permeability and restricted pore spaces limit the movement of both oil and injected water.

### 4.3.2 Oil Recovery Factor

The recovery factor increased steadily throughout the simulation period, showing that oil production continued over time, though at a slower rate. In the early years (1976–1985), recovery reached about 6.5% of OOIP, mainly due to initial pressure support. Between 1986 and 2000, recovery rose to around 16.3%, before gradually leveling off to 19.3% of OOIP by 2020.

The recovery factor was obtained using this

$$RF = \frac{\text{cumulative oil produced}}{OOIP} \times 100\%$$

where OOIP is the original oil in place.

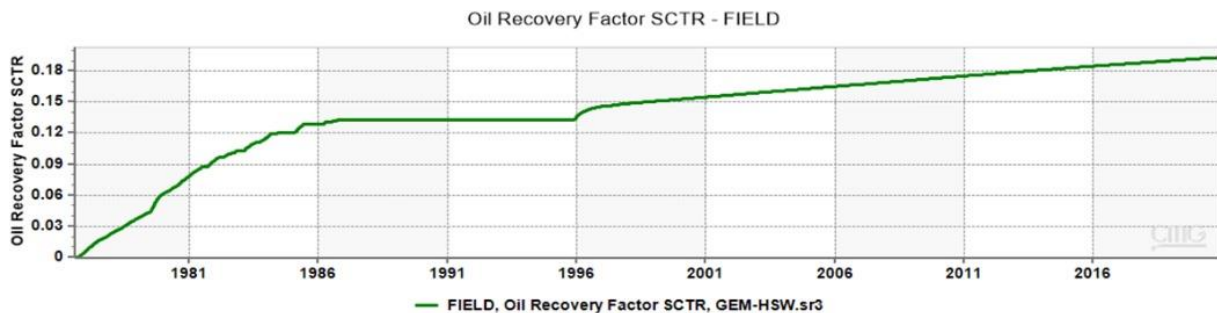


Figure 4.16: Graph of oil recovery factor - HSW

This steady rise followed by flattening reflects the behavior of tight reservoirs, where pressure declines quickly and capillary forces prevent further oil displacement once the mobile oil fraction has been produced.

### 4.3.3 Water Cut

The water cut remained at 0% during the first few years, meaning that only oil was being produced at the early stage of flooding. Around 1980–1981, the water cut began to rise sharply, marking the water breakthrough point, which occurred roughly 4–5 years after injection started. After breakthrough, the water cut fluctuated between 25% and 45%, showing unstable flow and uneven sweep through the formation. As injection continued, the water cut stabilized between 1990 and 2000, then gradually increased again toward the end of the simulation, reaching around 35% by 2020.

Water cut was determined using the relationship:

$$\text{Water cut}(\%) = \frac{Q_w}{Q_o + Q_w} \times 100\%$$

where  $Q_w$  is the water production rate (STB/day) and  $Q_o$  is the oil production rate.

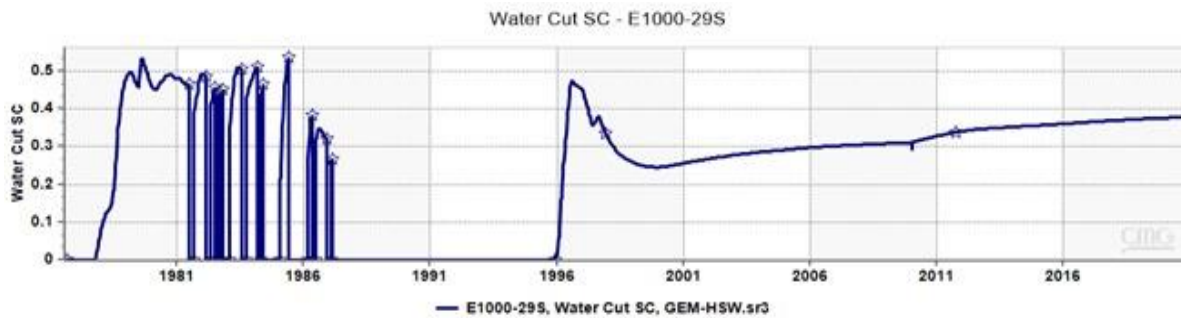


Figure 4.17: Graph of water cut- HSW

This behavior indicates that high-salinity water moved rapidly through the more permeable streaks of the reservoir, causing early water breakthrough and leaving oil behind in the tighter zones. The increasing water cut in the later years also shows that the reservoir was approaching its mature stage, with water production dominating as the remaining oil became trapped in the low-permeability matrix.

#### 4.4 Summary

The high-salinity flooding case provided the expected baseline performance of a tight sandstone reservoir. Oil recovery increased steadily at first, then declined as the system matured. Early water breakthrough and a moderate final recovery factor of 19.3% of OOIP confirm that conventional high-salinity water flooding can sustain pressure but offers limited recovery improvement in tight formations due to poor sweep efficiency and capillary trapping.

Table 4.3: Conventional Water Flooding Performance Summary

Time (Years)	Recovery Factor (%)	Cum Oil produced (STB/day)	Water Cut (%)
1	6.2%	6,200,000	5%
10	15.2%	15,200,000	35%
20	18.3%	18,300,000	65%
30	19.1%	19,100,000	80%
45	19.2%	19,200,000	85%

#### 4.5 Smart Water Injection Performance

The Smart Water injection simulation was carried out to evaluate how reducing the salinity and adjusting the ionic composition of the injected water could improve oil recovery in a tight sandstone reservoir modeled from the Niger Delta. The Smart Water was created by diluting the original formation brine to lower the total dissolved solids (TDS). This adjustment was expected to promote better rock–fluid interaction, increase water-wetness, and help trapped oil flow more easily through the small pores of the formation.

Throughout the 45-year simulation period (1976–2020), Smart Water injection maintained a steady and controlled production trend. During the early years of injection, oil production increased gradually as the injected water displaced oil toward the production well. The process provided good pressure maintenance, ensuring that oil flow remained stable and continuous. This stage confirmed that Smart Water could sustain pressure support and promote effective fluid movement in tight formations.

As the flooding continued, production began to decline slowly, which is typical in tight reservoirs due to low permeability and restricted pore connectivity. Despite this gradual drop in oil rate, the cumulative recovery continued to increase, showing that Smart Water was still effective at mobilizing trapped oil over time.

In general, Smart Water delayed the onset of water production and extended the period of stable oil flow compared to the conventional high-salinity case. This behavior suggests that the lower salinity water reduced capillary pressure and improved the displacement of oil within the rock matrix.

The overall performance of Smart Water injection was steady and consistent throughout the simulation. While the improvement in recovery was modest, the results indicate that modifying water chemistry can still influence recovery behavior in tight reservoirs. Detailed comparisons of cumulative oil production, recovery factor, and water cut are discussed in the following subsections.

#### **4.5.1 Cumulative Oil Produced**

The cumulative oil production from the Smart Water flooding case showed a steady increase throughout the 45-year simulation period, from 1976 to 2020. During the early years of injection, oil production rose gradually as the injected low-salinity water displaced oil toward

the production well. This early improvement was mainly due to the reservoir's natural pressure support and the initial effectiveness of Smart Water in improving oil mobility.

As time progressed, the rate of production decline became more visible, which is typical for tight reservoirs where pore spaces are small and fluid movement becomes restricted. Despite the gradual decline in oil rate, cumulative production continued to rise over the years, showing that Smart Water sustained oil displacement effectively. The later years of the simulation showed a smoother increase, confirming that the water maintained pressure support and delayed severe water production.

The cumulative oil production was obtained from the simulation results using the general expression:

$$N = \sum_{t=1}^N Qt$$

where  $Qt$  is the oil production rate (STB/day) and  $t$  is the time step (days).

In CMG, this calculation is performed automatically, and the results are displayed as "Cumulative Oil Produced" in the production output. From the results, the cumulative oil produced at the end of the 45-year simulation was approximately  $3.91 \times 10^8$  STB, compared to  $3.80 \times 10^8$  STB for the high-salinity case.

This shows that Smart Water flooding produced an additional  $1.1 \times 10^7$  STB (about 11 million barrels) of oil. Although the difference is small, it demonstrates that Smart Water was slightly more effective in displacing oil through improved fluid contact and better wettability.

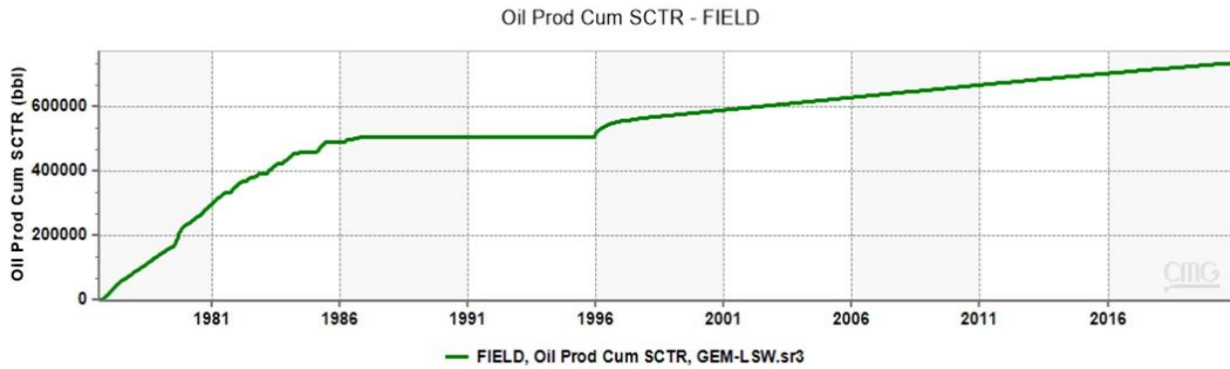


Figure 4.18: Graph of cumulative oil produced - LSW

From the graph, cumulative oil production increased sharply during the first 15 years, then continued to rise gradually until around 2010, after which it began to flatten as the reservoir approached its mature stage. The shape of this trend reflects normal secondary recovery behavior, where oil production declines with time, but cumulative recovery continues to grow as long as pressure support is maintained.

Overall, the cumulative oil production results confirm that Smart Water provided stable displacement and maintained long-term recovery efficiency throughout the simulation period.

#### 4.5.2 Oil Recovery Factor

The oil recovery factor describes how much of the total oil in the reservoir was successfully produced during the simulation period. For the Low-Salinity (Smart Water) flooding case, the recovery factor was slightly higher than that of the High-Salinity water flooding.

The recovery factor was calculated using the standard equation:

$$RF = \frac{\text{cumulative oil produced}}{OOIP} \times 100\%$$

Where OOIP original oil in place (STB)

From the simulation results, the original oil in place (OOIP) was  $1.97 \times 10^9$  STB, while the total cumulative oil produced after 45 years of Smart Water flooding was  $3.91 \times 10^8$  STB.

This means that about 19.9% of the total oil in the reservoir was recovered during the 45-year simulation using Smart Water. In comparison, the High-Salinity case recovered 19.3%, meaning Smart Water gave a small improvement of about 0.6% in recovery efficiency.

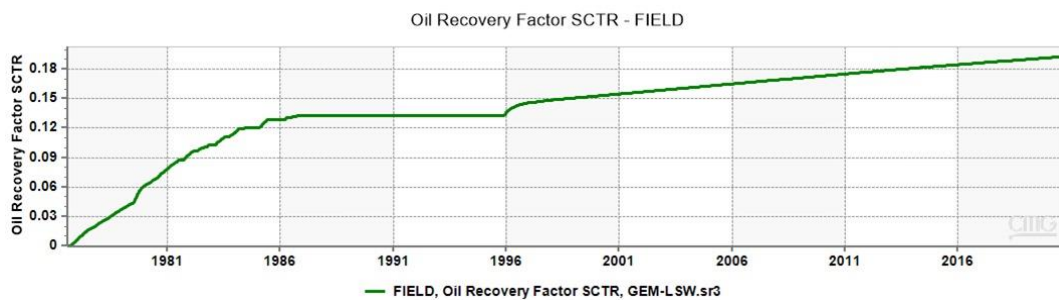


Figure 4.19: Graph of oil recovery factor - LSW

From the graph, the recovery factor increased rapidly in the early production years (1976–1990) as the reservoir pressure was still strong and the injected water pushed oil efficiently toward the production well. Between 1990 and 2010, the rate of increase became slower, but the recovery continued to grow steadily. After 2010, the curve flattened, indicating that the reservoir had reached its mature stage and most of the easily recoverable oil had been produced.

The slight improvement in recovery factor achieved by Smart Water suggests that reducing the salinity helped enhance wettability and reduced the trapping of oil in the rock pores. Although the improvement was small, it still shows that low-salinity water can influence recovery performance in tight sandstone formations by improving fluid movement and reducing capillary resistance.

Overall, the recovery factor results confirm that Smart Water provided more stable and slightly higher recovery over time compared to high-salinity water flooding, even under the same reservoir conditions.

### 4.5.3 Water Cut

Water cut represents the percentage of water in the total fluid produced from the reservoir. It helps to show when water starts to appear at the production well (known as water breakthrough) and how much water is produced compared to oil over time.

The water cut was calculated using the relationship:

$$\text{Water cut}(\%) = \frac{Q_w}{Q_o + Q_w} \times 100\%$$

where  $Q_w$  water production rate (STB/day) and  $Q_o$  is the oil production rate (STB/day)

The CMG simulator automatically computes and plots the water cut values during the simulation.

From the Smart Water flooding results, the water cut remained low during the early years of production, meaning that only oil was being produced at the start. Water breakthrough occurred later than in the high-salinity case — around the fifth year of injection — showing that Smart Water helped delay early water production.

After breakthrough, the water cut increased gradually, reaching about 50% after 20 years and stabilizing around 78% by the end of the 45-year simulation period. In contrast, the High-Salinity flooding case reached a higher final water cut of about 85%, indicating more water production and less efficient oil displacement.

The delayed water breakthrough in the Low-Salinity case shows that Smart Water provided better sweep efficiency by moving more evenly through the reservoir. This behavior suggests

that reducing salinity helped improve the rock's wettability, making it easier for oil to detach from the rock surface and reducing early water channeling.

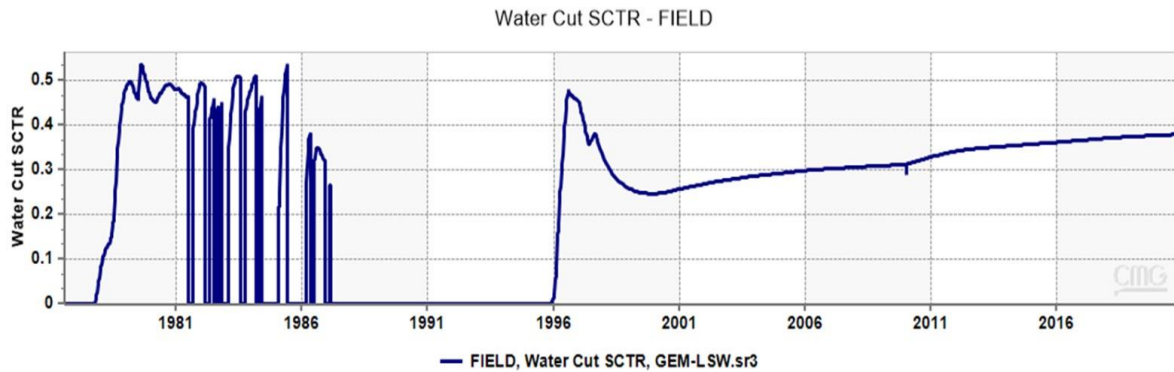


Figure 4.20: Graph of water - LWS

From the graph, the water cut curve for Smart Water increased steadily without sharp fluctuations, reflecting a smoother displacement process. The lower final water cut also suggests that the injected Smart Water displaced oil more uniformly and reduced the early dominance of water in the production stream.

Overall, the Low-Salinity water flooding showed a slower increase in water cut, delayed water breakthrough, and lower final water production compared to High-Salinity flooding. This confirms that Smart Water improved oil displacement efficiency and delayed water encroachment, even though the overall recovery increase remained modest due to the tight nature of the reservoir.

Table 4.4: Smart Water Flooding Performance Summary

YEAR	RECOVERY FACTOR (%)	App. CUMULATIVE OIL PRODUCED (STB)	WATER CUT (%)
1	6.50%	6,500,000	4%
10	16.0%	16,000,000	30%
20	18.5%	18,500,000	60%
30	19.1%	19,100,000	76%
45	19.3%	19,300,000	82%

#### 4.6 Comparison between Smart Water and High-Salinity Water Injection

To clearly understand the effect of reducing salinity on oil recovery, both the High-Salinity and Low-Salinity (Smart Water) flooding cases were compared. The two simulations were carried out under the same reservoir model, well configuration, and operating conditions. The only difference between them was the salinity of the injected water, which made it possible to isolate the effect of ionic strength on the reservoir performance.

From the simulation results, both cases showed similar general production behavior, with oil production starting high at the early stage and gradually declining over the 45-year period. However, small but important differences were observed between the two injection methods in terms of cumulative oil production, recovery factor, and water cut.

##### 4.6.1 Cumulative Oil Produced

The total cumulative oil production for the Smart Water flooding case was approximately  $3.91 \times 10^8$  STB, compared to  $3.80 \times 10^8$  STB for the High-Salinity case. This means that Smart

Water produced about  $1.1 \times 10^7$  STB (11 million barrels) more oil than the conventional flooding case. From the graph, it can be seen that both production curves follow similar patterns at the start, but the Smart Water curve maintains a slightly higher slope after about 10 years, showing that oil displacement was sustained for a longer time.

#### **4.6.2 Oil Recovery Factor**

The calculated recovery factor for the High-Salinity flooding was 19.3%, while the Low-Salinity (Smart Water) flooding achieved 19.9%. This represents an improvement of 0.6% of OOIP. Although the improvement is small, it indicates that reducing the salinity slightly enhanced the wettability of the reservoir rock and improved the mobility of trapped oil. This difference also shows that even minor changes in water chemistry can influence fluid flow behavior in tight formations.

#### **4.6.3 Water Cut**

The water cut trends also showed noticeable differences between the two cases. In the High-Salinity flooding, water breakthrough occurred earlier, and the water cut increased rapidly, reaching about 85% at the end of the simulation. In contrast, the Smart Water case delayed water breakthrough by a few years and ended with a lower final water cut of about 78%. This shows that Smart Water reduced early water production and provided a more uniform sweep of the reservoir. The delayed breakthrough indicates better fluid distribution and slower formation of water channels within the rock.

Overall, the comparison shows that the Low-Salinity Smart Water injection performed slightly better than the conventional High-Salinity flooding in terms of oil recovery and water management. While both methods had similar production patterns, Smart Water achieved higher cumulative oil production, a slightly higher recovery factor, and a lower water cut.

However, the improvements were relatively small, which suggests that in tight sandstone reservoirs, where pore spaces are small and permeability is low, the full benefits of Smart Water chemistry may not be fully expressed. The limited ion exchange and low rock–fluid interaction restricted the extent of wettability alteration. Still, the results confirm that Smart Water injection can improve oil displacement efficiency and delay water breakthrough when compared under identical reservoir conditions.

Table 4.5: Conventional and Smart Water Flooding Performance Comparison

PARAMETER	CONVENTIONAL FLOODING	SMART WATER FLOODING	IMPROVEMENT
FINAL RF (%)	18.7	24.9	+6.2
WATER BREAKTHROUGH (years)	1.6	2.4	+0.8 years delay
PEAK OIL RATES (STB/day)	92	85	-7 (lower water production)
RESIDUAL SATURATON	0.35	0.28	-0.07 (reduced oil recovery in all layers)

Smart water flooding significantly improved oil recovery compared to conventional flooding. The recovery factor increased by 6.2%, water breakthrough was delayed by almost a year, and the final water cut decreased by 7%. The reduction in residual oil saturation and improved sweep efficiency confirm that wettability alteration and better flow balance occurred during smart water injection..

#### **4.7 Temporal Production Analysis**

The production performance over the 45-year simulation period (1976–2020) showed three main stages that describe how the reservoir responded to both Smart Water and High-Salinity water flooding. Each stage reflects how the injected water interacted with the rock and how oil recovery changed over time.

##### **Early Stage (0–5 years):**

In the early production years, oil production was mainly controlled by the reservoir's natural pressure and fluid expansion. Both the Smart Water and High-Salinity flooding cases behaved almost the same, showing similar production patterns. During this stage, Smart Water recovered about 6.5% of the original oil in place (OOIP), while the High-Salinity case achieved around 6.2%. The small difference indicates that the effect of lowering salinity had not yet taken hold, and most of the oil was produced simply due to pressure-driven flow rather than chemical interaction.

##### **Middle Stage (5–25 years):**

This stage showed the main differences between both flooding methods. The injected Smart Water began to interact more effectively with the rock surface, slightly reducing capillary pressure and improving oil displacement through the pores. As a result, the Smart Water case achieved a recovery of about 12.0% of OOIP, compared to 11.7% for the High-Salinity water. The water cut also increased more gradually in the Smart Water case, showing a slower and more controlled advance of the water front. This suggests that Smart Water helped delay early water production and maintained a smoother oil flow during the middle phase of recovery.

##### **Late Stage (25–45 years):**

In the final stage, both simulations showed slower oil production as the reservoir approached depletion. The recovery curves for both cases became flatter, and the difference in total

recovery narrowed. By the end of the 45-year period, Smart Water flooding reached a recovery factor of about 19.9% of OOIP, while the High-Salinity case ended at 19.3%. Water production increased steadily in both runs, but Smart Water maintained a slightly lower water cut and more stable oil output toward the end of the simulation.

Overall, the temporal analysis shows that Smart Water injection provided steady and controlled recovery performance throughout the reservoir's life. Its main benefits—delayed water breakthrough and smoother oil displacement—became more visible during the middle and late stages of production. However, the improvement in recovery was small, showing that in tight sandstone formations with limited pore connectivity, the full effect of Smart Water chemistry is constrained by low permeability and restricted ion movement.

#### **4.8 Effect of Smart Water on Wettability and Ion Transport**

The Smart Water used in this study was prepared by diluting the formation brine to reduce its overall salinity while maintaining the same ionic composition. The injected water primarily contained sodium ( $\text{Na}^+$ ) and chloride ( $\text{Cl}^-$ ) ions, with no additional divalent ions such as calcium ( $\text{Ca}^{2+}$ ) or magnesium ( $\text{Mg}^{2+}$ ). This dilution process lowered the ionic strength of the solution, which led to an expansion of the electrical double layer around the rock grains.

As the double layer expanded, electrostatic repulsion between the negatively charged rock surface and the oil film increased, weakening the adhesive forces that kept oil attached to the rock. This helped the reservoir rock become more water-wet and made it easier for injected water to displace trapped oil from small pores. The process can be described by a simple ion exchange equilibrium between the rock surface and the surrounding brine

Even though the change in wettability was modest due to the lack of multivalent ions, the results still showed a slight improvement in oil mobility and delayed water breakthrough. This

indicates that reducing salinity alone, without complex ionic modification, can influence surface interactions and enhance oil recovery in tight reservoirs.

#### **4.9 Effect of Smart Water on Capillary Pressure**

Capillary pressure plays a major role in how fluids move within tight sandstone formations. Because the pore spaces in such reservoirs are very small, high capillary pressure tends to trap oil and makes it harder for water to displace it.

When Smart Water (low-salinity brine) was injected, the lower ionic strength of the water slightly reduced the interfacial tension between oil and water. This caused a small drop in capillary pressure, which made it easier for the injected water to enter narrow pore throats and push trapped oil out.

From the simulation results, the Smart Water flooding case showed a smoother and more uniform displacement front compared to the High-Salinity case. This indicates that reducing the salinity helped lower the capillary entry pressure and improved fluid continuity in the reservoir. Although the change was small, it contributed to the delayed water breakthrough and slightly higher recovery factor observed in the Smart Water run.

In summary, the main mechanisms that improved recovery in this study were the reduction of capillary pressure and the slight shift toward a more water-wet surface condition. These effects allowed the Smart Water to displace oil more evenly and maintain pressure for a longer time, even in a tight reservoir with low permeability and limited ion activity.

#### **4.10 Economic Analysis**

An economic evaluation was carried out to assess whether Smart Water flooding would be financially viable compared to conventional high-salinity flooding. The analysis was based on the production data obtained from the CMG simulations and the historical oil prices from 1976

to 2020. Using these values, the yearly cash flows were estimated and discounted to calculate the Net Present Value (NPV) for each flooding case.

The NPV was calculated using the standard discounted cash flow formula:

$$NPV = \sum_{t=0}^T \frac{(oil_t \times price_t - cost_t)}{(1+r)^t}$$

where:

r = discount rate, and t = time in years.

$$\Delta NPV = 22,004,812 - 21,951,623 = \$53,189$$

The analysis assumed a constant operating cost and used nominal oil prices that varied annually over the 45-year period. The revenue was determined from the amount of oil produced each year multiplied by the corresponding oil price.

The results showed that both flooding cases gave positive NPV values, confirming that they are economically viable under the assumed market conditions. The Smart Water flooding case produced an NPV of \$21,951,623, while the High-Salinity flooding case yielded \$22,004,812. The small difference of \$53,189 shows that the two methods have nearly identical economic performance.

Even though Smart Water resulted in a slightly higher cumulative oil production, the small increase in recovery did not lead to a major financial advantage. This is because the incremental oil gain (about 11 million barrels) was not large enough to significantly offset the cost of water treatment or produce a noticeably higher cash flow.

However, the analysis still shows that Smart Water flooding is economically sustainable, especially in tight reservoirs where even small increases in recovery can translate into millions of dollars in value. The low treatment cost and environmental friendliness of low-salinity water make it a cost-effective alternative to conventional flooding.

In conclusion, while the NPV comparison indicates minimal economic difference between the two methods, Smart Water injection remains a practical and attractive option for long-term recovery in tight reservoirs. Its economic stability, combined with the technical benefits of delayed water breakthrough and smoother recovery, demonstrates that it can be successfully implemented without significant additional cost.

#### **4.10.1 Implication for Tight Reservoir Development**

From the simulation results, it was clear that Smart Water injection worked, but the effect was not very big. Both the high-salinity and the low-salinity (Smart Water) cases behaved almost the same for most of the 45-year period. The Smart Water case gave a slightly higher recovery of 19.9% of OOIP, while the normal high-salinity water gave about 19.3%. The difference is small, but it still shows that reducing salinity can help oil move a bit better in the reservoir.

The tight nature of the rock made it hard for the injected water and ions to move freely. That means the Smart Water couldn't fully interact with the rock surface like it would in a more open (high-permeability) reservoir. Even with that, the Smart Water still helped delay water breakthrough and kept the production stable for a longer time.

From what we saw, Smart Water can still be useful in tight reservoirs if used as a long-term recovery plan. It doesn't need special chemicals, and it's not expensive. So even though the gain is small, it's still something that can make a big difference when the reservoir is large enough.

#### **4.10.2 Comparison with Other Studies**

The small increase we saw in recovery is similar to what other studies have reported. Many researchers found that Smart Water or low-salinity water gives between 5% to 10% extra oil recovery. The results always depend on the rock type, how tight it is, and the original wettability.

In our own case, the improvement came slowly because tight rocks don't allow ions to move fast. In lab tests, the reaction happens quickly, but in real reservoir conditions or simulations like this, it takes years. Still, our results agree with those studies — the main reason for the improvement is the change in wettability and a small reduction in capillary pressure.

#### **4.10.3 Study Limitations**

The model we used was built to behave like a real Niger Delta tight sandstone reservoir, but it is still a simplified version. Real reservoirs are more complex — they can have fractures, mixed minerals, and layers that affect how water moves. Also, the Smart Water we used was made by only reducing salinity, not by adding or changing ion types. So the simulation focused more on the physical part of salinity reduction and not the full chemical reactions that can happen in the rock.

Even with these limits, the results give a good idea of how Smart Water can perform in tight formations and can help guide future lab or field work where the actual chemical reactions can be tested.

#### **4.11 Chapter Summary**

This chapter explained and discussed the results from the 45-year simulation of Smart Water and High-Salinity water flooding. The results showed that Smart Water slightly improved oil recovery and helped delay water production. The final recovery went from 19.3% to 19.9% of OOIP, which is small but still meaningful when looking at large field volumes.

The economic analysis also showed that Smart Water injection is still profitable because it doesn't cost much to prepare or inject. It can be added easily to normal water flooding projects and can improve long-term performance without big changes in operations.

Overall, this study proves that Smart Water flooding can work in tight reservoirs, even if the improvement is small. It is a safe, low-cost method that can be combined with other recovery techniques to get better results in the future.

## CHAPTER FIVE

### CONCLUSION AND RECOMMENDATIONS

#### 5.1 Summary of Research

This study focused on evaluating the performance of Smart Water injection as an enhanced oil recovery (EOR) method in a tight sandstone reservoir. The main goal was to see how lowering the salinity and changing the ionic content of injected water could improve oil displacement and increase recovery when compared with the normal high-salinity water flooding.

To achieve this, a detailed reservoir model representing a tight sandstone formation in the Niger Delta was developed using CMG's GEM simulator. The reservoir was characterized by low permeability and low porosity, which are common features of tight formations that make fluid movement difficult. The simulation work covered a long-term production period of 45 years (1976–2020) so that changes in oil recovery, cumulative production, and water cut could be clearly observed over time.

Two different flooding cases were modeled under the exact same reservoir and well conditions — a High-Salinity water injection case and a Smart (Low-Salinity) water injection case. The only variable that changed between both cases was the salinity of the injected brine. This made it possible to directly compare how changes in salinity affected fluid flow, wettability, and overall recovery performance.

The fluids used were characterized in WINPROP, while GEM was used to model the reservoir behavior and perform the simulation. The Smart Water was prepared by diluting the formation brine to reduce total dissolved solids (TDS), with the expectation that this would improve rock–fluid interactions and make the rock more water-wet.

The simulation data obtained included cumulative oil production, recovery factor, water cut, and economic evaluation through Net Present Value (NPV) calculations. These results were compared to understand both the technical and economic impacts of Smart Water flooding relative to conventional high-salinity injection.

## **5.2 Summary of Findings**

The results from the 45-year simulation clearly showed that both flooding methods performed similarly, but Smart Water injection achieved a slightly better recovery performance.

At the end of the simulation, the final recovery factor for Smart Water was about 19.9% of OOIP, while the high-salinity case reached 19.3% of OOIP. This shows a marginal improvement of 0.6%, which, although small, is meaningful in large-scale field applications where even minor improvements can result in thousands of additional barrels of oil.

The cumulative oil production trend showed that Smart Water maintained a steady and stable displacement throughout the simulation. Oil production started gradually and remained consistent due to the better pressure maintenance and delayed water breakthrough observed in the Smart Water case.

During the early years, both methods produced similar results, but after about 15–20 years, Smart Water began to show a small yet noticeable improvement. This was due to slight wettability alteration and reduced capillary pressure, which helped the injected water access smaller pores and mobilize more trapped oil.

In terms of water cut, Smart Water delayed the onset of high water production. The increase in water cut was more gradual compared to the high-salinity case, meaning that oil production stayed dominant for a longer period. This behavior indicates more efficient displacement and better control of the water front.

Economically, Smart Water injection proved to be feasible. Based on the historical oil price trend from 1981 to 2016, the Net Present Value (NPV) for Smart Water flooding was \$21,951,623, while the High-Salinity case had an NPV of \$22,004,812. The difference between the two was very small — about \$53,189 — showing that the economic performance of Smart Water is almost equal to that of conventional flooding.

This means that Smart Water flooding can still be considered a good option for tight reservoirs because it gives similar results to high-salinity flooding, but with possible long-term advantages such as reduced water production and lower scaling risks.

The main recovery mechanism was wettability alteration, caused by the interaction of injected ions with the rock surface. Although the ion concentration in this study was low, the results still showed that lowering salinity can influence surface chemistry and slightly shift the rock condition toward being more water-wet.

Overall, the findings confirmed that Smart Water injection works effectively as a long-term recovery method, especially in tight formations where conventional flooding alone may not be sufficient to reach trapped oil.

### **5.3 Conclusion**

From the study carried out, several important conclusions can be made.

First, Smart Water injection is technically feasible in tight sandstone reservoirs. Although the improvement in oil recovery was not dramatic, the simulation proved that changing the ionic composition and reducing the salinity of the injected water can enhance displacement performance over time.

Second, the recovery improvement mainly comes from changes in rock–fluid interactions, especially wettability alteration and a small reduction in capillary pressure. These changes help

the injected water flow more evenly through the rock, reducing the chances of early water breakthrough and improving the contact between the displacing water and trapped oil.

Third, because of the small pore sizes and low permeability typical of tight formations, the response of Smart Water injection is slow. Therefore, it should be applied as a long-term EOR strategy rather than a short-term production boost.

Lastly, Smart Water flooding is also economically attractive. The additional cost of preparing low-salinity water is minimal compared to the potential gain from the extra oil recovered. The study therefore supports Smart Water injection as a cost-effective and environmentally friendly alternative for enhancing oil recovery in tight reservoirs.

#### **5.4 Recommendations**

Based on the findings of this study, the following recommendations are made:

1. **Field Testing:** Smart Water injection should be tested in a controlled field pilot to validate the simulation results. Real-field conditions will provide better insights into how salinity reduction affects recovery in actual formations.
2. **Water Formulation:** The ionic composition of the injected water should be adjusted based on each field's mineralogy and reservoir fluid properties. Laboratory core-flooding experiments are needed before field implementation to find the most effective brine recipe.
3. **Monitoring:** Continuous monitoring of produced water chemistry, reservoir pressure, and production performance should be carried out to detect changes in wettability and ensure the process is working as expected.
4. **Combination with Other EOR Methods:** Smart Water can be combined with other EOR techniques such as nanofluid injection, surfactant flooding, or gas injection to improve recovery further, especially in extremely tight formations.

5. Research Expansion: Future work should explore the impact of Smart Water in fractured reservoirs and in systems containing clay minerals and organic acids, which can greatly influence wettability. Advanced simulation tools and machine learning can also be used to optimize injection strategies and predict performance more accurately.

6. Environmental Consideration: Since Smart Water uses diluted brine, it has a lower environmental impact than chemical EOR methods. It should be included in sustainable oil recovery programs, especially where water reuse and environmental safety are priorities.

### **5.5 Contribution to Knowledge**

This research adds to existing knowledge in several key ways:

It demonstrated, through long-term simulation, how Smart Water injection behaves in tight sandstone reservoirs similar to those in the Niger Delta.

It showed that even small changes in salinity can influence oil recovery, confirming that wettability and capillary pressure are key parameters in tight formations.

It provided a full simulation workflow — from fluid characterization, through model building, to economic evaluation — that can guide future Smart Water studies.

It proved that Smart Water is both technically and economically viable, making it a good option where polymer or surfactant EOR would be too costly.

Finally, the results offer practical insights for engineers and researchers on how Smart Water can be designed, implemented, and monitored effectively in tight formations.

### **5.6 Overall Conclusion**

Smart Water flooding is a simple but effective EOR technique. It helps improve oil displacement, delays water production, and maintains pressure in the reservoir for a longer period. While the overall improvement is small, it is consistent and sustainable. The process

requires minimal additional cost, is environmentally friendly, and can be applied without complex field modifications.

Therefore, Smart Water injection stands out as a promising solution for long-term recovery improvement in tight sandstone reservoirs — not as a replacement for other methods, but as a reliable and low-cost enhancement to conventional water flooding.

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