

**OPTIMISATION OF INJECTION PARAMETERS FOR ENHANCED  
OIL RECOVERY IN A BLACK OIL RESERVOIR**



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**A PROJECT SUBMITTED TO THE  
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IN PARTIAL FULFILLMENT OF THE REQUIREMENT FOR THE  
AWARD OF BACHELOR OF ENGINEERING (B.ENG) DEGREE IN  
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**DEPARTMENT OF PETROLEUM ENGINEERING  
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## CERTIFICATION

This is to certify that this project was carried out by IRIEKEFE OVIE MARVELLOUS of the Department of Petroleum Engineering with matriculation number ENG2002616 in partial fulfilment of the requirement for the Award of the Degree, Bachelor of Engineering (B.ENG).

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## **DEDICATION**

This project is dedicated to GOD Almighty, whose grace and guidance made it possible to successfully complete this study. It is also dedicated to my loving mother DORIS BIAKORO, whose endless support and prayers have been a constant source of strength, and to my fiancée HELEN CHIDINMA UWAEGBULEM whose understanding, encouragement, and unwavering belief in me have inspired me to keep pushing forward. Truly, even the greatest goals can be achieved when taken one step at a time.

## **ACKNOWLEDGEMENT**

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Finally, I will forever be grateful to UNIVERSITY OF BENIN for the opportunity and exposure privilege given to me during my industrial training process.

## ABSTRACT

This study investigates how optimising injection parameters can improve oil recovery performance in black oil reservoirs using enhanced oil recovery (EOR) techniques. Using CMG's IMEX and STARS simulators, this research examined the influence of injection rate and pressure variations on reservoir recovery efficiency. Three EOR techniques were examined: waterflooding, polymer flooding, and steam injection. Multiple simulation scenarios were conducted on a three-dimensional reservoir model to determine the optimal parameter combinations for maximising oil production. Analysis revealed that injection rate and pressure significantly influenced overall recovery efficiency. While waterflooding outperformed primary depletion methods, polymer flooding yielded the best results in terms of recovery factor and total oil produced, primarily by enhancing sweep efficiency and minimising water production. Steam injection improved recovery by reducing oil viscosity via heat transfer, though it ranked second to polymer flooding under the modeled conditions. Based on the simulation results, polymer flooding emerged as the most effective method for the studied reservoir conditions, indicating strong applicability for Niger Delta black oil reservoirs.

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# CHAPTER 1

## INTRODUCTION

### 1.1 Background of Study

For decades, crude oil has powered our world's economy. Despite the growing push towards renewable energy sources such as solar, wind, and hydroelectric power, oil remains the backbone of global transportation, industrial operations, and power generation in most countries. This reality explains why maximising oil extraction from existing reservoirs has become increasingly critical for the petroleum industry. The challenge is significant: natural reservoir processes alone can only recover a fraction of the oil trapped underground.

Initially, when a reservoir is discovered, engineers rely on its natural energy to bring oil to the surface, a process known as primary recovery. This natural energy might come from dissolved gas expanding within the oil, pressure from a gas cap above the reservoir, or water pushing in from surrounding aquifers. Unfortunately, these natural forces are surprisingly inefficient, typically recovering only 5% to 20% of the oil originally present in the reservoir.

Once this natural drive weakens, production drops sharply, leaving most of the oil stranded underground. To address this, engineers turn to secondary recovery techniques, most commonly waterflooding. By injecting water through strategically placed wells, they can push additional oil towards production wells, boosting recovery to roughly 30–40% of the original oil in place (OOIP). This represents a substantial improvement, yet it still means that more than half of the reservoir's oil remains unrecovered.

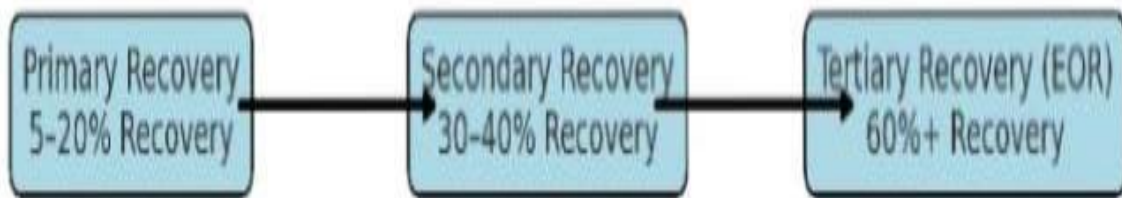
The need to extract this remaining oil led to the development of Enhanced Oil Recovery (EOR) methods, also known as tertiary recovery. Unlike conventional approaches, EOR techniques

actively alter the physical and chemical properties of either the reservoir fluids or the rock itself to mobilise trapped oil. When properly applied, these methods can push total recovery beyond 60% of the original oil in place (U.S. Department of Energy, [2025](#)). The three main categories of EOR are:

**Gas injection** – it involves pumping gases such as carbon dioxide, nitrogen, or natural gas into the reservoir to increase pressure or mix with the oil to improve its flow characteristics.

**Thermal recovery** - it uses heat typically in the form of steam to reduce oil viscosity and make it flow more easily towards production wells.

**Chemical flooding** - employs specialised chemicals like surfactants, polymers, or alkaline solutions to reduce the forces that trap oil in tiny pore spaces and improve how effectively the injected fluids sweep through the reservoir.



*Figure 1-1: Stages of Oil Recovery.*

Black oil reservoirs represent some of the most common reservoir types encountered in the petroleum industry and have been extensively studied in Nigeria's Niger Delta region. These reservoirs contain medium to moderately viscous crude oil that responds predictably to changes in pressure and temperature, characteristics that make them suitable candidates for various EOR techniques including waterflooding, polymer flooding, and steam injection. However, simply choosing an EOR method isn't enough; the effectiveness of these techniques hinges critically on

how the injection process is executed.

Selecting the right injection parameters represents one of the biggest challenges in EOR design. Recovery outcomes can vary dramatically based on injection rate, pressure, fluid composition, temperature (particularly for steam), and timing. Setting the injection rate too low leads to weak oil displacement and disappointing recovery (Sidiq et al., 2019). On the other hand, injecting too aggressively causes the injected fluid to break through prematurely at production wells, a costly mistake that wastes resources and undermines the entire recovery effort. Similarly, injection pressure must be carefully controlled to avoid exceeding the reservoir's fracture pressure, which could permanently damage the formation. For steam injection, temperature control is equally critical because heating the oil reduces its viscosity significantly and improves flow. These considerations highlight why injection parameters must be properly optimised to achieve the best possible results.

Testing different injection strategies directly in the field would be prohibitively expensive and risky. Such an approach demands drilling multiple wells, injecting massive volumes of fluids, and monitoring performance over many years, all whilst gambling with millions of dollars. A single miscalculation can lead to enormous financial losses and permanently damage the reservoir's productive capacity. This is why petroleum engineers rely on reservoir simulation as a safer, more cost-effective way to test various scenarios virtually before committing resources in the field.

Reservoir simulation uses sophisticated computer models to replicate reservoir behaviour under various operating conditions. These models allow engineers to forecast oil recovery rates, track pressure changes over time, and visualise how injected fluids will migrate through the reservoir. The ability to rapidly test multiple strategies virtually translates into significant cost savings and

risk reduction.

For this study, I used Computer Modelling Group (CMG) software, one of the industry's leading reservoir simulation platforms. CMG's powerful modelling capabilities made it possible to build a detailed representation of a black oil reservoir and systematically evaluate different EOR strategies under varying injection conditions. The software enabled me to analyse critical performance indicators such as water cut, pressure distribution, cumulative oil production, and recovery factor across multiple scenarios. By running sensitivity analyses, varying one parameter at a time to observe its impact, I could determine the optimal combination of injection settings. For example, I could compare whether lower injection rates produce more stable long-term recovery or if higher rates yield better overall results. I could also evaluate whether gas injection outperforms steam injection under specific reservoir conditions. This systematic approach formed the foundation of my optimisation study.

## **1.2 Statement of Problem**

Despite decades of oil production in Nigeria, particularly in the Niger Delta region, a troubling reality persists, most of our black oil reservoirs still contain vast amounts of crude oil that remains trapped underground. Even after primary recovery methods have been exhausted, and in many cases after secondary recovery techniques have been applied, the majority of the original oil remains locked in the reservoir rock.

This problem is especially acute in the Niger Delta, where black oil reservoirs dominate. These reservoirs typically contain medium to heavy crude oils that are significantly more difficult to mobilise and produce compared to lighter oils. The physical properties of these oils; particularly their higher viscosity, make them resistant to conventional extraction methods.

Although secondary and tertiary recovery techniques such as waterflooding, polymer flooding, and steam injection have been deployed in various Nigerian oil fields, their success has been inconsistent and often disappointing. In many cases, these expensive EOR projects have failed to deliver the expected improvements in oil recovery, leaving operators frustrated and questioning whether the investment was worthwhile.

The root cause of these disappointing results often lies not in the choice of EOR method itself, but rather in how these methods are implemented. Specifically, the injection parameters; injection rate, injection pressure, timing of injection, and in the case of steam injection, the temperature and steam quality, are frequently not properly optimized for the specific reservoir conditions.

This study proposes a three-step approach:

**Reservoir and Fluid Characterisation** – understanding the black oil reservoir properties, fluid behaviour, and production history in order to build a representative simulation model.

**Simulation of Different Injection Scenarios** – using CMG to test water flooding, polymer flooding, and steam injection under varying conditions (injection rate, pressure, timing, steam quality/temperature, etc.).

**Optimisation and Evaluation** – analysing the simulation results to identify the best set of injection parameters that give the highest recovery efficiency with minimal losses.

By combining these methods, this study seeks to develop a practical framework for improving oil recovery in Nigerian black oil reservoirs. The integration of reservoir characterisation, simulation of different injection techniques, and optimisation of key parameters is expected to provide insights that are both technically reliable and applicable in real field operations. In doing

so, the study not only demonstrates the potential of CMG as a tool for reservoir management but also contributes to addressing one of the major challenges in Nigeria's petroleum industry maximising recovery from ageing and complex reservoirs.

### **1.3 Aim and Objectives**

Throughout this investigation, my primary focus will be on completing the following objectives:

1. To understand how EOR methods such as polymer flooding, water flooding, and steam injection work in black oil reservoirs.
2. To develop a black oil reservoir model using CMG and test different injection settings (rate, pressure, and fluid type).
3. To determine which injection setup gives the best oil recovery and suggest how it can help improve EOR planning.
4. To evaluate the effect of injection timing and sequence on recovery efficiency in black oil reservoirs.
5. To optimise the injection parameters and identify the most cost-effective strategy for improved oil recovery.
6. To provide recommendations that can support field engineers and decision-makers in planning EOR projects in Nigeria.

### **1.4 Significance of Study**

Low crude oil recovery from black oil reservoirs is one of the main issues facing Nigeria's petroleum industry, which makes this study significant. Because primary and secondary recovery

methods are not enough to bring out large volume of crude oil from the reservoir, a significant amount of oil remains trapped underground despite decades of oil production. This study aims to demonstrate how recovery can be enhanced with the proper injection parameters by concentrating on enhanced oil recovery (EOR) techniques like steam injection, polymer flooding, and water flooding.

Another key significance is that the study uses CMG simulation software, which provides a safe, cost-effective, and flexible way of testing different reservoir scenarios without the risks and expenses of field trials. This makes it possible to identify the best injection strategy before it is applied in real operations. The results of this study can therefore provide guidance for engineers and decision-makers on how to design and manage EOR projects more efficiently.

This study is also significant from an economic and social standpoint in Nigeria. The government will make more money, existing fields will last longer, and the nation's energy security will improve with increased oil recovery. Enhancing recovery efficiency also lessens the need to drill needless new wells, which can have a positive environmental impact.

Finally, this study contributes to my knowledge by showing how simulation tools can be applied in reservoir engineering to solve practical field problems. For me as a student, it also helps me gain hands-on experience with modern petroleum engineering software, which is a valuable skill for my future career.

## **1.5 Scope of Study**

This thesis uses CMG simulations to analyse and optimise enhanced oil recovery (EOR) methods in black oil reservoirs. The study is centred on testing and adjusting injection parameters to determine how they affect overall oil recovery. The focus is on:

Evaluating water flooding, polymer flooding, and steam injection in a representative black oil reservoir.

Examining the impact of injection parameters such as rate, pressure, timing, and steam quality/temperature on recovery efficiency.

Demonstrating how CMG simulation results can guide decision-making for better EOR planning and implementation in Nigerian reservoirs.

## **1.6 Limitations**

Several limitations may arise during this research, potentially attributable to:

Accuracy limitations of reservoir models due to assumptions and data uncertainties used in simulation.

Real-world implementation complexities which extend beyond the controlled conditions of simulation parameters.

Economic considerations, since cost analyses are based on estimations and may not fully capture field-specific variations.

Insufficient computational power or simulation resources, which may restrict the size or complexity of models that can be run.

## CHAPTER 2

### LITERATURE REVIEW

#### 2.1 Introductions

The petroleum industry has developed increasingly sophisticated methods for extracting oil from underground reservoirs over the past century. These methods are conventionally grouped into three progressive stages: primary, secondary, and tertiary (or enhanced) recovery. Each stage represents a step up in technological complexity and intervention level, applied as the easier, cheaper methods become exhausted.

During primary production, operators rely entirely on natural reservoir energy to drive oil towards producing wells. This natural energy might come from several sources: gas dissolved in the oil that expands as pressure drops, a gas cap sitting above the oil zone that pushes downward, an active aquifer beneath the reservoir that pushes upward, or simply gravity pulling oil downward into lower wells. Whilst these natural mechanisms require minimal infrastructure investment, they're remarkably inefficient, typically recovering only 5% to 20% of the oil originally in place (OOIP) before reservoir pressure drops too low to sustain economic production (Ahmed, 2019).

Once primary depletion reaches its limit, operators must decide whether to abandon the field or invest in secondary recovery techniques. Waterflooding has emerged as the dominant secondary recovery method globally because of its relative simplicity and proven effectiveness. By injecting water through dedicated injection wells, engineers can maintain reservoir pressure whilst physically displacing oil towards production wells. This approach typically adds another 15% to 25% to the recovery factor beyond what primary production achieved (Lake et al., 2014).

However, even this improvement leaves a frustrating reality, after both primary and secondary recovery have been exhausted, roughly half to two-thirds of the original oil remains trapped in the reservoir.

This is where enhanced oil recovery (EOR) enters the picture. EOR methods, sometimes called tertiary recovery, though they can be applied earlier: employ more sophisticated interventions to mobilise oil that conventional techniques cannot reach. Rather than simply maintaining pressure or pushing oil mechanically, EOR alters the fundamental physics and chemistry of the reservoir system. Depending on the specific technique and reservoir characteristics, EOR can potentially recover an additional 5% to 20% of the original oil in place (OOIP), though results vary widely (Green & Willhite, 2018).

Understanding how these recovery methods work, their limitations, and how to optimise them is crucial for my research. Black oil reservoirs; the focus of this study, are particularly amenable to certain EOR techniques, but only if the injection parameters are properly designed. The literature reviewed in this chapter provides the theoretical foundation for understanding why injection rate, pressure, timing, and fluid properties matter so much for EOR success.

Modern reservoir simulation has become indispensable for EOR planning because it allows engineers to test different strategies virtually before committing to expensive field implementation. The Computer Modelling Group (CMG) software suite, which I used for this research, represents decades of accumulated knowledge about how to mathematically represent reservoir behaviour. Understanding what CMG can and cannot model, and how to properly set up simulations, requires familiarity with both the underlying physics and the specific software capabilities.

## 2.2 Oil Recovery Techniques

The evolution of oil recovery methods reflects the industry's ongoing struggle to extract an increasingly stubborn resource. As each generation of technology reaches its practical limits, engineers have developed more aggressive interventions to access what remains. The classification into primary, secondary, and tertiary stages reflects not just a chronological progression but fundamentally different philosophies about how to mobilise oil: relying on nature, assisting nature, or overriding nature entirely (Ahmed, 2010).

### 2.2.1 Primary Recovery

Primary recovery represents the initial, least intrusive phase of hydrocarbon extraction. During this stage, production wells simply tap into the reservoir's existing energy, allowing natural forces to drive oil to the surface without external assistance. Several distinct physical mechanisms can provide this natural drive energy, such as;

**Solution gas drive** – in solution gas drive reservoirs, gas dissolved within the oil under high pressure acts as the energy source. As production lowers reservoir pressure, this dissolved gas comes out of solution and expands, providing the force needed to push oil towards the wellbore.

**Water drive** - this occurs when an active aquifer surrounds or underlies the oil accumulation; as reservoir pressure drops, water from this aquifer expands into the oil zone, displacing oil upward and towards producing wells.

**Gas cap drive** – this relies on a zone of free gas sitting above the oil; as oil is produced and pressure declines, this gas cap expands downward, pushing oil ahead of it.

**Gravity drainage** – this is the simplest mechanism, occurs in steeply dipping reservoirs where oil literally flows downhill towards structurally lower wells.

In the early days of a field's life, these natural mechanisms often produce oil vigorously without pumping equipment. However, this initial enthusiasm is deceptive (Ahmed, 2019).

As pressure inevitably declines, flow rates drop, and artificial lift equipment—electric submersible pumps, rod pumps, or gas lift systems—must be installed to continue production. Even with artificial lift, primary recovery typically exhausts itself after recovering only 5% to 20% of the original oil in place (Lake et al., 2014).

Although the recovery factor is small, primary recovery is significant because it provides valuable information about reservoir behaviour and serves as the basis for designing secondary and tertiary recovery operations (Green & Willhite, 2018).

### 2.2.2 Secondary Recovery

Secondary recovery is applied once the natural energy (primary recovery) of the reservoir becomes insufficient to sustain oil production at economic rates. The main aim of the secondary recovery is;

- **Pressure maintenance:** By preserving reservoir pressure, secondary recovery methods like gas injection and water-flooding allow oil to continue flowing into the wells.
- **Improving sweep efficiency:** By displacing oil more effectively towards production wells by injecting fluids (water or gas).

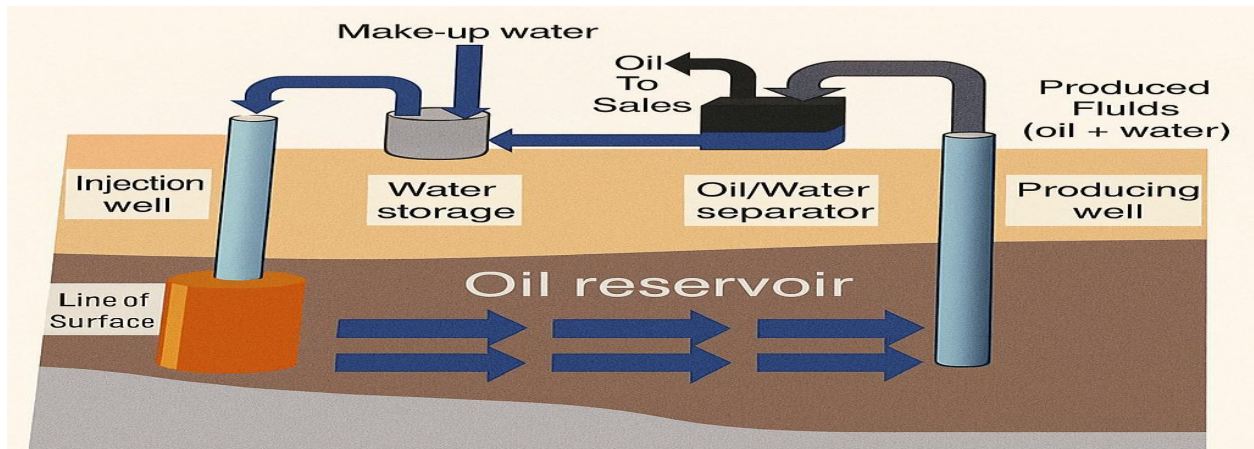
According to the miscibility of the injected fluid with the reservoir oil, secondary recovery can generally be divided into:

- Immiscible waterflooding.
- Immiscible gas (e.g., nitrogen, flue gas, natural gas at non-miscible conditions).

Secondary recovery methods, such as water flooding and gas injection, typically contribute an additional recovery of about 15–25% of the stock tank oil initially in place (STOIP), over what is achieved during primary recovery (Ahmed, 2019).

### 2.2.2.a Waterflooding

The most popular secondary recovery technique is water flooding, which is employed to keep reservoir pressure stable and move more oil when natural energy starts to wane. It entails forcing oil towards producing wells by injecting water through particular wells. Water flooding is easy, economical, and can boost recovery by roughly 15–25% of the original oil in place, despite potential problems like early water breakthrough and bypassed oil in heterogeneous reservoirs



(Ahmed, 2019).

*Figure 2-1: Illustration of water injection.*

### 2.2.3 Tertiary Recovery (Enhanced Oil Recovery, EOR)

After conventional primary and secondary methods have extracted all they economically can, the reservoir still contains a frustrating amount of oil—often 50% to 70% of what

was originally in place (OOIP). This remaining oil isn't inaccessible because of insufficient technology or effort. Rather, fundamental physical and chemical forces trap it in ways that conventional recovery methods cannot overcome.

Capillary forces hold oil in tiny pore throats where surface tension exceeds the displacing force of injected water. Unfavourable viscosity ratios allow water to bypass oil-saturated zones, flowing preferentially through easier paths. Heterogeneous rock properties create bypassed zones that waterfloods never sweep effectively. In heavy oil reservoirs, the oil itself may be too viscous to flow under reservoir conditions, remaining stubbornly immobile despite adequate pressure (Green & Willhite, 2018).

Enhanced Oil Recovery (EOR) techniques attack these problems directly by altering the fundamental physics and chemistry of the reservoir system. Rather than simply applying more pressure or injecting more water, EOR methods change how oil, water, rock, and gas interact at the pore scale. This might involve heating the reservoir to reduce oil viscosity, injecting chemicals to reduce interfacial tension, or introducing gases that become miscible with the oil.

The three major categories of EOR reflect different approaches to modifying reservoir behaviour:

**1. Thermal recovery** – this address viscosity-dominated problems by heating the reservoir. Steam injection, in-situ combustion, and hot water flooding all work by raising temperature, which dramatically reduces oil viscosity and allows it to flow more easily. This approach proves most effective in heavy oil reservoirs where room-temperature viscosity is the primary barrier to production.

**2. Chemical EOR** - modifies the interface between oil and water or alters fluid mobility

ratios. Polymer flooding increases the viscosity of injected water, creating a more favourable mobility ratio and improving sweep efficiency. Surfactant flooding reduces interfacial tension between oil and water, allowing oil to be mobilised from small pores where capillary forces would otherwise trap it. Alkaline flooding generates surfactants in situ by reacting with acidic components in the crude oil (Lake et al., 2014).

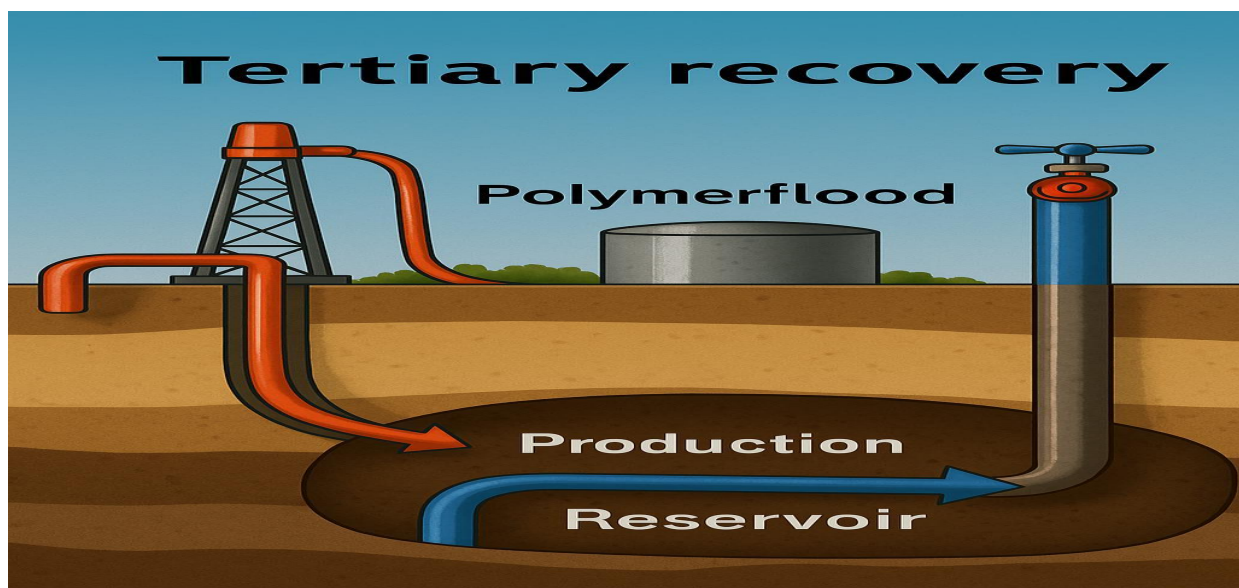
**3. Gas injection** - this uses injected gases, most commonly carbon dioxide, nitrogen, or hydrocarbon gases, to displace oil. At sufficiently high pressure, some gases become miscible with reservoir oil, eliminating interfacial tension entirely and providing extremely efficient displacement. Immiscible gas injection, whilst less efficient, can still improve recovery by maintaining pressure and providing gas drive energy.

The potential of EOR is considerable. Under favourable conditions, EOR can recover an additional 10% to 20% of the original oil in place (OOIP), or even more in some cases.

However, this potential comes at a cost. EOR projects require substantial capital investment in injection facilities, monitoring equipment, and often specialised chemicals or gases. Operating costs can be high, particularly for thermal methods that consume large amounts of energy. Success is far from guaranteed; many EOR projects have failed to meet expectations because of inadequate reservoir characterisation, poor project design, or unfavourable economics.

### 2.2.3.a Polymer Flooding

Polymer flooding represents one of the most commercially successful EOR methods, with hundreds of field applications worldwide demonstrating its effectiveness in improving oil recovery beyond conventional waterflooding. To increase the viscosity of the injected fluid and mobility ratio between displacing and displaced phases, in this method water was mixed with polymers before being injected. The method enhances sweep efficiency of the reservoir and reduces water fingering. As it reduces the movement of injected water through the reservoir and, in so doing, increases both areal and vertical sweep, polymer flood (and its implicit conformance solution), when properly engineered contributes to a more even displacement of oil toward producing wells. As conventional waterflooding is becoming increasingly less effective, this technique is applicable mainly in tertiary recovery. From this point of view polymer flooding, also can be considered as an augmented secondary recovery to delay water breakthrough and improve overall oil recovery. Overall, polymer flooding assists in recovering significant amounts of residual oil that would otherwise remain unrecovered after primary and secondary production



stages.

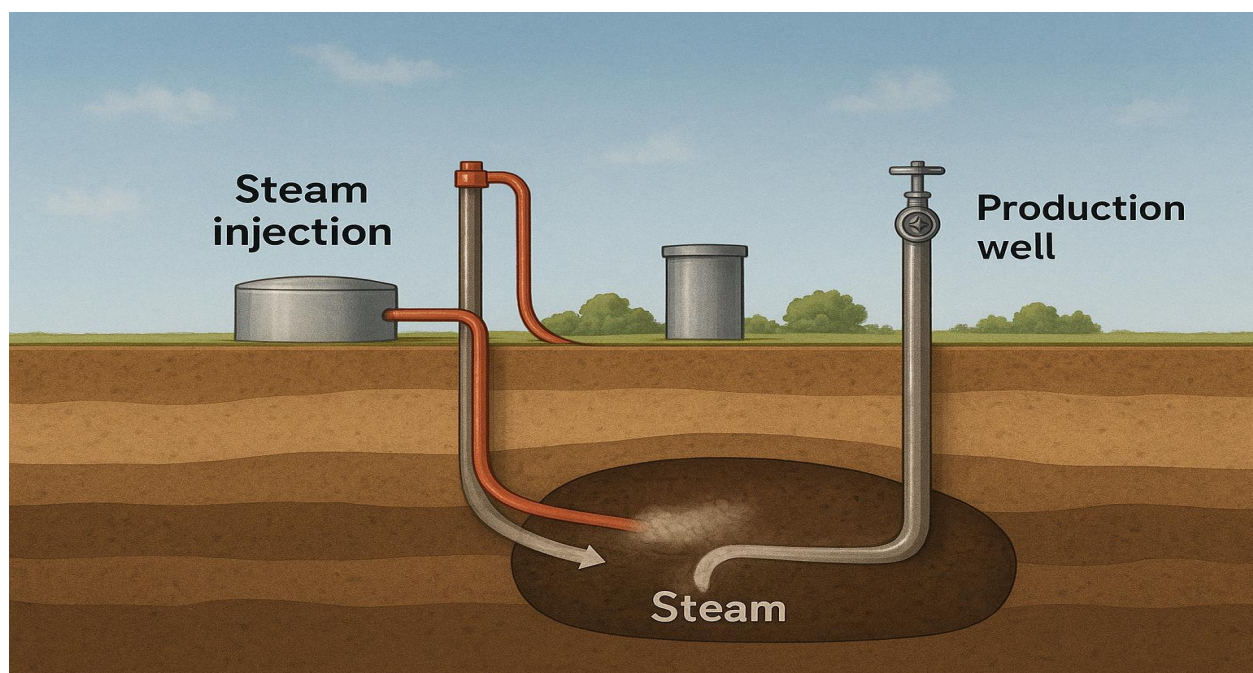
*Figure 2-2: Polymer Flooding Mechanism.*

### 2.2.3.b Steam Injection (Thermal EOR)

Steam injection is a form of thermal enhanced oil recovery employed on difficult to extract heavy oil reservoirs. This method utilizes an injection well to put in steam at high pressure. The steam increases both the temperature and pressure in the reservoir area. Alleviating the pressure along with the temperature allows the heavy oil to flow more easily. Moreover, the steam pressure keeps the oil moving toward the production well. There are various methods of steam application including;

- **Cyclic steam stimulation** where steam is injected, the well is closed to soak, and production is resumed.
- **Steam flooding** which is continuous steam injection.

This method has proven steam flooding has had a substantial impact on improving oil recovery



in shallow, viscous oil reservoirs.

*Figure 2-3: Steam Injection Mechanism.*

### **2.3 Reservoir Simulation in EOR**

In EOR projects, reservoir simulations are often carried out using specialized applications such as CMG, which is known throughout in academia and industry. CMG has;

- **IMEX:** for black oil models; best for waterflooding, pressure maintenance, and simple gas injection cases.
- **STARS:** for thermal simulations such as steam flooding or in-situ combustion; used for thermal EOR (steam, combustion, chemical flooding).
- **GEM:** for compositional and miscible gas injection studies which are all tailored for EOR processes; used when fluid composition and miscibility matter (e.g. CO<sub>2</sub> flooding).

Engineers are able to validate different EOR strategies and simulations by creating detailed

Reservoir models and inputting rock and fluid properties alongside running different rock and fluid predictive scenarios.

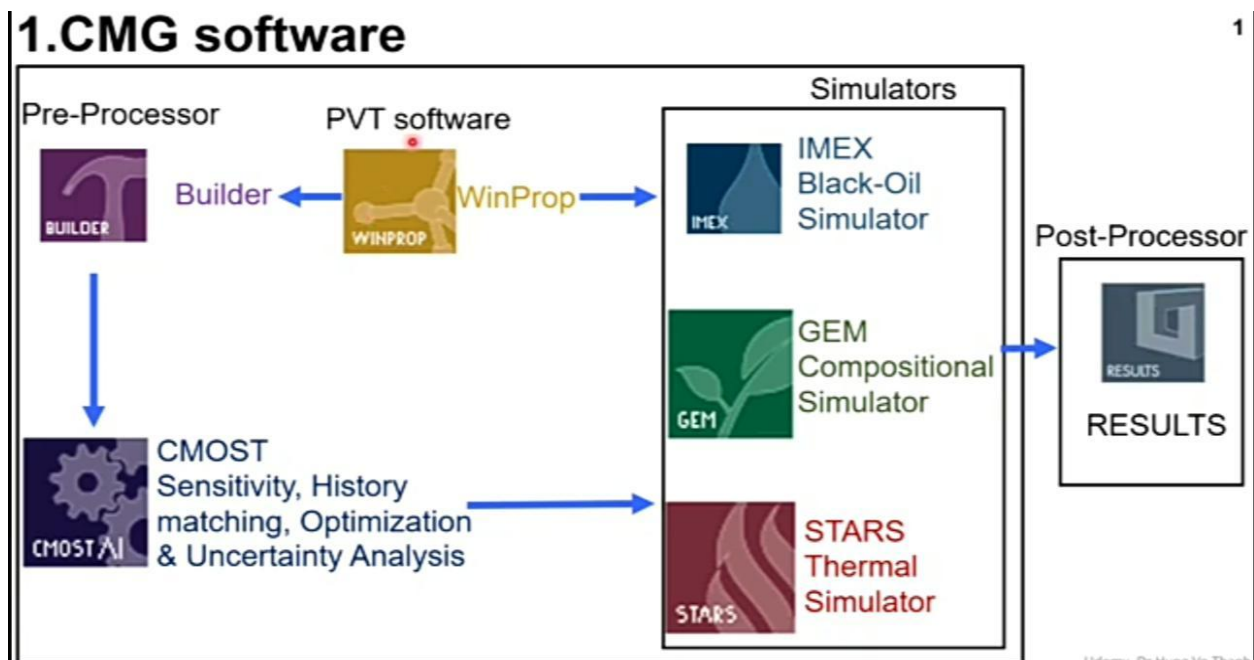
Reservoir performance prediction and field development require reservoir simulation. It helps in forecasting production and recovery with different reservoir engineering techniques and evaluating uncertainties associated with reservoir behaviour. Simulation helps to optimise in well locations, injections, and production rates with less risk and cost. Through considerable economic insight blended with technical accuracy, simulation improves informed decisions on recovery optimisation.

The challenges are that we need exact computing, we need model assumptions to work out accurately, and the data input needs to be perfect. Reliable predictions are therefore directly proportional to calibrations and history matching. Reservoir description and fluid behavior are sensitive to accurate input and, if not correctly known, may result in unreliable predictions.

## 2.4 Modelling Workflow

In CMG's software, the reservoir simulation process is quite standard, followed by the importation of production data, petrophysical data and geological data into the computer. After that comes grid construction where the reservoir is broken up into many discrete blocks with CMG's Builder. Next, comes Model Initialisation process where initially measures such as pressure, saturation conditions, and fluid properties are specified.

After calibrating this model through history match, the parameters are altered over time so as to simulate real production data accurately. Next, the model is put to work to predict and check different recovery scenarios, such as steam injections, polymer flooding, water floods. Finally, by using the CMOST optimization toolkit of CMG, both the most intelligent operation methods



and recovery efficiency can be found.

*Figure 2-4: CMG modelling workflow.*

## **2.5 Introduction to CMG Software**

Computer Modelling Group (CMG) is one of the most widely used reservoir simulation software, Computer Modelling Group (CMG) is widely used in oil and gas industry and research. It aims to enlighten engineers on the influence of different methods on reservoir performance by representing complex recovery mechanisms. Unlike conventional simulators, CMG is primarily developed for Enhanced Oil Recovery (EOR) simulation, so that one can use it for processes like steam injection, polymer flooding and waterflooding.

The primary advantages of CMG are Its flexibility and capability in simulation of multiphase and multi-component systems under different operating conditions. Thanks to a mix of advanced numerical methods and simple-to-use user interfaces, engineers can build, develop and analyse models fast. Its combination with optimisation tools helps in simulating the scenarios leading to reduced uncertainties and in identifying new and best tactics to optimise the oil recovery.

CMG is particularly relevant in regard to this research project as it has the tools necessary to evaluate and optimise polymer flooding, steam injection and waterflood recovery in black oil reservoirs. So, it is easy to predict recovery performance, compare different types of EOR and suggest some attempts to get better field development results by CMG.

## **2.6 Overview of CMG Simulators**

CMG is composed of several types of simulation modules, each aimed at modeling a particular recovery process. These simulators can work in isolation and may be combined depending on the desired study complexity. There are some, that are interesting, for this project, such as;

**IMEX** – This is the black oil simulator used primarily for traditional problems like waterflooding and primary depletion. It is more numerical efficient and suitable for the large field models with simple fluid systems.

**STARS** – This simulator is predominantly used for thermal recovery processes such as steam flooding, cyclic steam stimulation (CSS), and Steam-Assisted Gravity Drainage (SAGD). It simulates heat transfer, phase behaviour, chemical reactions, and other thermal effects that occur within the reservoir. In addition to thermal recovery, CMG STARS can also model chemical enhanced oil recovery (EOR) methods such as polymer flooding and alkaline-surfactant-polymer (ASP) processes. This makes it suitable for simulating complex recovery mechanisms where both thermal and chemical effects influence reservoir performance.

**CMOST** -This is the optimisation toolbox that communicates with the other simulators. It is useful for implementation of sensitivity analysis, uncertainty analysis and operating strategy optimization.

*Table 2-1: Overview of CMG simulators and their applications.*

<b>SIMULATOR</b>	<b>MAIN APPLICATION</b>	<b>RELEVANCE TO PROJECT</b>
<b>IMEX</b>	Black-oil simulation, primary depletion, and waterflooding.	Used to model water injection processes and evaluate recovery efficiency.
<b>STARS</b>	Thermal and chemical recovery processes (steam flooding, cyclic steam stimulation (CSS), SAGD, and polymer flooding).	Used to simulate steam injection for viscosity reduction and polymer flooding for improving mobility control and enhancing oil displacement efficiency.
<b>CMOST</b>	Optimisation toolkit for sensitivity analysis, uncertainty handling, and decision-making.	Supports the project by optimising injection parameters and improving recovery strategies.

## **CHAPTER 3**

### **METHODOLOGY**

#### **3.1 Building the Digital Reservoir: Modelling with CMG**

A digital reservoir model was built with software from the Computer Modelling Group (CMG) to carry out this study. CMG is popular for its advanced simulation models which enable engineers to model different recovery techniques under any number of operational conditions. For this project there were three modules accessed centrally by the CMG Launcher: the Builder, the Results, and the CMOST.

##### **3.1.1 The CMG Technology Launcher**

The Launcher acts as the starting point for building and running simulations. The Builder module was used for creating the reservoir model, while the Results module was applied for visualising production and injection performance. The CMOST module was particularly important as it was used to optimise injection parameters for enhanced recovery. Among the simulator engines, IMEX was suitable for conventional black oil modelling, GEM for compositional studies, and STARS for thermal recovery.

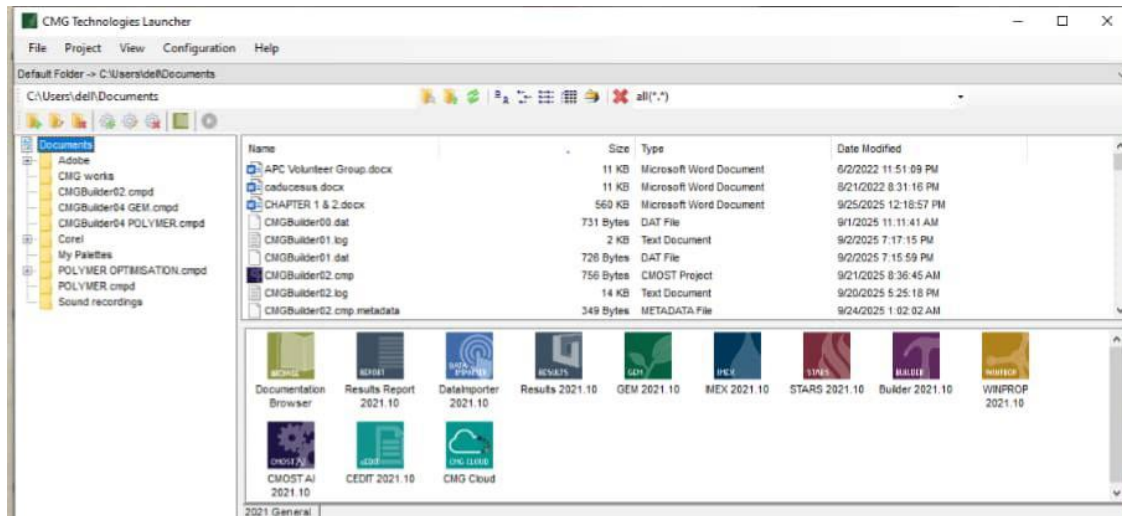


Figure 3-1-: CMG Launcher Interface.

### 3.2 Building the Physical Reservoir Model with CMG Builder

1. Launch the builder.

2. **Selecting simulator type:** Because the reservoir's fluid system is a traditional black oil type, the IMEX black oil simulator was chosen for this project. To indicate the start of the prediction period, field units were employed, a single porosity was selected, and the simulation start date was set for January 1, 2021.

3. **Develop grid discretisation:** A  $25 \times 40 \times 6$  grid was built, with 275 feet of thickness in the i direction and 400 feet in the j direction. The log interpretation and field data were directly used to import the thickness distribution throughout the pay-zone.

4. **Modeling array properties:** The reservoir variability was modeled using array properties. Among these were porosity, permeability ( $k_x$ ,  $k_y$ ,  $k_z$ ), thickness, net-to-gross ratio and grid-top elevations. The data on field reports, core analysis and the well logs.

**5. Build fluid model:** A PVT was used for the reservoir fluids. Liquid salinity, oil API gravity, gas specific gravity, reservoir temperature and bubble point pressure were given. To prepare the model for EOR optimisation, further injection fluid attributes were mapped for steam, gas and

#	Description	Option	Value
1	Reservoir temperature		165 F
2	Generate data upto max. pressure of		5050 psi
3	Bubble point pressure calculation	Value provided	3075 psi
4	Oil density at STC(14.7 psia, 60 F)	Stock tank oil gravity (API)	36
5	Gas density at STC(14.7 psia, 60 F)	Gas gravity (Air=1)	0.7
6	Reference pressure for water properties		2457.348 psi
7	Pressure dependence of water viscosity		0 cp/psi
8	Water salinity (ppm)		12500

water.

*Figure 3-2: Building Black Oil Model using IMEX Simulator.*

**6. Create the relative permeability curves and tables:** Here CMG is used to develop the saturated water and liquid table using the relative permeability data gotten from the field data.

<b>Water-Oil Relative Permeability (SWT)</b>		
<b>Sw</b>	<b>Krw</b>	<b>Krow</b>
0.25	0	0.3
0.283125	0.00117188	0.247192
0.31625	0.0046875	0.200977
0.349375	0.0105469	0.160913
0.3875	0.01875	0.126562
0.415625	0.0292969	0.0974854
0.44875	0.0421875	0.0732422
0.481875	0.0574219	0.0533936
0.515	0.075	0.0375
0.548125	0.0949219	0.0251221
0.58125	0.117188	0.0158203
0.614375	0.141797	0.00915527
0.6475	0.16875	0.0046875
0.680625	0.198047	0.00197754
0.71375	0.229687	0.000585937
0.746875	0.263672	7.32422e-05

**RELATIVE PERMEABILITY TABLES**

Table 3-1: Water-Oil Relative Permeability Table (SWT).

0.78	0.3	0
------	-----	---

<b>Liquid-Gas Relative Permeability (SLT)</b>		
<b>SL</b>	<b>Krg</b>	<b>Krog</b>
0.55	0.3	0
0.573125	0.247192	4.07126e-05
0.59625	0.200977	0.000325701
0.619375	0.160913	0.00109924
0.6425	0.126562	0.00260561
0.665625	0.0974854	0.00508908
0.68875	0.0732422	0.00879392
0.711875	0.0533936	0.0139644
0.735	0.0375	0.0208449
0.758125	0.0251221	0.0296795
0.78125	0.0158203	0.0407126
0.804375	0.00915527	0.0541885
0.8275	0.0046875	0.0703514
0.850625	0.00197754	0.0894456
0.87375	0.000585938	0.111715
0.896875	7.32422e-05	0.137405
0.92	0	0.166759
0.96	0	0.2269

1	0	0.3
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Table 3-2: Liquid-Gas Relative Permeability Table (SLT).

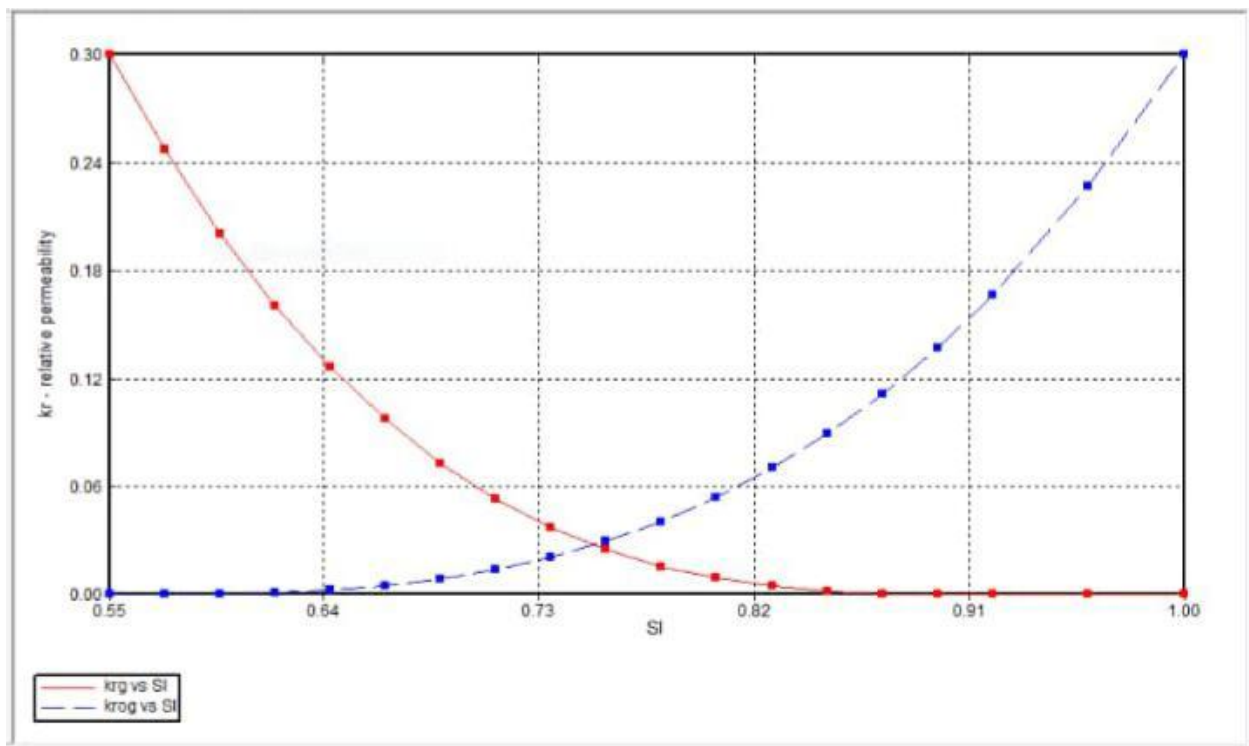
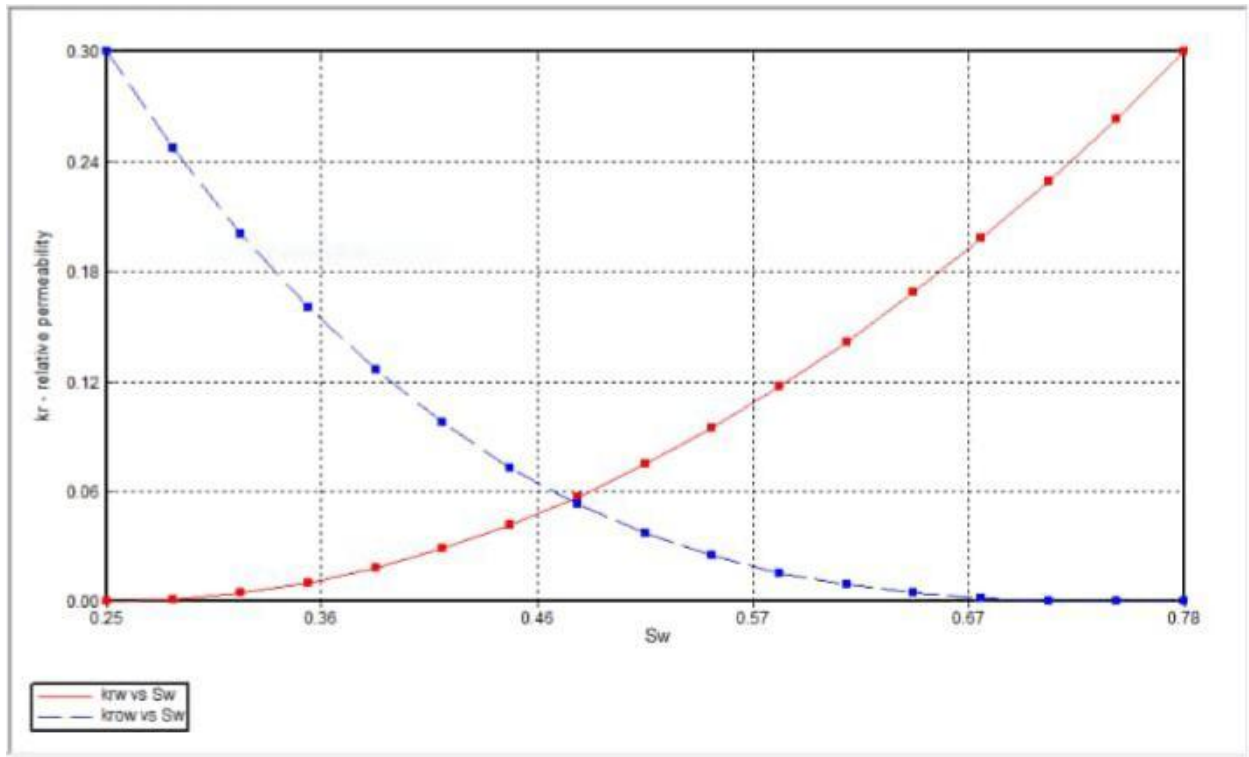


Figure 3-3: Water-Oil Relative Permeability Curve.

Figure 3-4: Liquid-Gas Relative Permeability Curve.

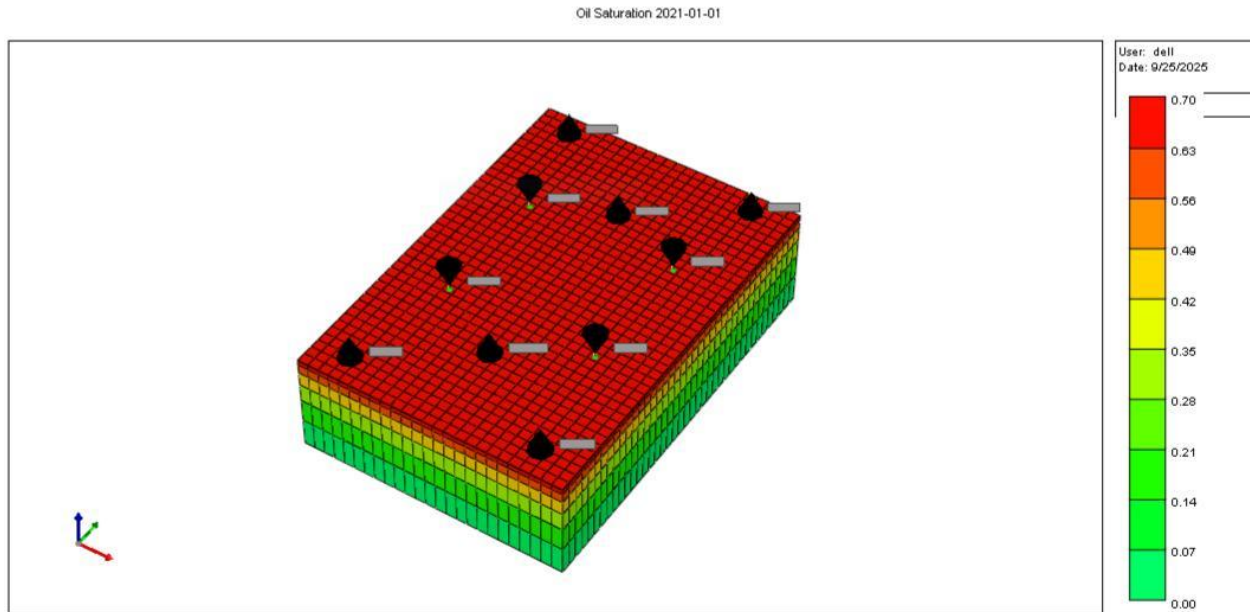
**7. Set the reservoir initial condition:** The reservoir is initialised to depict its state before production commences. Normally, CMG uses the capillary gravity method which is used to calculate the vertical equilibrium, and it is the conventional approach CMG uses to initialise the

reservoir model.

Figure 3-5: Reservoir Initial Conditions.

**.8. Import well trajectory data and perforation data:** 10 wells were created and 8 of them were producers, and two of them were injector wells. The well perforations were set for each wells, and the wells perforated were vertical wells.

**9. Set up well constraints:** The well constraints were used to set up different injection parameters for this project.



**10. Finally the reservoir model was built.**

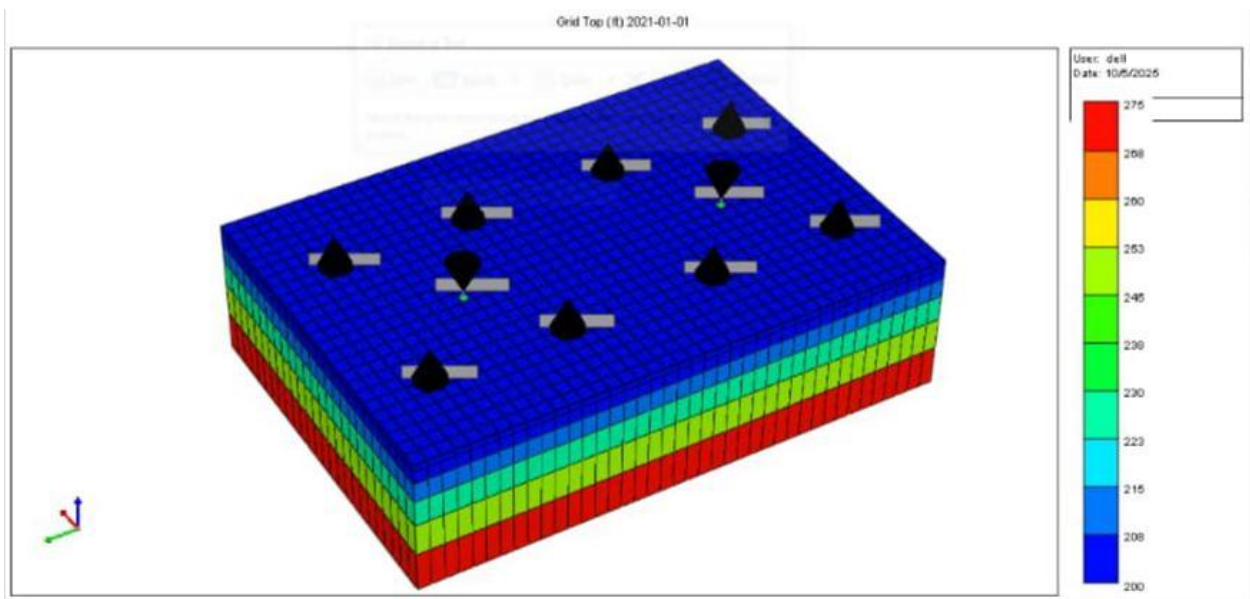


Figure 3-6: The Reservoir Model: Showing Oil Saturation Profile.

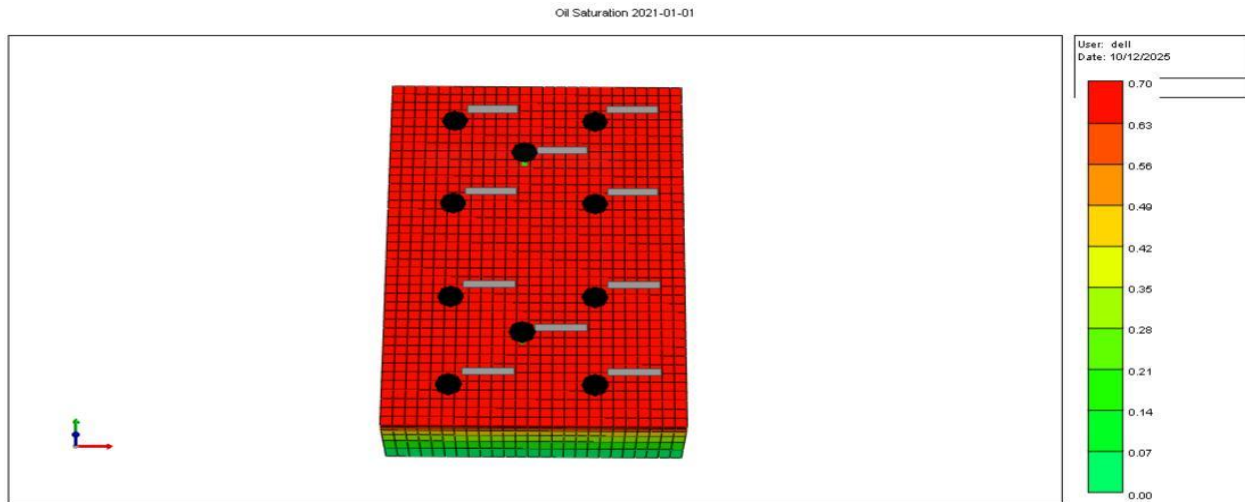
*Figure 3-7: The Reservoir Model: Showing Grid Top Profile.*

### **3.3 Simulation Study Cases**

The (3) different recovery methods were considered using the available wells.

#### **3.3.1 Case 1: Waterflooding**

In this case, the aim is simply to keep reservoir pressure up and improve the areal sweep so we can recover oil that had been bypassed. This waterflood serves as the baseline case for this study, injection rates would be chosen to give pressure support without causing very early water breakthrough. Two (2) injector wells were placed at converging points in the reservoir and the producers were set on the flanks so oil would be pushed steadily towards the production wells, as depicted below:



*Figure 3-8: Visualising Pre-Waterflooding Reservoir Oil Saturation with Injector Wells Placement.*

The waterflooding simulation was carried out to see how injecting water could help maintain reservoir pressure and push more oil towards the production wells. This case served as the base model for the study and was later used to compare the performance of polymer and steam injection.

During the setup in CMG Builder, the following steps were taken;

- Selected suitable points for injection within the reservoir model.
- Inserted two injector wells at the chosen locations.
- Completed the well perforations to connect the injectors with the reservoir layers.
- Defined the well type as **Injector (MOBWEIGHT)**.

- Select well constraints: These are the operating conditions of the well and These will be used for the optimisation of injection parameters for the injector wells.
- Selected **water** as the injection fluid.

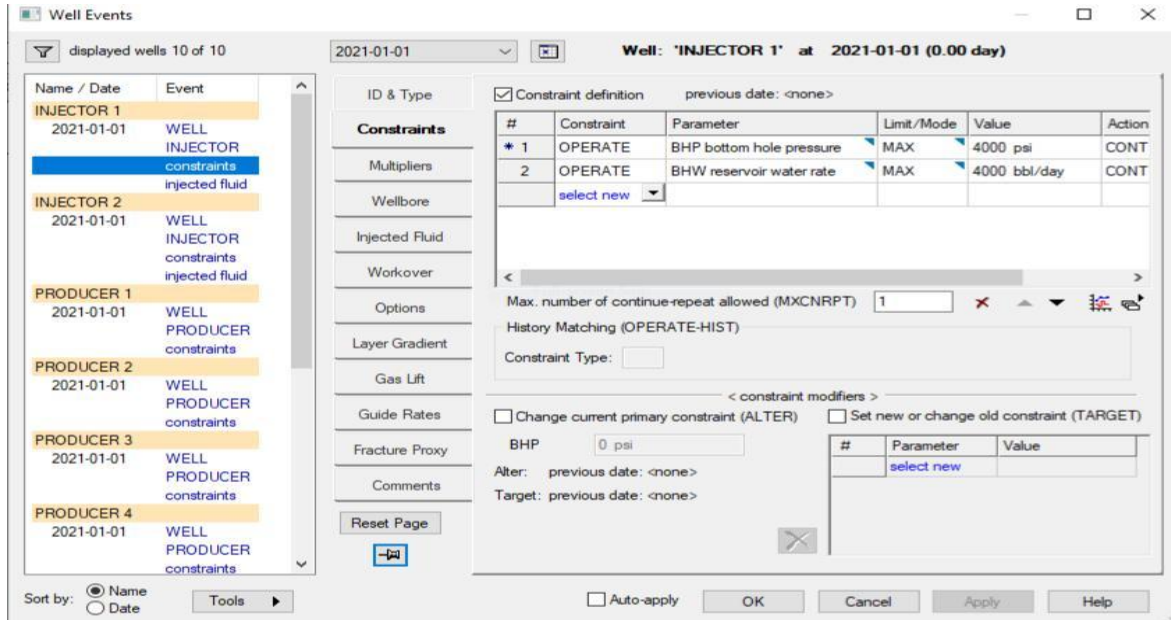


Figure 3-9: Illustration Showing Injection Well Constraints.

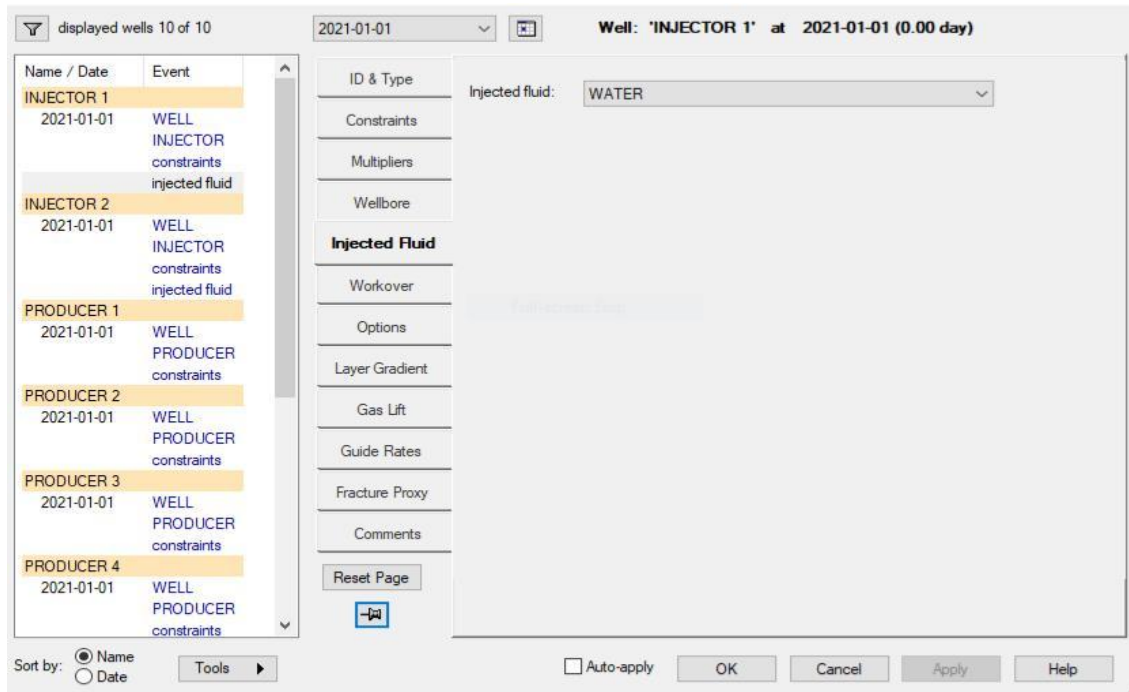


Figure 3-10: Illustrating the Injected Fluid (Water) Present within the Injector Well.

### 3.3.2 Case 2: Polymer Flooding

A polymer flooding model was created using the CMG Process Wizard to increase the effectiveness of the waterflooding process in this instance. In order to improve the injection fluid's viscosity and sweep efficiency, a polymer was added to it. The same set of injector wells were used in this instance. The same reservoir system was used for the simulation, and the outcomes were recorded and examined to see how oil recovery had improved.

During the setup, the following actions were taken:

- The CMG Process Wizard has eight (8) steps for setting up the polymer parameters.
- Decided on the start date of the injector wells: the polymer injection started on the very first day of the simulation.

- To assess performance, the simulation was run for each recovery scenario.

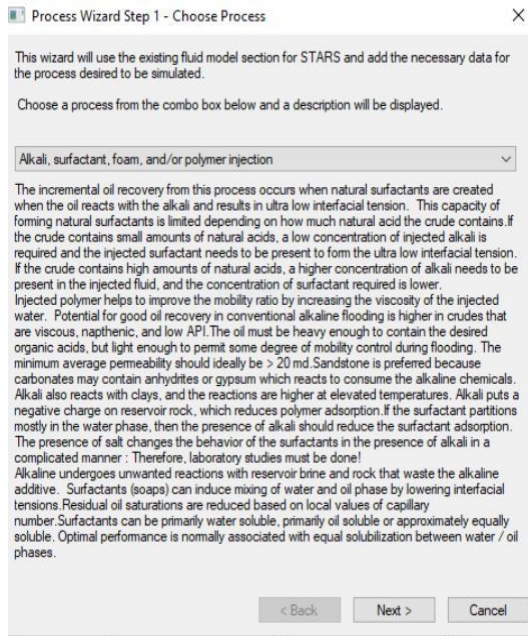


Figure 3-11: Select Process: Polymer Injection.

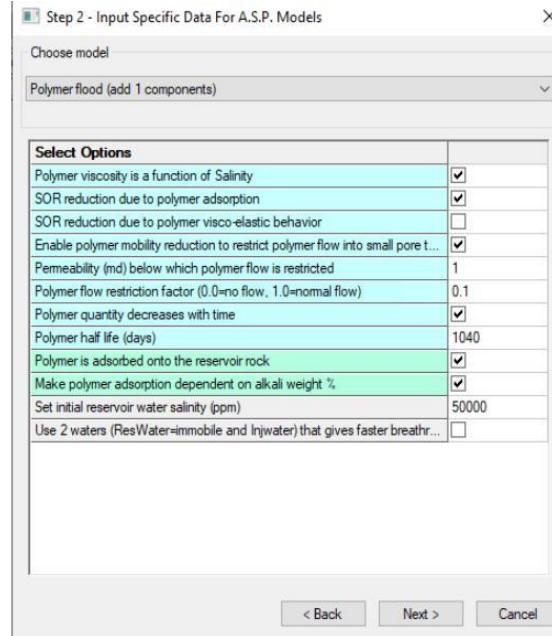


Figure 3-12: Design Polymer Model.

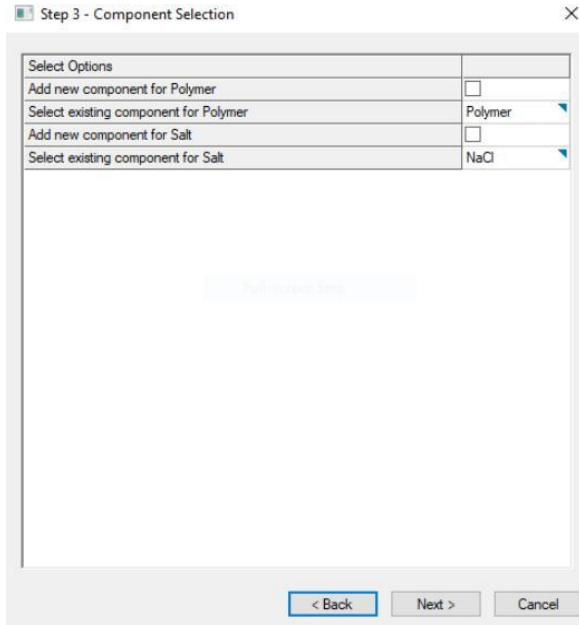


Figure 3-13: Component Selection for

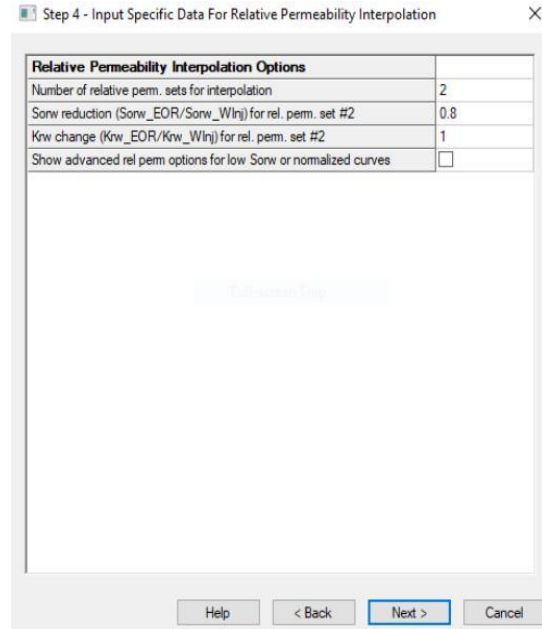
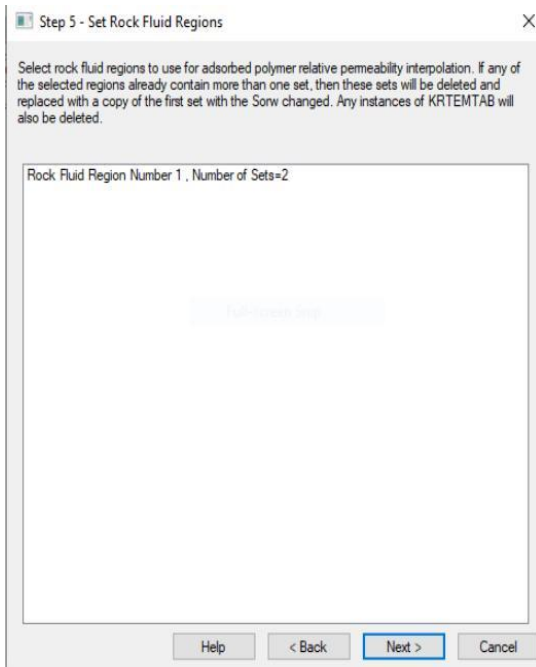
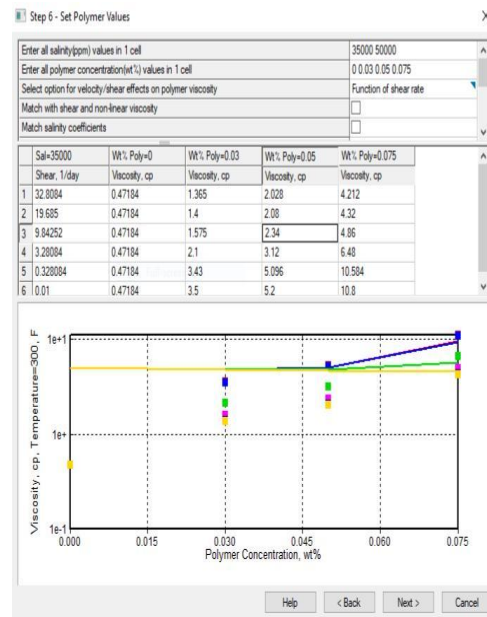


Figure 3-14: Input Specific Data for Relative



Polymer and Salt.

Figure 3-15: Setting up Rock Fluid Regions.



Permeability Interpolation.

Figure 3-16: Setting up Polymer Values.

Step 7 - Set Adsorption Values

Rock type for conversion of adsorption values (gm rock to PV)	Sandstone	
Rock Density, gm/cm <sup>3</sup>	2.65	
Enter all salinity(ppm) values in 1 cell	0 30000 60000	
<b>Polymer Adsorption</b>		
Polymer resistance factor (1.0=no permeability blockage)	1.3	
Accessible pore volume for polymer adsorption	0.9	
Enter porosity of laboratory polymer adsorption sample)	0.2494	
Number of polymer concentration vs. adsorption rows)	2	
	Weight % Polymer	Polymer Adsorption, mg/(100gm...
Salinity ppm Wt= 0	0	0
Salinity ppm Wt= 0	0.1	10
Salinity ppm Wt= 30000	0	0
Salinity ppm Wt= 30000	0.1	30
Salinity ppm Wt= 60000	0	0
Salinity ppm Wt= 60000	0.1	50

Buttons: Help, < Back, Next >, Cancel

Figure 3-17: Setting up Adsorption Values.

Step 8 - Choose Wells, Dates, and Set Injection Composition

<b>Aqueous Components for Water Injectors</b>	
Polymer injection wt%	0.075
Salt injection (ppm)	35000

Well Name	Date
<input checked="" type="checkbox"/> INJECTOR 1	2021-01-01 0:00:00
<input checked="" type="checkbox"/> INJECTOR 2	2021-01-01 0:00:00

Sort Well/Date Display:  
 Auto Select Wells:  
 ByName  ByDate  
 All  
 Producers  
 Injectors  
 Highlighted  
 Match name / wildcard

Buttons: Apply, < Back, Finish, Cancel

Figure 3-18: Choosing Wells, Dates and Setting Injection Composition.

### 3.3.3 Case 3: Steam injection

A steam injection in this case using CMG STARS for improved oil recovery, by reducing the viscosity of the heavy oil and improving its flow towards the production wells. To ensure optimal results, the reservoir model and well layout from previous cases were applied. To facilitate extraction of the trapped oil, and maximise overall displacement efficiency, steam was employed as the injection fluid driving heat and power into the reservoir.

The above setup consists of the following:

- Specified steam injection temperature, quality, and rate in CMG Builder.

- Designate the beginning of injection for the injector wells, where all injector wells start injecting steam on the very first day of simulation.
- An optimisation analysis of temperature, pressure and oil production rate would be carried out to evaluate performance across different recovery cases.

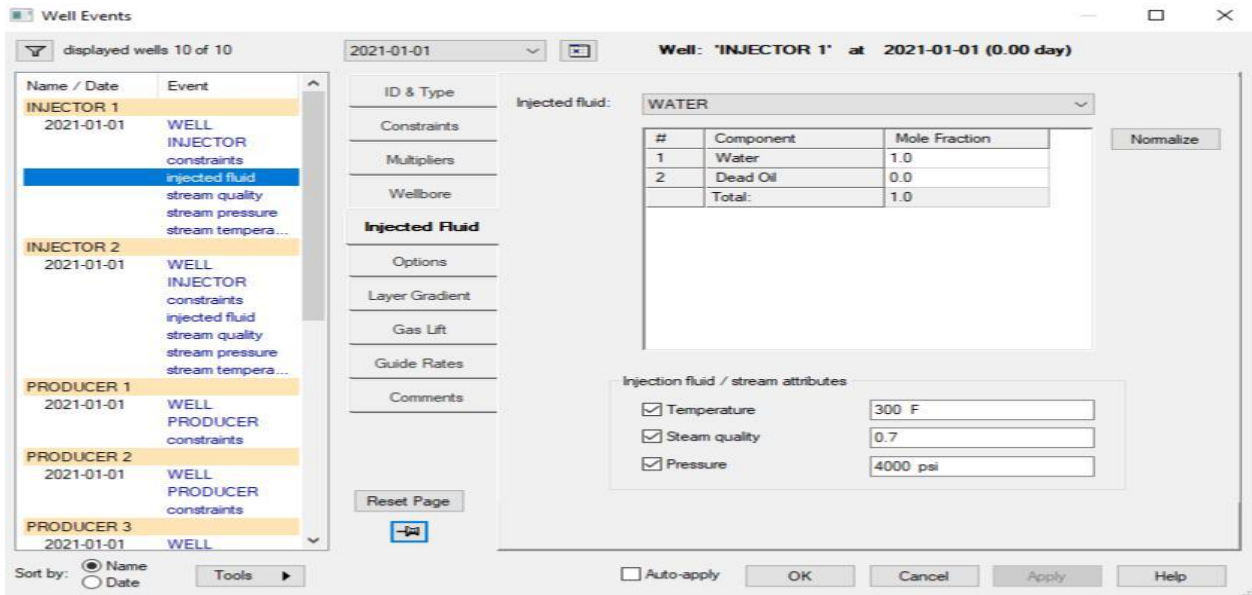


Figure 3-19: Illustrating the Injected Fluid (Water) and its Stream Attributes in the Injector Well.

To achieve optimal recovery, all three scenarios were carefully analysed and compared, allowing for data-driven adjustments to the injection parameters.

## CHAPTER 4

### RESULTS AND DISCUSSION

#### 4.1 Simulation Results and Graphs

This section contains the results and graphs obtained from the simulation process. Results from the simulation runs for waterflooding, steam injection and polymer flooding methods of Enhanced Oil Recovery have been presented in this chapter. CMG was employed for simulations to study the impacts of each method on in-situ oil recovery from the reservoir. The results are to be shown in tables and on graphs, so that production performance and the recovery evolution along time could be observed. Finally, optimisation of injection parameters were done in order to achieve the best operating conditions that would provide greatest oil recovery. The reservoir after simulation was observed to have the following initial composition before recovery took place, these values were observed:

- Total oil in place: This indicates the total volume of oil initially found in the reservoir before any extraction, which was about  $0.21749\text{E}+07$  STB or 2,174, 900 Stock Tank Barrels (STB).
- Total water in place: This signifies the total quantity of formation water initially contained within the reservoir. It's measured at  $0.85830\text{E}+07$  STB or 8,583,000 Stock Tank Barrels (STB).

- Total gas in place: This is the total amount of natural gas originally present in the reservoir. The value is given as 0.83172E+09 SCF or 831,720, 000 Standard Cubic Feet (SCF).

ITEM	UNIT	VALUE
Total Oil in Place	STB	0.21749E+07
Total Water in Place	STB	0.85830E+07
Total Gas in Place	SCF	0.83172E+09
Total Polymer in Place	LBM	0
HC Pore Volume	M RBBL	2634.5
Total Pore Volume	M RBBL	3512.6

**NB:** To simulate mature field conditions, a consistent time frame spanning of 10 years, from 2021 to 2031, was employed across all recovery scenarios investigated in this study.

*Table 4-1: Table Showing the Initial Fluid in Place Before Recovery is Simulated.*

#### **4.1.1 Case 1: Recovery from Water Injection (Waterflooding)**

In this case, water injection is simulated to help maintain the reservoir pressure and improve oil recovery. The main aim is to increase the areal sweep efficiency and push the remaining oil towards the production wells. The simulation is carried out using CMG-IMEX, and the results are analyzed to assess the enhancement of recovery by the water injection. In order to understand the performance of this process throughout the production period, cumulative oil production, water cut and reservoir pressure behavior were studied.

#### **4.1.1.a Simulation Setup (Waterflooding)**

The CMG Builder model developed for this simulation simulated a black oil reservoir system. Eight producer wells and two injector wells were located to ensure good areal sweep. To assist in reservoir pressure maintenance, water was used as the injecting fluid and injection of the water then started on the third year during simulation. To monitor the long-term performance of the reservoir, the simulation was run upto a cumulative production of 10 years.

#### **4.1.1.b Parameter Variation for Optimisation (Waterflooding)**

A total of nine (9) runs were performed under different well constraints to optimise the injection rate and injection pressure of the injector wells for better recovery. A summary of the simulation runs and the parameters used is shown in the table below;

Table 4-2: Summary of Waterflooding Simulation Runs, Parameter Variations and Results.

The oil recovery, water cut, and cumulative oil production shown in the table above were calculated from the point where the oil rate started to decline sharply, but the wells were still producing a reasonable amount of oil. This period was chosen so that a more meaningful assessment of the reservoir performance under each injection scenario could be made.

**4.1.1.c Simulation Results (Waterflooding)**

The simulation results for the waterflooding runs were analysed to evaluate the effect of

<b>Run No.</b>	<b>Injection Rate (bbl/day)</b>	<b>Injection Pressure (psia)</b>	<b>Oil Recovery Factor (%)</b>	<b>Water Cut (%)</b>	<b>Cumulative Oil Produced (MSTB)</b>
1	2000	2000	36.66	41.27	797.41
2	2000	2500	36.66	41.28	797.40
3	2000	3000	36.67	41.28	797.62
4	3000	2000	35.06	51.65	762.66
5	3000	2500	35.06	51.65	762.69
6	3000	3000	35.06	51.65	762.66
7	4000	2000	29.59	51.14	643.70
8	4000	2500	29.59	51.14	643.70
9	4000	3000	29.59	51.14	643.67

optimising the injector wells’ injection rate and injection pressure on oil recovery. From the

results, it was observed that changes in these parameters significantly influenced the reservoir performance. Generally, lower injection rates and higher pressures improved the recovery factor up to an optimal point, beyond which there was little or no further improvement.

The cumulative oil produced increased steadily with time, while the oil production rate declined gradually as the reservoir pressure decreased. Water cut increased towards the later stages of production, indicating more water breakthrough in the production wells. Overall, the simulation results show that the optimisation of the injection parameters had a positive impact on oil recovery.

The cumulative oil produced, water cut, and recovery factor for each of the different simulation runs are shown graphically in the figures below. The optimal injection rate and injection pressure combination that produced the best recovery performance was determined using these graphs.

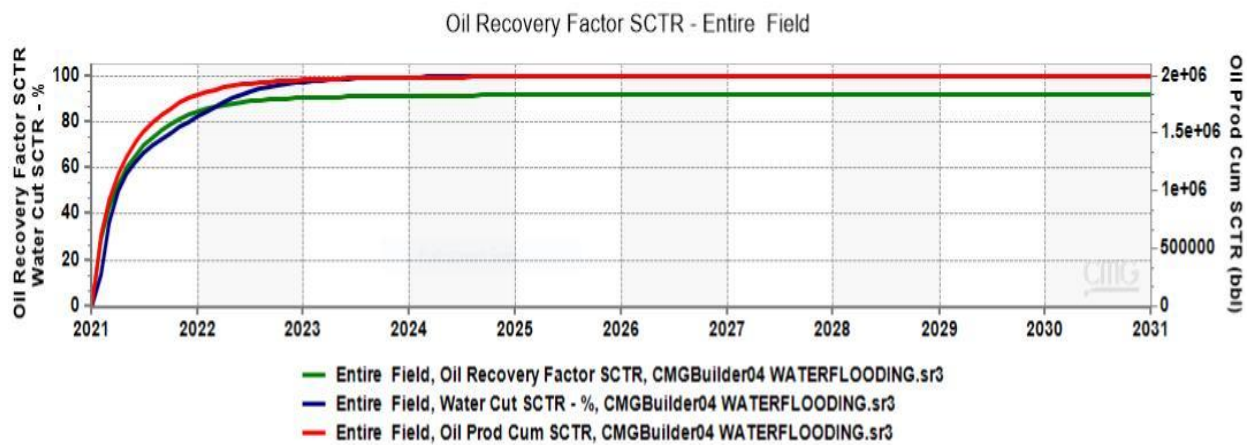
## RUN 1

Injection Rate = 2000 bbl/day    Injection Pressure = 2000 psi

Field Total	Fluid					
	Oil	Gas	Water	Solvent	Polymer	Salt
	(MSTB)	(MMSCF)	(MSTB)	(MMSCF)	(MLB)	(MLB)
Cumulative Production	1963.1	805.02	29044	NA	NA	NA
Cumulative Injection	NA	0	28516	NA	NA	NA
Cumulative Gas Lift	NA	0	NA	NA	NA	NA
Cumulative Aquifer Influx	NA	NA	0	NA	NA	NA
Current Fluids In Place	211.92	27.961	330.88	NA	NA	NA
Production Rates	.00146	325e-6	7.8058	NA	NA	NA
Injection Rates	NA	0	7.8066	NA	NA	NA
Timesteps: 140 Newton Cycles: 205 Cuts: 2 Solver Iterations: 1676						
Average Implicitness : 0.813						
Fluid Component Model : BLACKOIL (SINGLE-P)						
Material Balances (owg): 1.000 1.000 0.969						
Average Active Blocks: 6000 Average Non-BHP Active Wells: 2						
Total Blocks : 6000 Total Wells : 10						
Active Blocks: 6000 Non-BHP Active Wells: 2						
Time at end of simulation: 3652.00 (days)						
Average reservoir pressure excluding water zone: 486.9536 (psi)						
Total Number of Solver Failures: 0 Stalls: 0 ITERMAX Reached: 0						

Figure 4-1: Presents the Summary of Results Obtained from Run 1 of the Waterflooding Process.

Figure 4-2: Combined Plot of Oil Recovery Factor, Water Cut, and Cumulative Oil Production with Time During the Waterflooding Process for Run 1.



## RUN 2

Injection Rate = 2000 bbl/day. Injection Pressure = 2500 psi

Field Total	Fluid					
	Oil	Gas	Water	Solvent	Polymer	Salt
	(MSTB)	(MMSCF)	(MSTB)	(MMSCF)	(MLB)	(MLB)
Cumulative Production	1963.0	805.02	29044	NA	NA	NA
Cumulative Injection	NA	0	28516	NA	NA	NA
Cumulative Gas Lift	NA	0	NA	NA	NA	NA
Cumulative Aquifer Influx	NA	NA	0	NA	NA	NA
Current Fluids In Place	211.92	27.561	330.88	NA	NA	NA
Production Rates	.00146	325e-6	7.8058	NA	NA	NA
Injection Rates	NA	0	7.8066	NA	NA	NA

Timesteps: 140 Newton Cycles: 205 Cuts: 2 Solver Iterations: 1676  
 Average Implicitness : 0.813  
 Fluid Component Model : BLACKOIL (SINGLE-P)  
 Material Balances (owg): 1.000 1.000 0.969  
 Average Active Blocks: 6000 Average Non-BHP Active Wells: 2  
 Total Blocks : 6000 Total Wells : 10  
 Active Blocks: 6000 Non-BHP Active Wells: 2  
 Time at end of simulation: 3652.00 (days)  
 Average reservoir pressure excluding water zone: 486.9536 (psi)  
 Total Number of Solver Failures: 0 Stalls: 0 ITERMAX Reached: 0

Figure 4-3: Presents the Summary of Results Obtained from Run 2 of the Waterflooding Process.

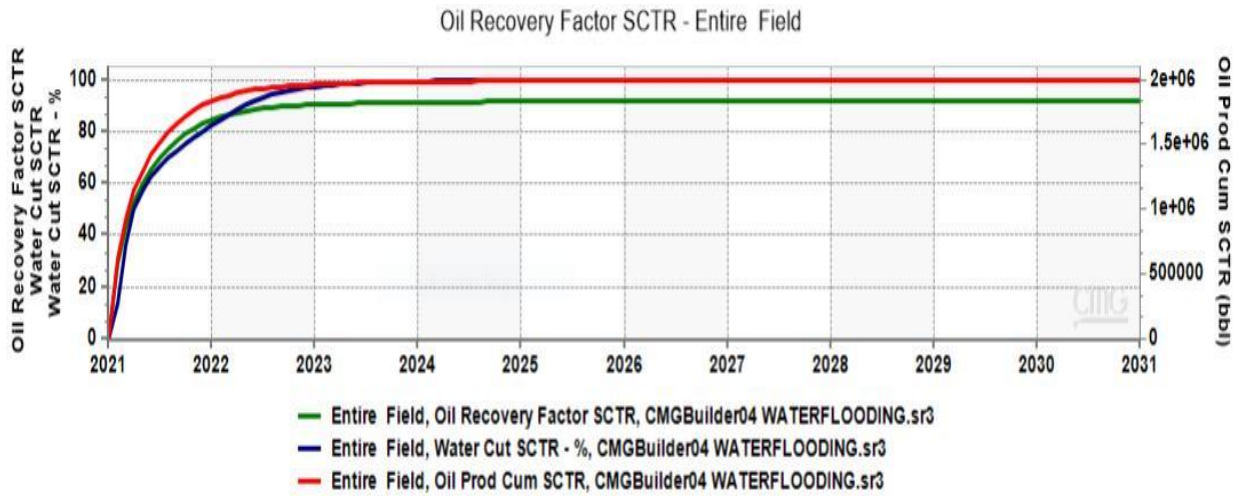


Figure 4-4: Combined Plot of Oil Recovery Factor, Water Cut, and Cumulative Oil Production with Time During the Waterflooding Process for Run 2.

### RUN 3

Injection Rate = 2000 bbl/day. Injection Pressure = 3000 psi.

Field Total	Fluid					
	Oil	Gas	Water	Solvent	Polymer	Salt
	(MSTB)	(MMSCF)	(MSTB)	(MMSCF)	(MLB)	(MLB)
Cumulative Production	1963.1	805.02	29043	NA	NA	NA
Cumulative Injection	NA	0	28516	NA	NA	NA
Cumulative Gas Lift	NA	0	NA	NA	NA	NA
Cumulative Aquifer Influx	NA	NA	0	NA	NA	NA
Current Fluids In Place	211.92	27.561	330.88	NA	NA	NA
Production Rates	.00146	325e-6	7.8058	NA	NA	NA
Injection Rates	NA	0	7.8066	NA	NA	NA

Timesteps: 140 Newton Cycles: 206 Cuts: 2 Solver Iterations: 1679  
 Average Implicitness : 0.811  
 Fluid Component Model : BLACKOIL (SINGLE-P)  
 Material Balances (owg): 1.000 1.000 0.969  
 Average Active Blocks: 6000 Average Non-BHP Active Wells: 2  
 Total Blocks : 6000 Total Wells : 10  
 Active Blocks: 6000 Non-BHP Active Wells: 2  
 Time at end of simulation: 3652.00 (days)  
 Average reservoir pressure excluding water zone: 486.9536 (psi)  
 Total Number of Solver Failures: 0 Stalls: 0 ITERMAX Reached: 0

Figure 4-5: Presents the Summary of Results Obtained from Run 3 of the Waterflooding Process.

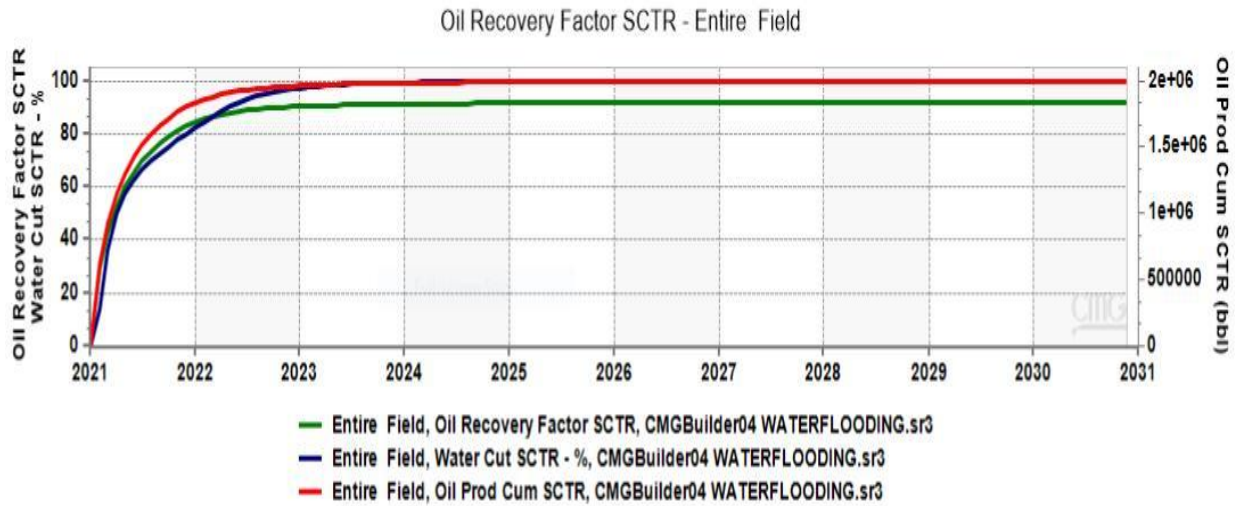


Figure 4-6: Combined Plot of Oil Recovery Factor, Water Cut, and Cumulative Oil Production with Time During the Waterflooding Process for Run 3.

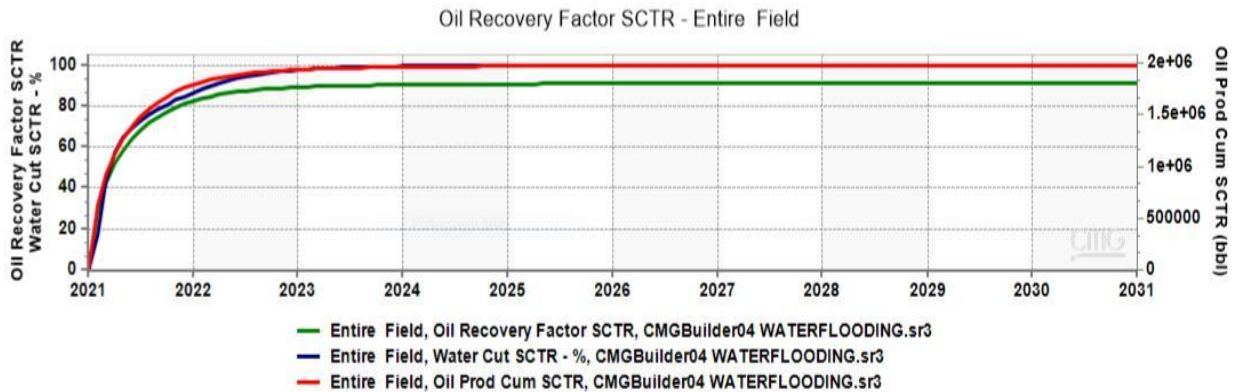
## RUN 4

Injection Rate = 3000 bbl/day. Injection Pressure = 2000 psi.

Field Total	Fluid					
	Oil	Gas	Water	Solvent	Polymer	Salt
	(MSTB)	(MMSCF)	(MSTB)	(MMSCF)	(MLB)	(MLB)
Cumulative Production	1914.1	787.30	43253	NA	NA	NA
Cumulative Injection	NA	0	42810	NA	NA	NA
Cumulative Gas Lift	NA	0	NA	NA	NA	NA
Cumulative Aquifer Influx	NA	NA	0	NA	NA	NA
Current Fluids In Place	260.55	45.260	415.06	NA	NA	NA
Production Rates	.00188	590e-6	11.720	NA	NA	NA
Injection Rates	NA	0	11.720	NA	NA	NA

Timesteps: 142 Newton Cycles: 200 Cuts: 2 Solver Iterations: 1516  
 Average Implicitness : 0.802  
 Fluid Component Model : BLACKOIL (SINGLE-P)  
 Material Balances (owg): 1.001 0.999 0.981  
 Average Active Blocks: 6000 Average Non-BHP Active Wells: 2  
 Total Blocks : 6000 Total Wells : 10  
 Active Blocks: 6000 Non-BHP Active Wells: 2  
 Time at end of simulation: 3652.00 (days)  
 Average reservoir pressure excluding water zone: 628.9765 (psi)  
 Total Number of Solver Failures: 0 Stalls: 0 ITERMAX Reached: 0

Figure 4-7: Presents the Summary of Results Obtained from Run 4 of the Waterflooding



Process.

Figure 4-8: Combined Plot of Oil Recovery Factor, Water Cut, and Cumulative Oil Production with Time During the Waterflooding Process for Run 4.

# RUN 5

Field Total	Fluid					
	Oil	Gas	Water	Solvent	Polymer	Salt
	(MSTB)	(MMSCF)	(MSTB)	(MMSCF)	(MLB)	(MLB)
Cumulative Production	1914.1	787.30	43253	NA	NA	NA
Cumulative Injection	NA	0	42810	NA	NA	NA
Cumulative Gas Lift	NA	0	NA	NA	NA	NA
Cumulative Aquifer Influx	NA	NA	0	NA	NA	NA
Current Fluids In Place	260.55	45.260	415.06	NA	NA	NA
Production Rates	.00188	590e-6	11.720	NA	NA	NA
Injection Rates	NA	0	11.720	NA	NA	NA

Timesteps: 142 Newton Cycles: 200 Cuts: 2 Solver Iterations: 1516  
 Average Implicitness : 0.802  
 Fluid Component Model : BLACKOIL (SINGLE-P)  
 Material Balances (owg): 1.001 0.999 0.981  
 Average Active Blocks: 6000 Average Non-BHP Active Wells: 2  
 Total Blocks : 6000 Total Wells : 10  
 Active Blocks: 6000 Non-BHP Active Wells: 2  
 Time at end of simulation: 3652.00 (days)  
 Average reservoir pressure excluding water zone: 628.9765 (psi)  
 Total Number of Solver Failures: 0 Stalls: 0 ITERMAX Reached: 0

Injection Rate = 3000 bbl/day. Injection Pressure = 2500 psi.

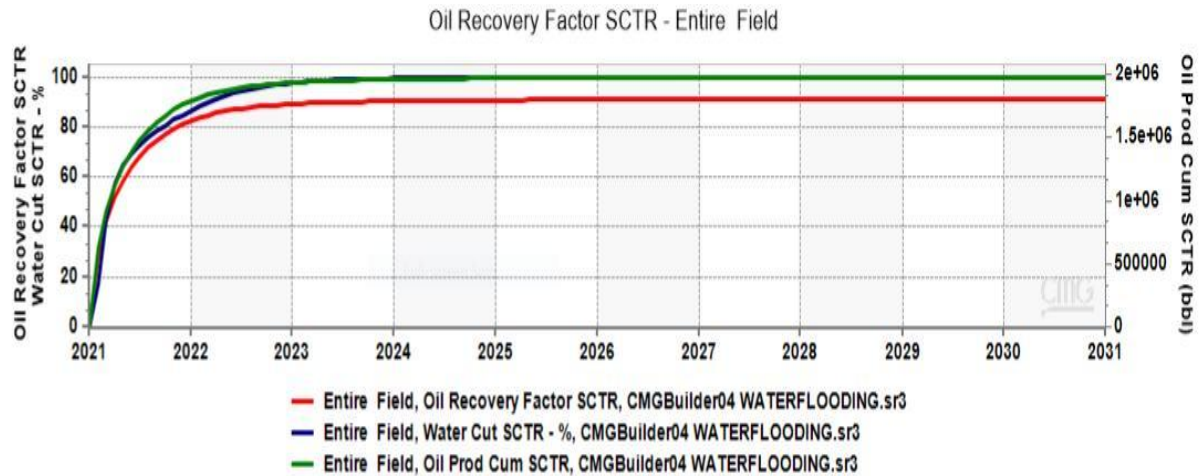


Figure 4-9: Presents the Summary of Results Obtained from Run 5 of the Waterflooding Process.

Figure 4-10: Combined Plot of Oil Recovery Factor, Water Cut, and Cumulative Oil Production with Time During the Waterflooding Process for Run

# RUN 6

Field Total	Fluid					
	Oil	Gas	Water	Solvent	Polymer	Salt
	(MSTB)	(MMSCF)	(MSTB)	(MMSCF)	(MLB)	(MLB)
Cumulative Production	1914.1	787.30	43253	NA	NA	NA
Cumulative Injection	NA	0	42810	NA	NA	NA
Cumulative Gas Lift	NA	0	NA	NA	NA	NA
Cumulative Aquifer Influx	NA	NA	0	NA	NA	NA
Current Fluids In Place	260.55	45.260	415.06	NA	NA	NA
Production Rates	.00188	590e-6	11.720	NA	NA	NA
Injection Rates	NA	0	11.720	NA	NA	NA

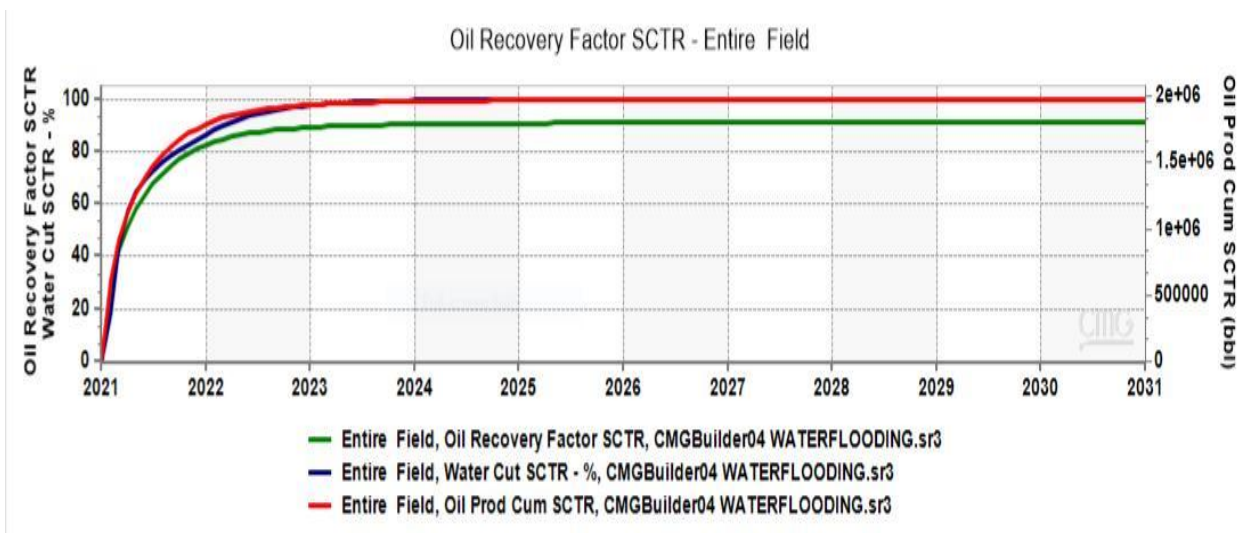
  

Timesteps: 142 Newton Cycles: 200 Cuts: 2 Solver Iterations: 1516  
 Average Implicitness : 0.802  
 Fluid Component Model : BLACKOIL (SINGLE-P)  
 Material Balances (owg): 1.001 0.999 0.981  
 Average Active Blocks: 6000 Average Non-BHP Active Wells: 2  
 Total Blocks : 6000 Total Wells : 10  
 Active Blocks: 6000 Non-BHP Active Wells: 2  
 Time at end of simulation: 3652.00 (days)  
 Average reservoir pressure excluding water zone: 628.9765 (psi)  
 Total Number of Solver Failures: 0 Stalls: 0 ITERMAX Reached: 0

Injection Rate = 3000 bbl/day. Injection Pressure = 3000 psi.

Figure 4-11: Presents the Summary of Results Obtained from Run 6 of the Waterflooding Process.

Figure 4-12: Combined Plot of Oil Recovery Factor, Water Cut, and Cumulative Oil Production with Time During the Waterflooding Process for Run 6.



## RUN 7

Injection Rate = 4000 bbl/day. Injection Pressure = 2000 psi.

Field Total	Fluid					
	Oil	Gas	Water	Solvent	Polymer	Salt
	(MSTB)	(MMSCF)	(MSTB)	(MMSCF)	(MLB)	(MLB)
Cumulative Production	1853.3	762.19	57451	NA	NA	NA
Cumulative Injection	NA	0	57113	NA	NA	NA
Cumulative Gas Lift	NA	0	NA	NA	NA	NA
Cumulative Aquifer Influx	NA	NA	0	NA	NA	NA
Current Fluids In Place	321.14	70.215	521.43	NA	NA	NA
Production Rates	.00246	967e-6	15.637	NA	NA	NA
Injection Rates	NA	0	15.636	NA	NA	NA

Timesteps:	144	Newton Cycles:	200	Cuts:	2	Solver Iterations:	1494
Average Implicitness	: 0.797						
Fluid Component Model	: BLACKOIL (SINGLE-P)						
Material Balances (owg):	1.002 0.998 0.990						
Average Active Blocks:	6000	Average Non-BHP Active Wells:	2				
Total Blocks :	6000	Total Wells :	10				
Active Blocks:	6000	Non-BHP Active Wells:	2				
Time at end of simulation:	3652.00 (days)						
Average reservoir pressure excluding water zone:	774.3138 (psi)						
Total Number of Solver Failures:	0	Stalls:	0	ITERMAX Reached:	0		

Figure 4-13: Presents the Summary of Results Obtained from Run 7 of the Waterflooding Process.

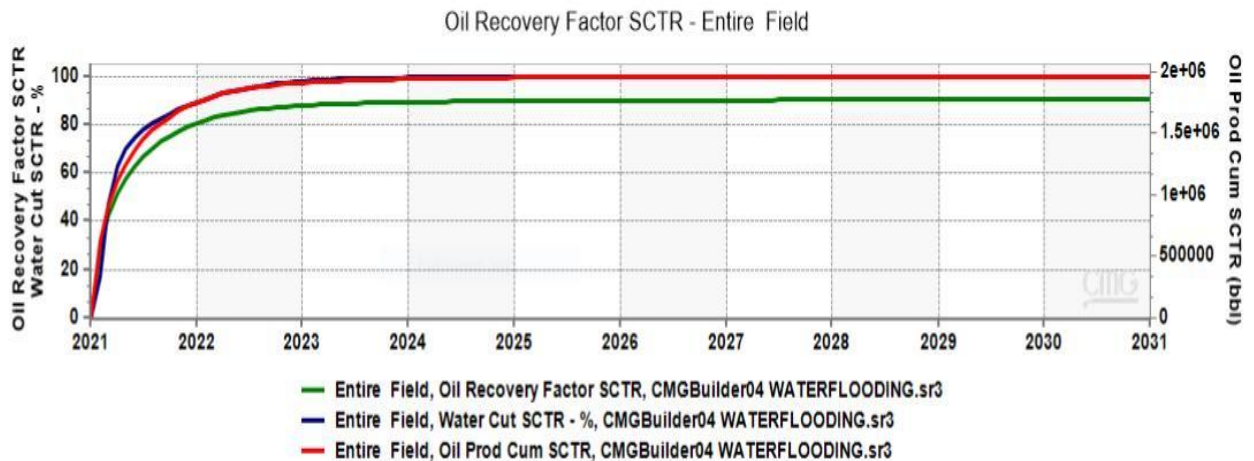


Figure 4-14: Combined Plot of Oil Recovery Factor, Water Cut, and Cumulative Oil Production with Time During the Waterflooding Process for Run 7.

## RUN 8

Injection Rate = 4000 bbl/day. Injection Pressure = 2500 psi.

Field Total	Fluid					
	Oil	Gas	Water	Solvent	Polymer	Salt
	(MSTB)	(MMSCF)	(MSTB)	(MMSCF)	(MLB)	(MLB)
Cumulative Production	1853.3	762.19	57451	NA	NA	NA
Cumulative Injection	NA	0	57113	NA	NA	NA
Cumulative Gas Lift	NA	0	NA	NA	NA	NA
Cumulative Aquifer Influx	NA	NA	0	NA	NA	NA
Current Fluids In Place	321.14	70.215	521.43	NA	NA	NA
Production Rates	.00246	967e-6	15.637	NA	NA	NA
Injection Rates	NA	0	15.636	NA	NA	NA

Timesteps:	144	Newton Cycles:	200	Cuts:	2	Solver Iterations:	1494
Average Implicitness	: 0.797						
Fluid Component Model	: BLACKOIL (SINGLE-P)						
Material Balances (owg):	1.002 0.998 0.990						
Average Active Blocks:	6000	Average Non-BHP Active Wells:	2				
Total Blocks :	6000	Total Wells :	10				
Active Blocks:	6000	Non-BHP Active Wells:	2				
Time at end of simulation:	3652.00 (days)						
Average reservoir pressure excluding water zone:	774.3138 (psi)						
Total Number of Solver Failures:	0	Stalls:	0	ITERMAX Reached:	0		

Figure 4-15: Presents the Summary of Results Obtained from Run 8 of the Waterflooding Process.

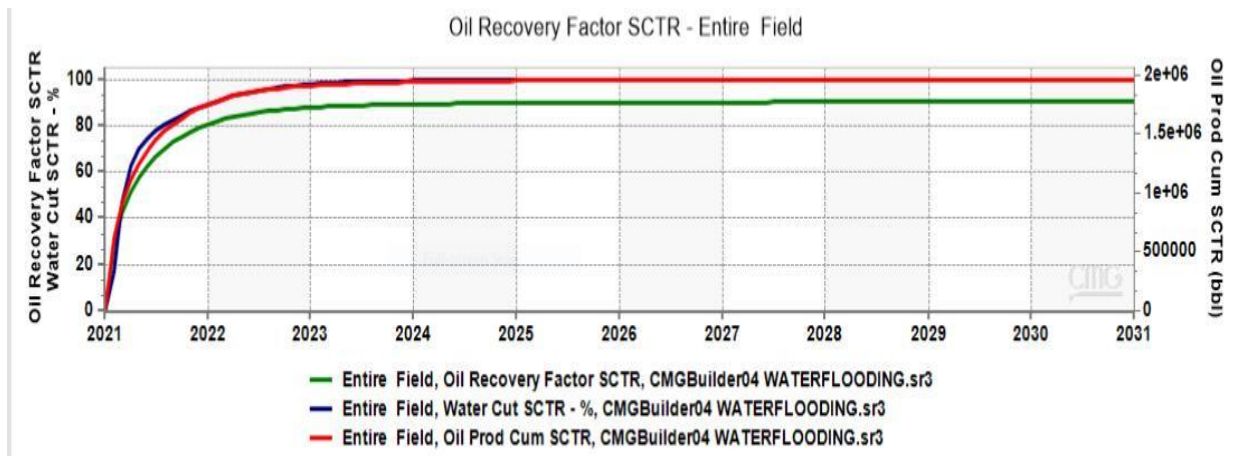


Figure 4-16: Combined Plot of Oil Recovery Factor, Water Cut, and Cumulative Oil Production with Time During the Waterflooding Process for Run 8.

# RUN 9

Field Total	Fluid					
	Oil	Gas	Water	Solvent	Polymer	Salt
	(MSTB)	(MMSCF)	(MSTB)	(MMSCF)	(MLB)	(MLB)
Cumulative Production	1853.3	762.19	57451	NA	NA	NA
Cumulative Injection	NA	0	57113	NA	NA	NA
Cumulative Gas Lift	NA	0	NA	NA	NA	NA
Cumulative Aquifer Influx	NA	NA	0	NA	NA	NA
Current Fluids In Place	321.14	70.215	521.43	NA	NA	NA
Production Rates	.00246	967e-6	15.637	NA	NA	NA
Injection Rates	NA	0	15.636	NA	NA	NA
Timesteps: 144 Newton Cycles: 200 Cuts: 2 Solver Iterations: 1494						
Average Implicitness : 0.797						
Fluid Component Model : BLACKOIL (SINGLE-P)						
Material Balances (owg): 1.002 0.998 0.990						
Average Active Blocks: 6000 Average Non-BHP Active Wells: 2						
Total Blocks : 6000 Total Wells : 10						
Active Blocks: 6000 Non-BHP Active Wells: 2						
Time at end of simulation: 3652.00 (days)						
Average reservoir pressure excluding water zone: 774.3138 (psi)						
Total Number of Solver Failures: 0 Stalls: 0 ITERMAX Reached: 0						

Injection Rate = 4000 bbl/day. Injection Pressure = 3000 psi.

Figure 4-17: Presents the Summary of Results Obtained from Run 9 of the Waterflooding Process.

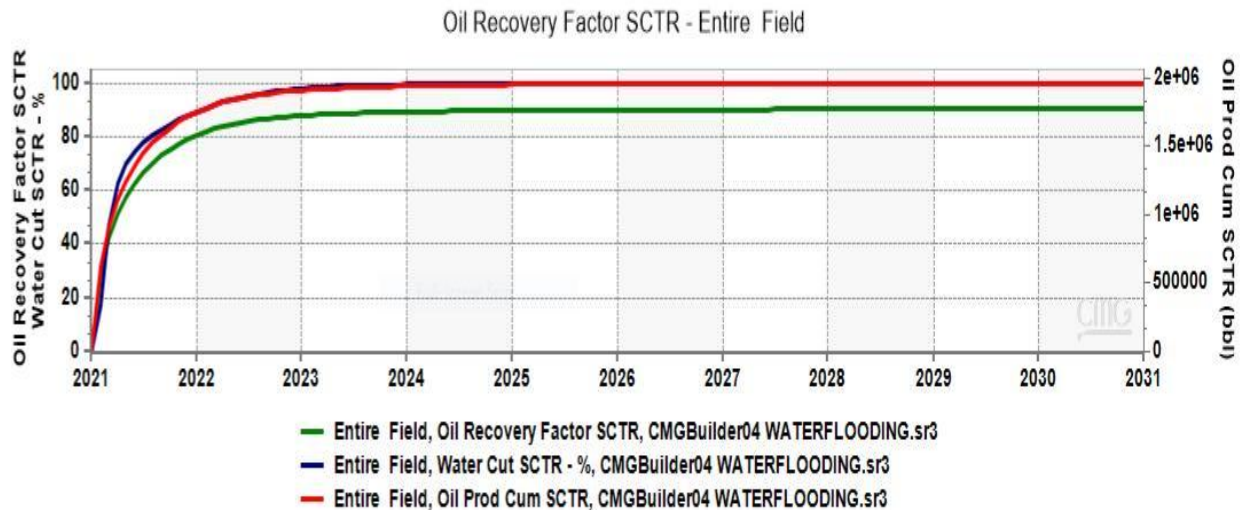


Figure 4-18: Combined Plot of Oil Recovery Factor, Water Cut, and Cumulative Oil Production with Time During the Waterflooding Process for Run 9.

#### **4.1.1.d Discussion of Results and Analysis (Waterflooding)**

##### **DISCUSSION OF RESULTS:**

The results of the waterflooding simulations clearly demonstrate how injection parameters impact the efficiency of oil recovery. The oil rate and oil cumulative production were also affected by variation in injection pressure and injection rate among the nine simulation runs.

Overall, the oil displacement efficiency and reservoir pressure maintenance were improved with decreasing the injection rate and increasing pressure, which in turn led to higher cumulative oil production and recovery factor.

However, it was also observed that at advanced stages of the simulation an excessive injection rate and pressure resulted in higher water production and water cut. This means that there can be an optimal tuning of the injection parameters to find a balance between the large costs of handling water cut and good oil recovery. The best run that resulted in maximum RF (Recovery Factor) and cumulative oil production, from nine different runs, will be selected as the best set up of the injection parameters.

##### **ANALYSIS OF RESULTS:**

When evaluating “best” performance for EOR (especially for waterflooding), we consider:

1. Highest Oil Recovery Factor (RF) (%).
2. Highest Cumulative Oil Produced (MSTB).

3. Lowest Water Cut (%), Since high water cut means more water production and less oil production.

Now, from Table 4-2 in previous section (4.1.1.b):

- Runs 1-3 clearly outperform the others.
  1. Oil Recovery Factor (RF): ~36.66-36.67%.
  2. Cumulative Oil Produced: ~797 MSTB.
  3. Water Cut: ~41% (lowest among all runs).

Among these three runs, Run 3 (Injection Rate = 2000 bbl/day, Injection Pressure = 3000 psi) gives the highest Recovery Factor (RF) (36.67%) and highest Cumulative Oil Produced (797.618 MSTB) even if just slightly.

Therefore, The best Run is:

**Run 3** – Injection Rate: 2000 bbl/day, Injection Pressure: 3000 psi.

**Reason:** it gives the highest Recovery Factor (RF) and Cumulative Oil Production with the lowest Water Cut, indicating an optimum balance between the injection rate and pressure.

#### **4.1.2 CASE 2: Recovery from Polymer Flooding**

In this case, oil production is enhanced while taking into account the level of efficiency already achieved by waterflooding through the addition of polymer. By reducing the water permeability, it is proposed to increase the sweep efficiency and improve the mobility ratio and thereby displace more oil towards production wells. A simulation using CMG-STARS is performed and

the results are examined to see if recovery has been enhanced by injecting the polymer solution. Cumulative oil production, water cut, and oil recovery factor are some parameters through which the performance of this process throughout the production period was studied.

#### **4.1.2.a Simulation Setup (Polymer Flooding)**

The CMG Builder model developed for this simulation represents a black oil reservoir system designed for polymer flooding. Eight producer wells and two injector wells were placed to achieve good areal coverage within the reservoir. In this case, a polymer solution was injected to enhance oil displacement efficiency and improve sweep performance by reducing water mobility. The injection of the polymer solution began on the fifth year of the simulation after two years of waterflooding to maintain reservoir pressure and improve recovery efficiency. The simulation was carried out for a total production period of 10 years to observe the long-term behaviour of the reservoir and evaluate the effectiveness of polymer flooding.

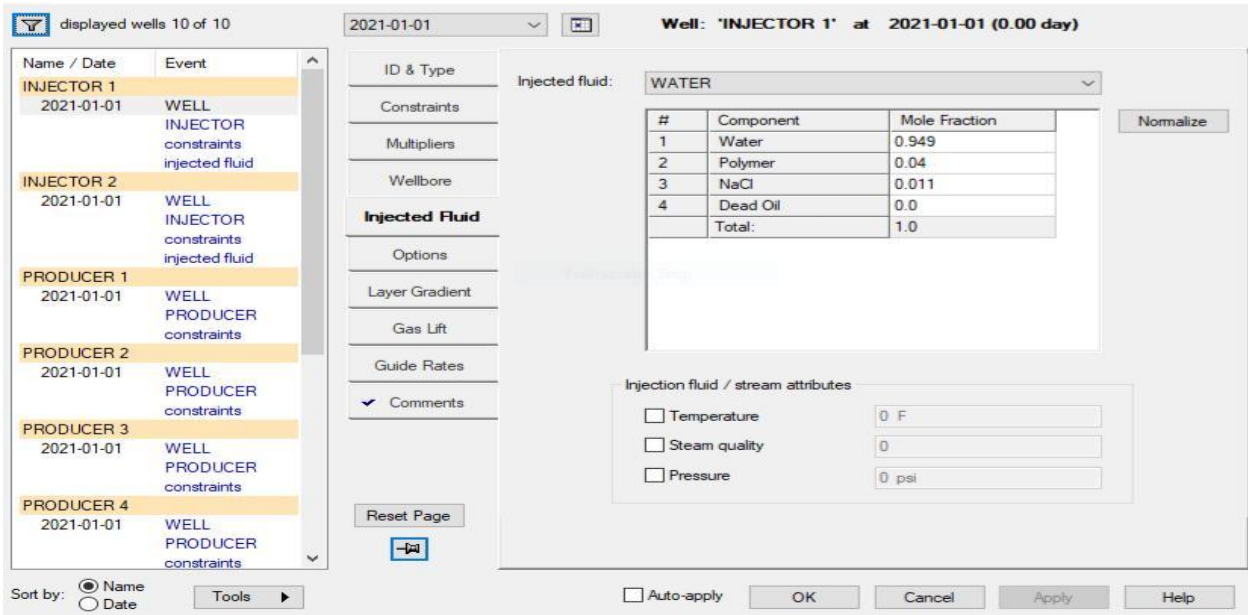


Figure 4-19: Shows the Configuration of the Injected Fluid Composition.

#### 4.1.2.b Parameter Variation for Optimisation (Polymer Flooding)

A total of nine (9) runs were performed under different well constraints to optimise the injection rate and injection pressure of the injector wells for better recovery. A summary of the simulation runs and the parameters used is shown below;

Run NO.	Injection Rate	Injection Pressure	Oil Recovery Factor (%)	Water Cut (%)	Cumulative Oil

	<b>(bbl/day)</b>	<b>(psi)</b>			<b>Produced (MSTB)</b>
1	2000	2000	48.43	59.80	1053.41
2	2000	2500	50.88	62.55	1106.70
3	2000	3000	52.29	64.60	1137.37
4	3000	2000	48.44	59.85	1053.73
5	3000	2500	50.74	62.29	1103.65
6	3000	3000	52.24	64.55	1136.28
7	4000	2000	48.46	59.90	1054.06
8	4000	2500	50.60	62.03	1100.60
9	4000	3000	52.05	64.34	1132.15

*Table 4-3: Summary of Polymer Flooding Simulation Runs, Parameter Variations and Results.*

The oil recovery, water cut, and cumulative oil production shown in the table above were calculated from the point where the oil rate started to decline sharply, but the wells were still producing a reasonable amount of oil. This period was chosen so that a more meaningful assessment of the reservoir performance under each injection scenario could be made.

#### **4.1.2.c Simulation Results (Polymer Flooding)**

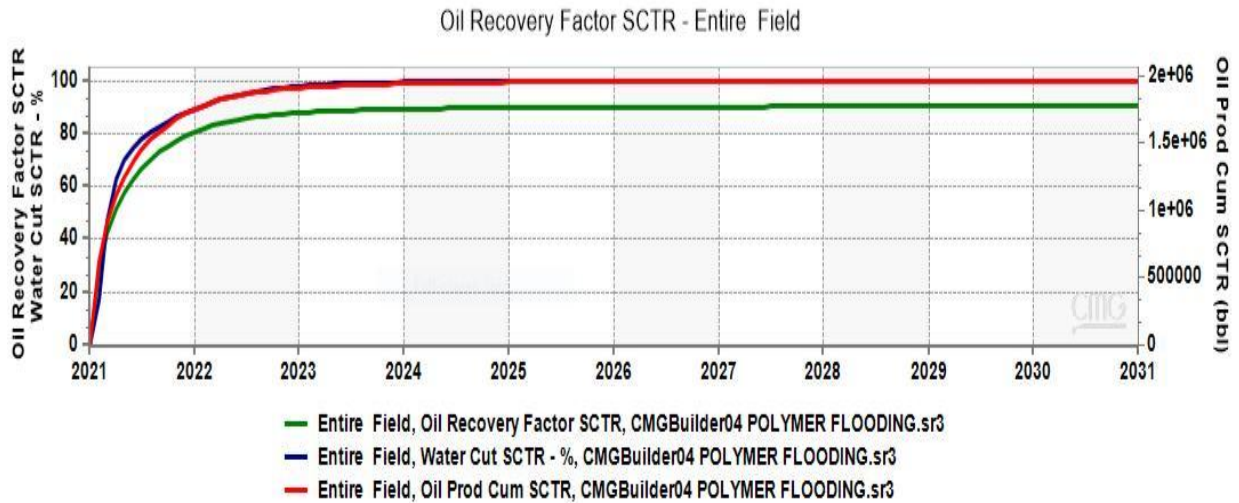
The simulation results for the polymer flooding runs were analysed to evaluate the effect of optimising the injector wells' injection rate and injection pressure on oil recovery. From the results, it was observed that changes in these parameters significantly influenced the reservoir

performance. Generally, lower injection rates and higher pressures improved the recovery factor up to an optimal point, beyond which there was little or no further improvement.

The cumulative oil produced increased steadily with time, while the oil production rate declined gradually as the reservoir pressure decreased. Water cut increased towards the later stages of production, indicating more water breakthrough in the production wells. Overall, the simulation results show that the optimisation of the injection parameters had a positive impact on oil recovery.

The cumulative oil produced, water cut, and recovery factor for each of the different simulation runs are shown graphically in the figures below. The optimal injection rate and injection pressure combination that produced the best recovery performance was determined using these graphs.

## **RUN 1**

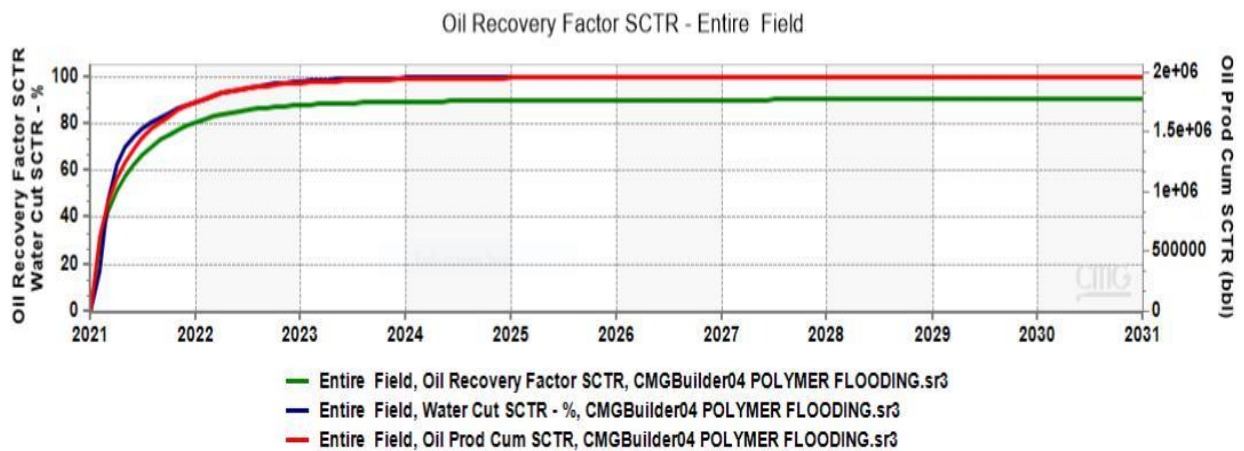


Injection Rate = 2000 bbl/day.

Injection Pressure = 2000 psi.

Figure 4-20: Combined Plot of Oil Recovery Factor, Water Cut, and Cumulative Oil Production with Time During the Polymer Flooding Process for Run 1.

## RUN 2

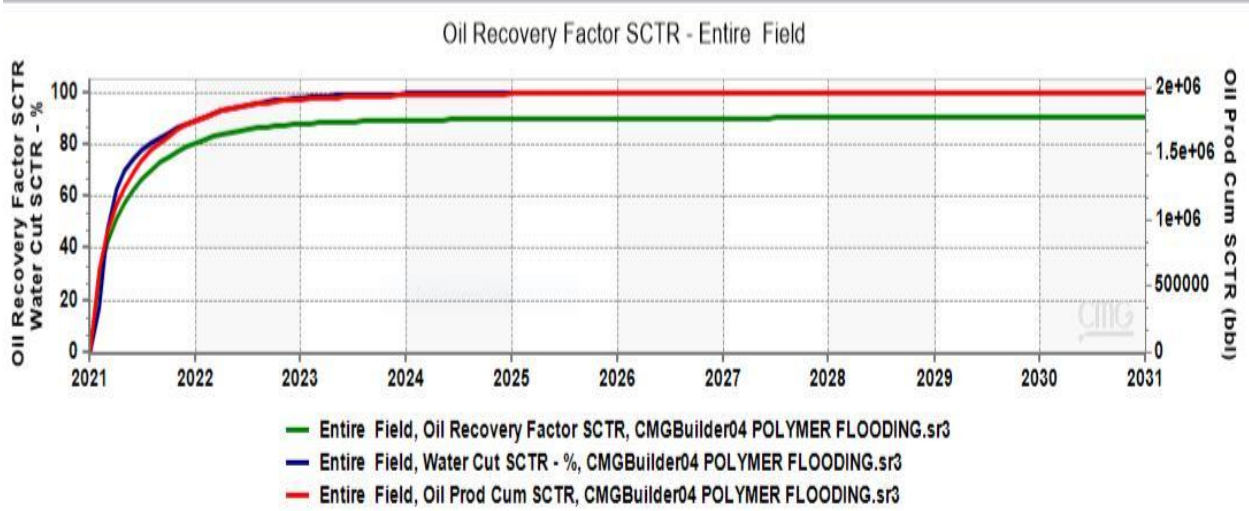


Injection Rate = 2000 bbl/day.

Injection Pressure = 2500 psi.

Figure 4-21: Combined Plot of Oil Recovery Factor, Water Cut, and Cumulative Oil Production with Time During the Polymer Flooding Process for Run 2.

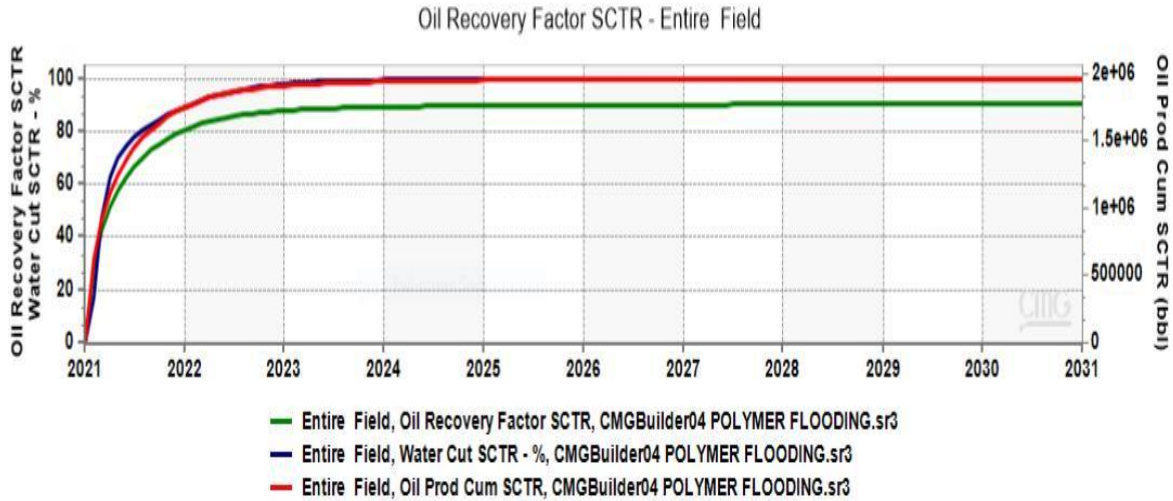
**RUN 3**



Injection Rate = 2000 bbl/day.      Injection Pressure = 3000 psi.

Figure 4-22: Combined Plot of Oil Recovery Factor, Water Cut, and Cumulative Oil Production with Time During the Polymer Flooding Process for Run 3.

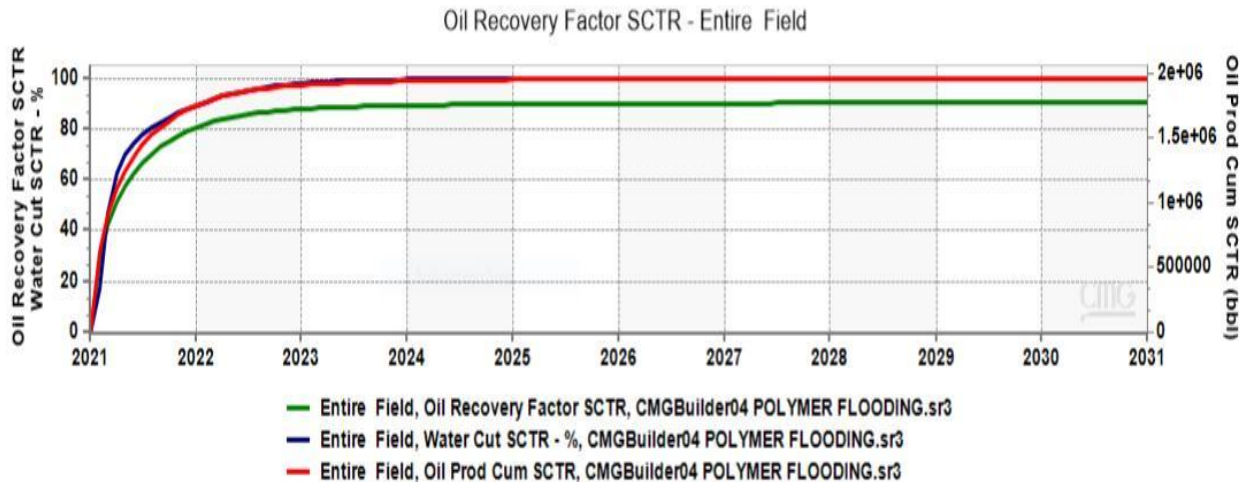
**RUN 4**



Injection Rate = 3000 bbl/day      Injection Pressure = 2000 psi

Figure 4-23: Combined Plot of Oil Recovery Factor, Water Cut, and Cumulative Oil Production with Time During the Polymer Flooding Process for Run 4.

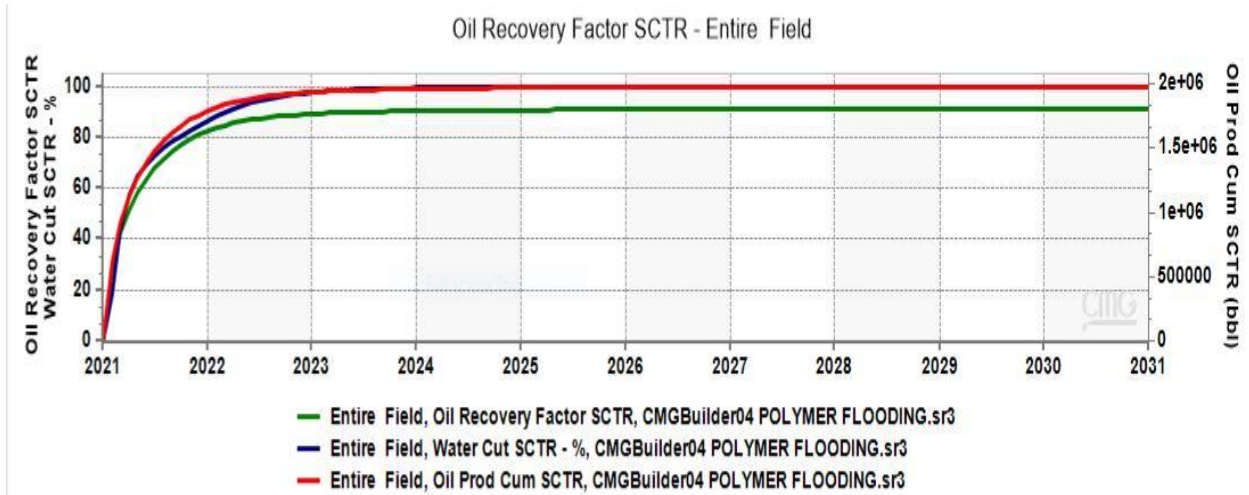
## RUN 5



Injection Rate = 3000 bbl/day.      Injection Pressure = 2500 psi.

Figure 4-24: Combined Plot of Oil Recovery Factor, Water Cut, and Cumulative Oil Production with Time During the Polymer Flooding Process for Run 5.

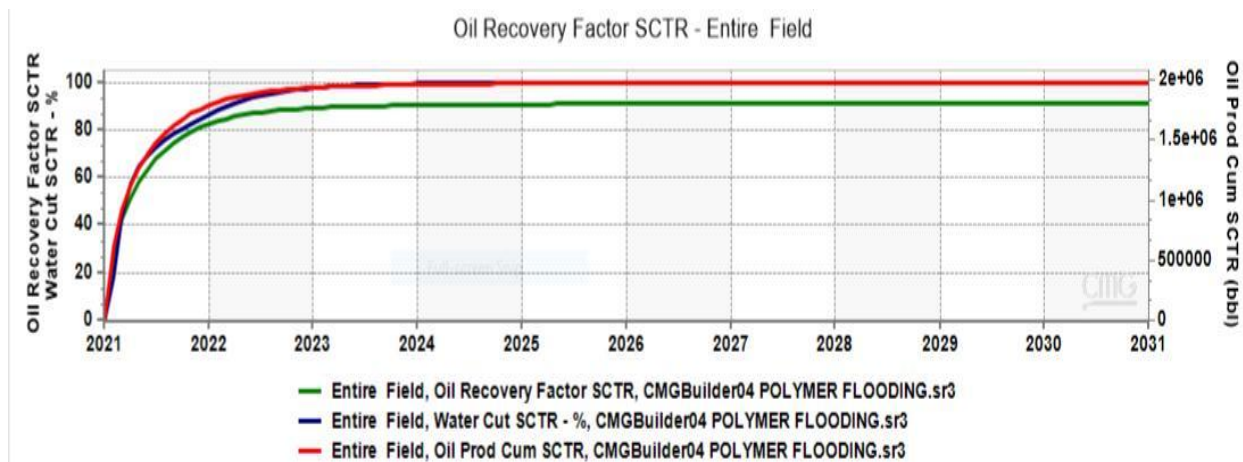
**RUN 6.**



Injection Rate = 3000 bbl/day. Injection Pressure = 3000 psi.

Figure 4-25: Combined Plot of Oil Recovery Factor, Water Cut, and Cumulative Oil Production with Time During the Polymer Flooding Process for Run 6.

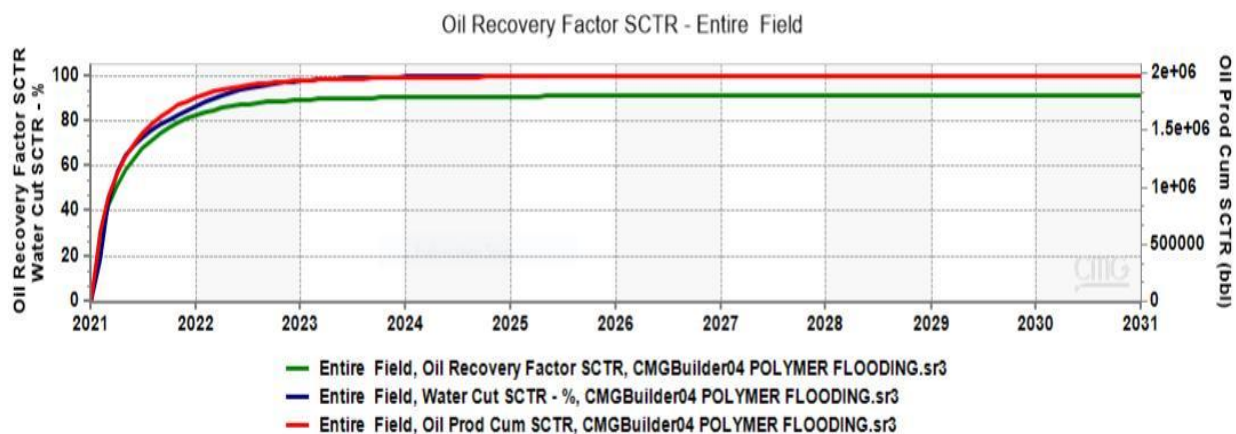
**RUN 7**



Injection Rate = .4000 bbl/day.      Injection Pressure = 2000 psi.

Figure 4-26: Combined Plot of Oil Recovery Factor, Water Cut, and Cumulative Oil Production with Time During the Polymer Flooding Process for Run 7.

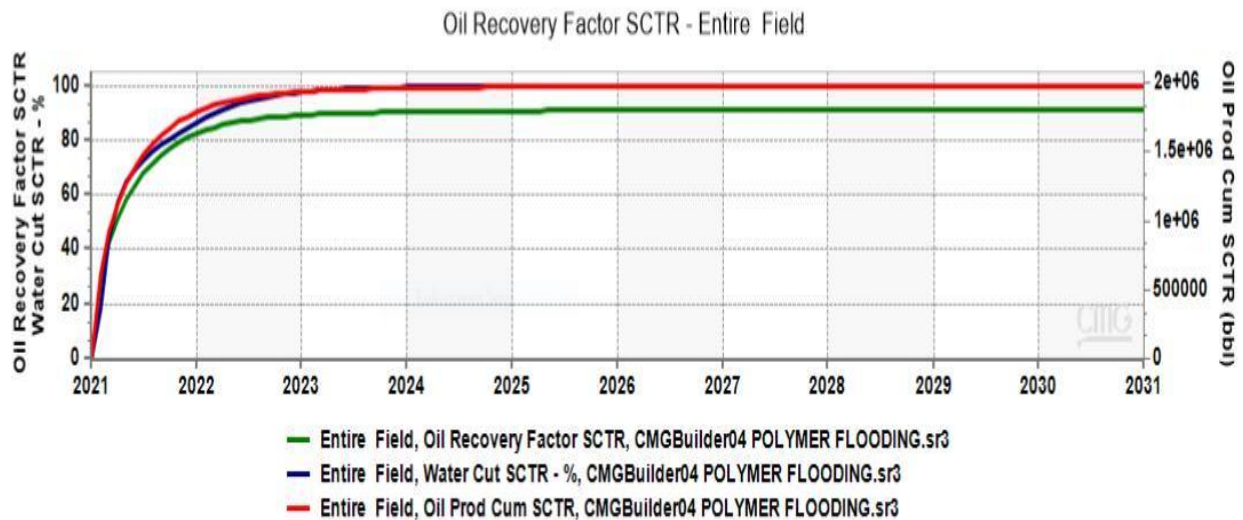
### RUN 8



Injection Rate = 4000 bbl/day.      Injection Pressure = 2500 psi.

Figure 4-27: Combined Plot of Oil Recovery Factor, Water Cut, and Cumulative Oil Production with Time During the Polymer Flooding Process for Run 8.

## RUN 9



Injection Rate = 4000 bbl/day.      Injection Pressure = 3000 psi.

*Figure 4-28: Combined Plot of Oil Recovery Factor, Water Cut, and Cumulative Oil Production with Time During the Polymer Flooding Process for Run 9.*

### 4.1.2.d Discussion of Results and Analysis (Polymer Flooding)

#### DISCUSSION OF RESULTS:

Variations in injection rate and pressure had a significant impact on oil recovery performance, according to the polymer flooding simulations. The recovery factor and cumulative oil production increased as a result of improved sweep efficiency and better reservoir pressure maintained by higher injection pressures and polymer concentrations.

However, it was also observed that at advanced stages of the simulation an excessive injection rate and pressure resulted in higher water production and water cut. This means that there can be an optimal tuning of the injection parameters to find a balance between the large costs of handling water cut and good oil recovery. The best run that resulted in maximum RF (Recovery Factor) and cumulative oil production, from nine different runs, will be selected as the best set up of the injection parameters.

### **ANALYSIS OF RESULTS:**

When evaluating the “best” performance for polymer flooding, the following factors are considered:

1. Highest Oil Recovery Factor (RF) (%).
2. Highest Cumulative Oil Produced (MSTB).
3. Lowest Water Cut (%), Since high water cut means more water production and less oil production.

Now, from Table 4-3 in previous section (4.1.2.b):

The best Run is;

**Run 3** – Injection Rate: 2000 bbl/day, Injection Pressure: 3000 psi.

### **Reasons:**

- It has the highest oil recovery factor (27.59%).
- It also gives the highest cumulative oil produced (407.888 MSTB).
- Though the water cut (61.23%) is slightly higher than Run 1 and 2, the overall oil recovery efficiency is better.

### **4.1.3 Case 3: Recovery from Steam Injection**

In this case, steam injection is simulated to enhance oil recovery by heating the reservoir and reducing the viscosity of the oil, thereby improving its mobility. The main aim is to increase the displacement efficiency and push the remaining oil towards the production wells through thermal stimulation. The simulation is carried out using CMG-STARs, and the results are analysed to assess the improvement in recovery achieved through steam injection. To evaluate the performance of this process over the production period, cumulative oil production, water cut, and reservoir pressure behaviour were closely studied.

#### **4.1.3.a Simulation Setup (Steam Injection)**

A black oil reservoir model (CMG Builder) was developed specifically for this simulation. Eight producer wells and two injector wells were located to ensure sufficient areal sweep and uniform spatial distribution of the injected steam. On the fifth year of simulation, the injection of steam as injecting fluid was scheduled to kick-off in order to enhance oil mobility and maintain reservoir pressure after two years of waterflooding. The model was run for a ten-year production period to evaluate the reservoir long term response and performance during steam injection.

#### 4.1.3.b Parameter Variation for Optimisation (Steam Injection)

A total of nine (9) runs were performed under different well constraints to optimise the injection rate and injection pressure of the injector wells for better recovery. A summary of the simulation runs and the parameters used is shown in the table below;

<b>Run No.</b>	<b>Injection Rate (bbl/day)</b>	<b>Injection Pressure (psi)</b>	<b>Oil Recovery Factor (%)</b>	<b>Water Cut (%)</b>	<b>Cumulative Oil Production (MSTB)</b>
1	2000	2000	46.33	65.65	1007.73
2	2000	2500	47.49	66.94	1032.96
3	2000	3000	48.64	68.00	1057.98
4	3000	2000	46.30	65.60	1007.07
5	3000	2500	47.68	67.12	1037.09
6	3000	3000	49.28	68.49	1071.90
7	4000	2000	46.27	65.56	1006.42
8	4000	2500	47.50	66.95	1033.18
9	4000	3000	49.35	68.53	1073.42

Table 4-4: Summary of Steam Injection Simulation Runs, Parameter Variations and Results.

The oil recovery, water cut, and cumulative oil production shown in the table above were calculated from the point where the oil started to decline sharply, but the wells were still producing a reasonable amount of oil. This period was chosen so that a more meaningful assessment of the reservoir performance under each injection scenario could be made.

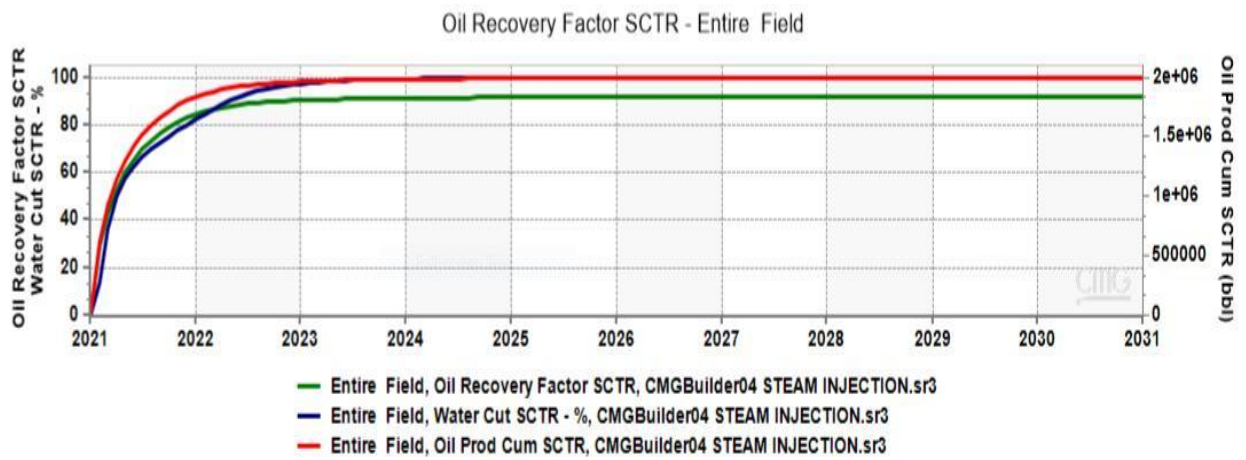
#### **4.1.3.c Simulation Results (Steam Injection)**

Simulation results from the steam injection scenarios were used to evaluate the impact of tuning injection rate and pressure in injector wells for oil recovery. The reservoir performance was observed to be highly influenced by variations in these parameters. In addition, in most cases higher injection pressures and higher injection rates enhanced the recovery factor by increasing heating effects and decreasing viscosity of oil.

The cumulative oil produced increased steadily with time, while the oil production rate declined gradually as the reservoir pressure decreased. W2000r cut increased towards the later stages of production, indicating more water breakthrough in the production wells. Overall, the simulation results show that the optimisation of the injection parameters had a positive impact on oil recovery.

The cumulative oil produced, water cut, and recovery factor for each of the different simulation runs are shown graphically in the figures below. The optimal injection rate and injection pressure combination that produced the best recovery performance was determined using these graphs.

**RUN 1:**



Injection Rate = 2000 bbl/day. Injection Pressure = 2000 psi.

*Figure 4-29: Combined Plot of Oil Recovery Factor, Water Cut, and Cumulative Oil Production with Time During the Steam Injection Process for Run 1.*

**RUN 2:**

Injection Rate = 2000 bbl/day.

Injection Pressure = 2500 psi.

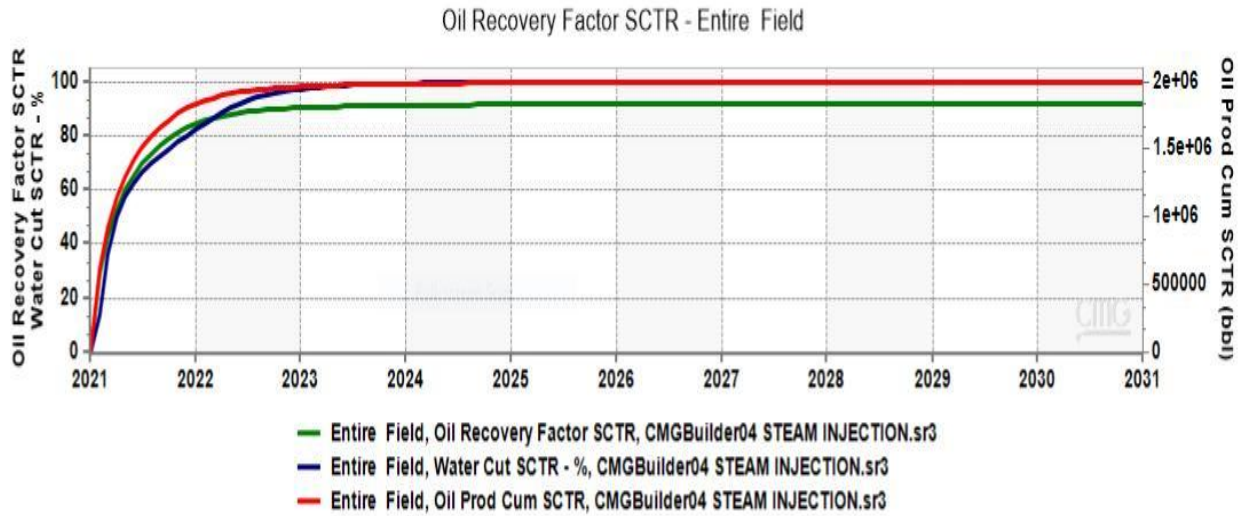


Figure 4-30: Combined Plot of Oil Recovery Factor, Water Cut, and Cumulative Oil Production with Time During the Steam Injection Process for Run 2.

### RUN 3:

Injection Rate = 2000 bbl/day.

Injection Pressure = 3000 psi.

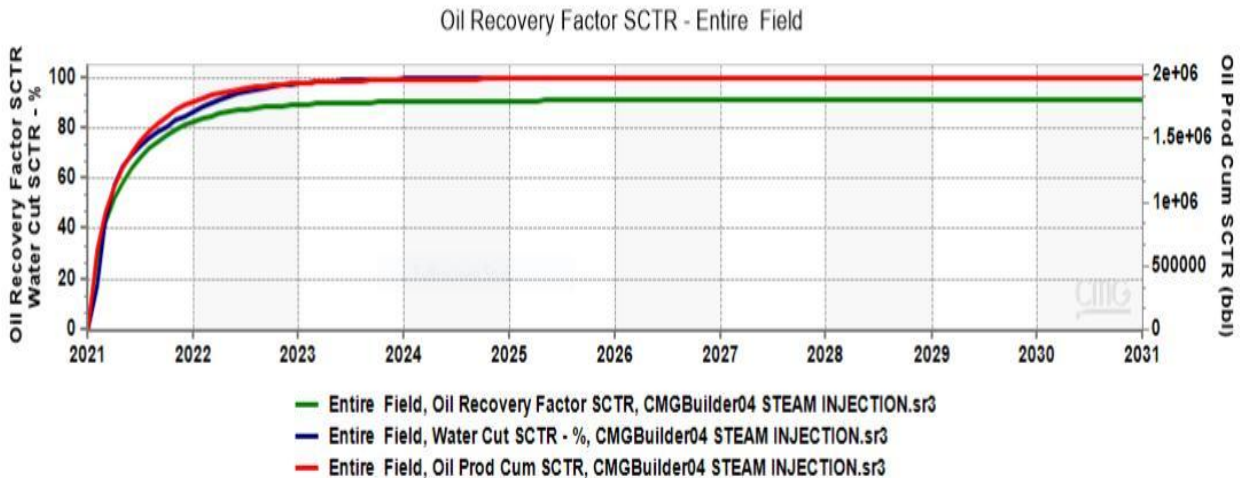
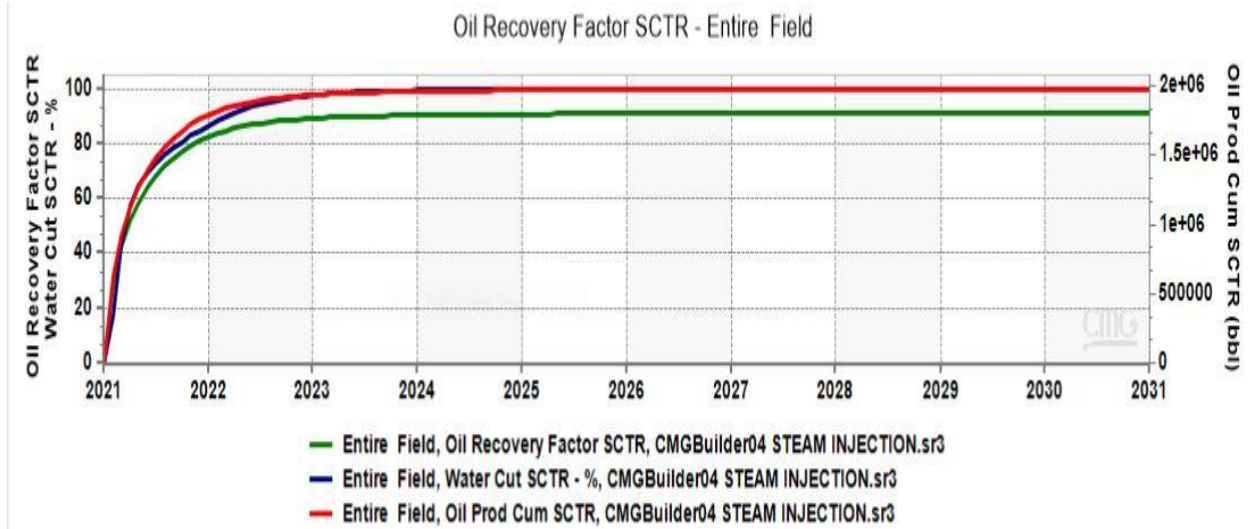


Figure 4-31: Combined Plot of Oil Recovery Factor, Water Cut, and Cumulative Oil Production with Time During the Steam Injection Process for Run 3.

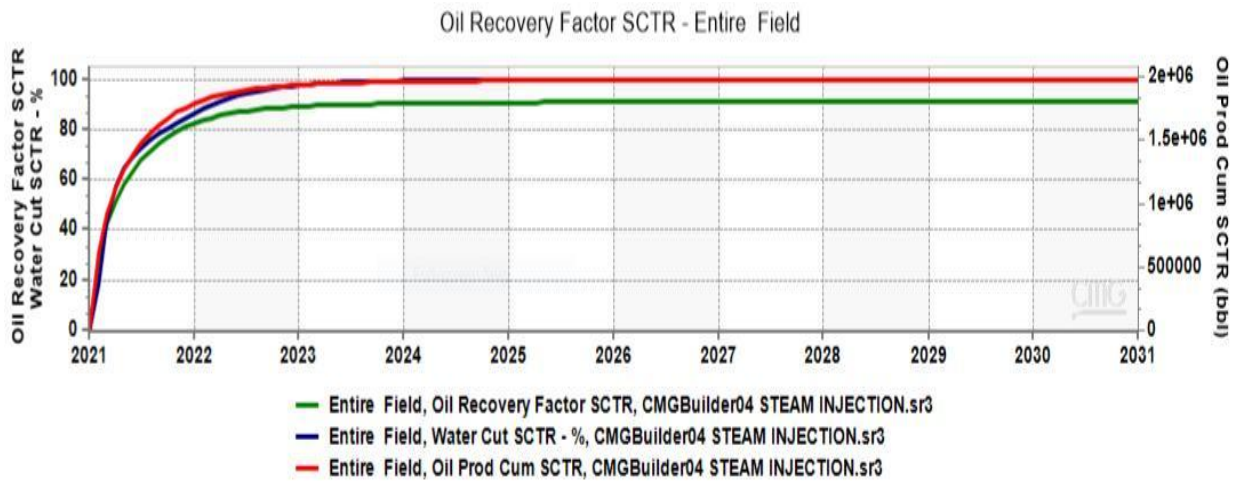
**RUN 4:**



Injection Rate = 3000 bbl/day.      Injection Pressure = 2000 psi.

Figure 4-32: Combined Plot of Oil Recovery Factor, Water Cut, and Cumulative Oil Production with Time During the Steam Injection Process for Run 4.

**RUN 5:**



Injection Rate = 3000 bbl/day.      Injection Pressure = 2500 psi.

Figure 4-33: Combined Plot of Oil Recovery Factor, Water Cut, and Cumulative Oil Production with Time During the Steam Injection Process for Run 5.

**RUN 6:**

Injection Rate = 3000 bbl/day.

Injection Pressure = 3000 psi.

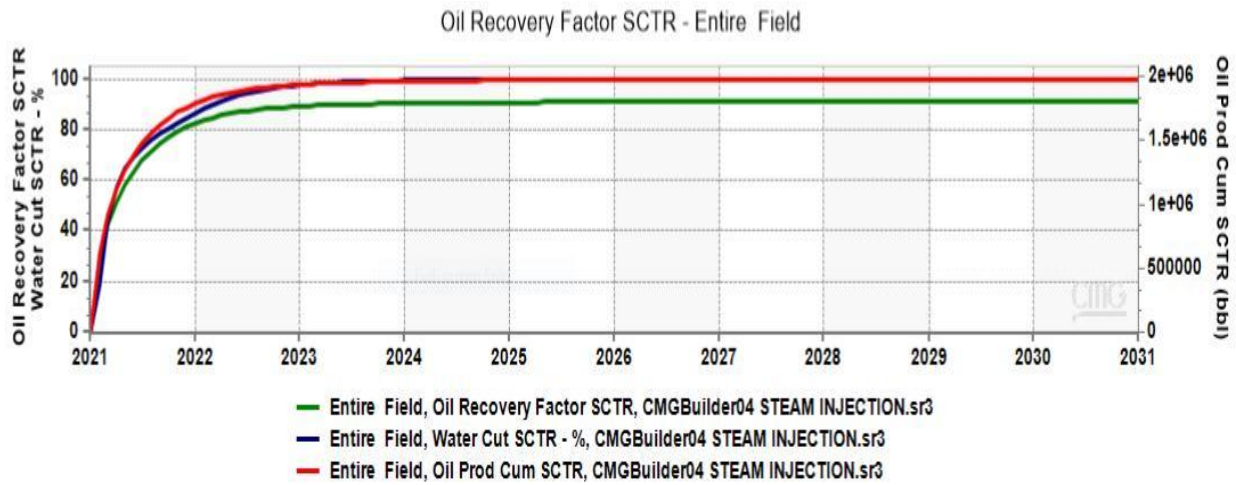


Figure 4-34: Combined Plot of Oil Recovery Factor, Water Cut, and Cumulative Oil Production with Time During the Steam Injection Process for Run 6.

**RUN 7:**

Injection Rate = 4000 bbl/day.

Injection Pressure = 4000 psi.

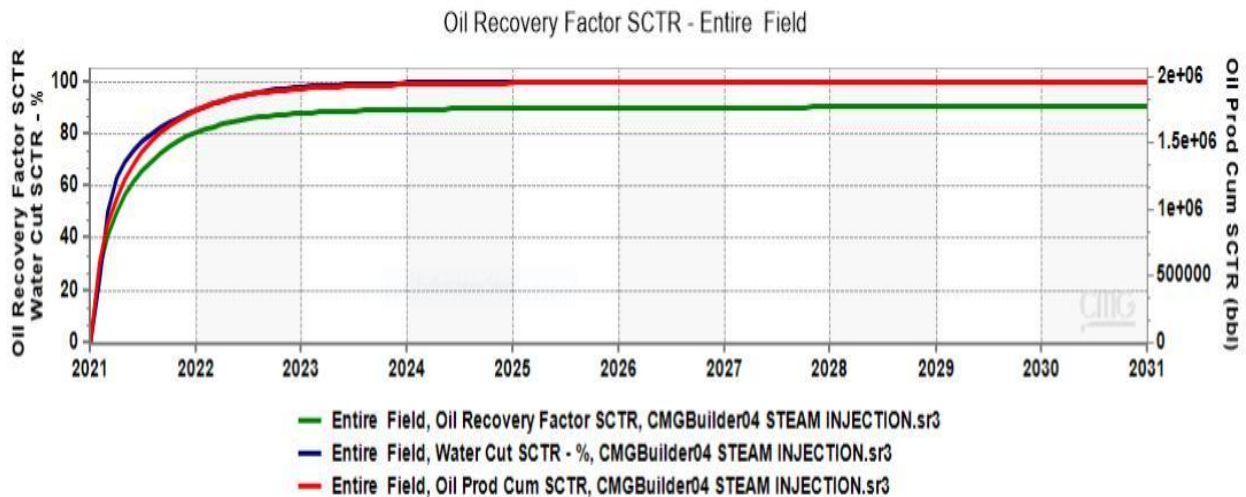
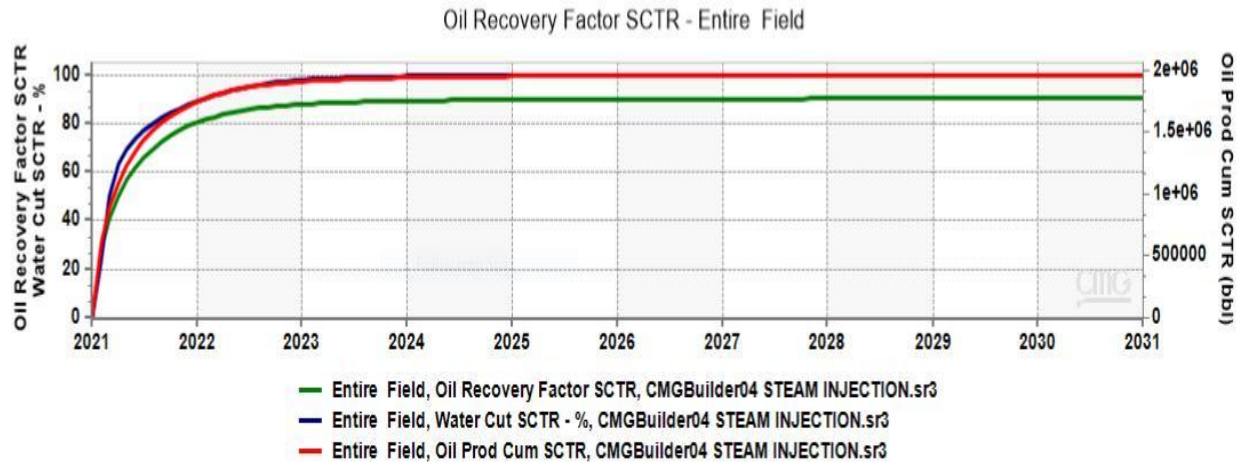


Figure 4-35 Combined Plot of Oil Recovery Factor, Water Cut, and Cumulative Oil Production with Time During the Steam Injection Process for Run 7.

**RUN 8:**



Injection Rate = 4000 bbl/day.                      Injection Pressure = 2500 psi.

Figure 4-36: Combined Plot of Oil Recovery Factor, Water Cut, and Cumulative Oil Production with Time During the Steam Injection Process for Run 8.

**RUN 9:**

Injection Rate = 4000 bbl/day.                      Injection Pressure = 3000 psi.

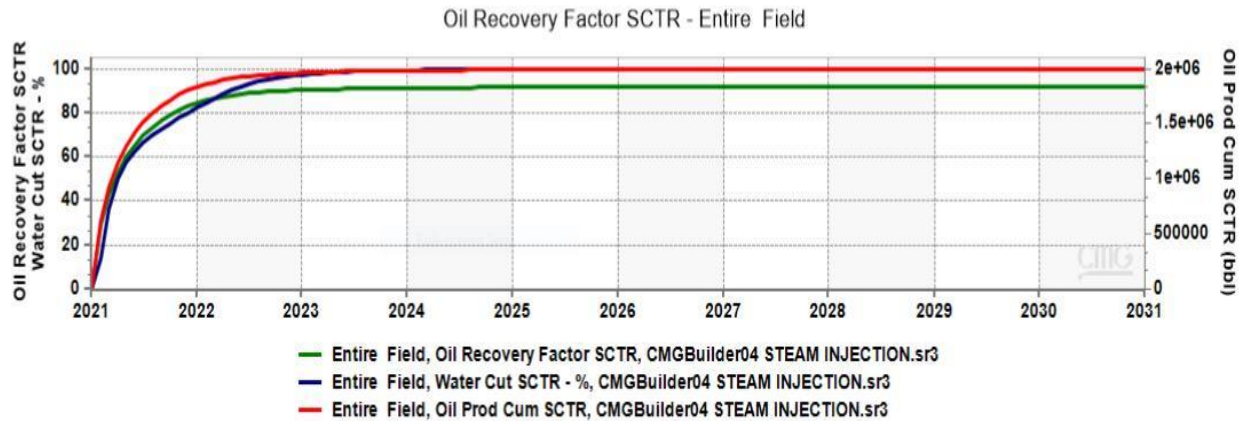


Figure 4-37: Combined Plot of Oil Recovery Factor, Water Cut, and Cumulative Oil Production with Time During the Steam Injection Process for Run 9.

#### 4.1.2.d Discussion and Analysis of Results (Steam Injection)

##### DISCUSSION OF RESULTS:

The results of the steam injection simulations clearly demonstrate how injection parameters influence the efficiency of oil recovery. The oil rate and cumulative oil production were also affected by variations in injection pressure and injection rate among the nine simulation runs. Overall, both the oil displacement efficiency and reservoir pressure maintenance improved with an increase in steam injection pressure and an increase in injection rate. This enhanced the thermal energy distribution within the reservoir, reduced oil viscosity, and consequently led to higher cumulative oil production and recovery factor.

However, it was also observed that at advanced stages of the simulation an excessive injection rate and pressure resulted in higher water production and water cut. This means that there can be an optimal tuning of the injection parameters to find a balance between the large costs of handling water cut and good oil recovery. The best run that resulted in maximum RF (Recovery

Factor) and cumulative oil production, from nine different runs, will be selected as the best set up of the injection parameters.

### **ANALYSIS OF RESULTS:**

When evaluating the “best” performance for Enhanced Oil Recovery (EOR) using steam injection, the following factors are considered:

1. Highest Oil Recovery Factor (RF) (%).
2. Highest Cumulative Oil Produced (MSTB).
3. Lowest Water Cut (%), Since high water cut means more water production and less oil production.

Now, from Table 4-4 in previous section (4.1.3.b)

The best run is;

**Run 3** - Injection Rate: 4000 bbl/day, Injection Pressure:3000 psi.

#### **Reasons:**

- It recorded the highest oil recovery factor (49.35%).
- It also achieved the highest cumulative oil production (1073.42 MSTB).
- Although its water cut (68.53%) is slightly higher, the gain in recovery and total oil production outweighs the water production.

## **CHAPTER 5**

### **CONCLUSION AND RECOMMENDATIONS**

## 5.1 Conclusion

Based on the findings from the simulation study, the following conclusions were drawn:

1. Injection rate and injection pressure: These are critical parameters that strongly influence reservoir recovery performance in all EOR processes.
2. Waterflooding: It serves as a baseline EOR method, and its performance improves at lower injection rates and higher pressures due to better sweep efficiency and pressure maintenance.
3. Polymer flooding achieved the highest oil recovery factor and cumulative oil production among all the methods studied. This was mainly due to the improved mobility ratio and reduced viscous fingering, which resulted in a more uniform displacement of oil and better sweep efficiency.
4. Steam injection also showed significant improvement in oil recovery compared to waterflooding, as the combined effects of heat and pressure reduced oil viscosity and enhanced flow within the reservoir.
5. Among the three techniques studied, polymer flooding proved to be the most effective EOR method under the simulated conditions of the black oil reservoir.

## 5.2 Recommendations

1. The present field-scale steam injection requires cautious optimisation of injection pressure and rate to ensure the successful distribution of heat and oil displacement.

2. Polymer flooding can be recommended to improve mobility control and displacement efficiency for the reservoirs for which the salinity is suitable and the temperature is moderate.
3. In any field, the EOR application leads to optimal performance only if the injection parameters are reasonably monitored and controlled. For example, since early breakthrough and fluids loss could considerably decrease, the recovery performance should guarantee that the process stays in the safe zone.
4. Economic evaluation should be conducted in future studies to determine the cost-effectiveness and feasibility of each EOR method at field scale.
5. Future work can also investigate hybrid EOR approaches (such as steam–polymer or surfactant–polymer combinations) and perform sensitivity analyses to further improve recovery efficiency under varying reservoir conditions.

### **5.3 Contribution to Knowledge**

This study contributes to knowledge by showing how optimisation of key injection parameters, mainly injection rate and injection pressure, affects oil recovery in a black oil reservoir using reservoir simulation with CMG (IMEX and STARS). Rather than applying a single injection condition, multiple simulation cases were analysed to identify the most suitable injection set-up for improved reservoir performance.

The results provide clearer insight into how changes in injection conditions influence recovery behaviour for different recovery methods.

**Case 1:** According to the study, lower injection rates and higher injection pressure improve sweep efficiency and pressure maintenance for water flooding. This explains the importance of achieving an appropriate balance between pressure and rate of injection for an efficient displacement during secondary recovery.

**Case 2:** The study proves that when polymer flooding is applied at a higher injection pressure and a lower injection rate, it produces the best performance compared to other methods. The findings of the study confirm that when polymer flooding is applied, it improves sweep efficiency by reducing fingering effects. The best scenario recorded in the study produced a cumulative oil production of **1137.37 MSTB** and an oil recovery factor of **52.29%**.

**Case 3:** The study also contributes to steam injection in that it proves that with higher injection pressures and rates, the distribution of heat in the reservoir is increased, which in turn reduces the viscosity and hence the mobility of the oil.

Overall, this study has advanced the understanding of black oil reservoirs in that it proves that with the optimisation of injection parameters, it is possible to increase oil recovery, enhance pressure support, and optimise reservoir performance. Moreover, this study has also come up with a useful workflow for reservoir studies similar in nature to this one.

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