PERFORMANCE EVALUATION OF POLYMER FLOODING AS AN EFFECTIVE ENHANCED OIL RECOVERY (EOR) TECHNIQUE IN NIGERIAN SANDSTONE RESERVOIRS

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BENIN CITY,

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A PROJECT SUBMITTED TO THE DEPARTMENT OF CHEMICAL ENGINEERING, UNIVERSITY OF BENIN, BENIN CITY, NIGERIA IN PARTIAL FULFILMENT OF THE REQUIREMENTS FOT THE AWARD OF BACHELOR OF ENGNEERING IN CHEMICAL

NOVEMBER, 2025

CERTIFICATION

This is to certify that this research project was carried out by **OGORO EZIELO** with matriculation number **ENG2002060** in the Department of Chemical Engineering, University of Benin, Benin City, Edo State Nigeria.

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DEDICATION

This work is dedicated firstly to Almighty God, My Mom for her unwavering support throughout the process of this work and equally to My Aunt and Brothers for their support throughout the period of this project.

ACKNOWLEDGEMENT

To God: Your divine and unwavering presence in my life has been my greatest source of strength and inspiration. I am deeply grateful for Your guidance and blessings throughout my undergraduate journey.

To my supervisor: Your nurturing and supportive nature provided me with the guidance I needed to navigate this project. Thank you, Sir, for your invaluable mentorship. I pray that your dedication and kindness will be richly rewarded.

To my family: Your unwavering love, encouragement, and support have been my foundation throughout this journey. I could not have done it without you, and for that, I am truly grateful.

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ABSTRACT

This research investigates the feasibility and performance of polymer flooding as an enhanced oil recovery (EOR) method for Nigerian sandstone reservoirs. With the growing need to improve oil recovery from mature fields and reduce dependency on primary and secondary recovery techniques, polymer flooding has emerged as a promising tertiary recovery strategy. The study focuses on evaluating the technical and operational effectiveness of injecting hydrolyzed polyacrylamide (HPAM) polymer solution under representative Nigerian reservoir conditions using the CMG-STARS simulation software.

A detailed reservoir model was developed, incorporating a six-layer sandstone formation characterized by an average porosity of 20%, initial pressure of 2299.2 psi, and oil viscosity of 5 cP. Two simulation cases were analyzed: a base case (without EOR) and a polymer flooding case with a 2000 ppm polymer solution injected over a 30-year production period (2025–2055). The performance of both scenarios was evaluated based on field oil production rate, bottom-hole pressure, water cut, and cumulative oil recovery.

The results revealed that polymer flooding significantly improved reservoir performance compared to the base case. While the base case exhibited a steady decline in pressure and oil rate leading to early depletion around 2047, the polymer injection maintained an average pressure of about 2100 psi throughout the simulation. The polymer case also achieved a cumulative oil recovery of 23.6 million stock tank barrels (MMSTB), representing an incremental gain of 5.8 MMSTB (32.6%) over the base case. Furthermore, water cut was reduced from 89% to 68%, indicating better mobility control and sweep efficiency. These findings confirm that polymer flooding is a technically viable and cost-effective EOR method for Nigerian sandstone reservoirs, capable of improving oil displacement efficiency and extending field life. The study recommends that field pilot projects be implemented to validate simulation outcomes and optimize polymer formulation for local reservoir conditions. Overall, this research demonstrates that polymer flooding can play a vital role in maximizing Nigeria’s oil recovery potential, supporting energy sustainability, and promoting efficient reservoir management.

CHAPTER ONE

INTRODUCTION

1.1 BACKGROUND OF THE STUDY

Crude oil has remained the backbone of global energy and economic growth for more than a century, serving as the principal source of fuel, industrial feedstock, and foreign exchange for many countries. In Nigeria, petroleum exploitation and export have underpinned national revenue, industrial development, and infrastructure investment. The Niger Delta region in particular hosts a large number of sedimentary basins that have produced substantial quantities of hydrocarbons since the mid- 20th century (Adeoti et al., 2019). Despite strong historical output, many of these reservoirs are now classed as mature, with declining natural drive and reduced well productivity.

The recovery of oil from subsurface reservoirs is governed by the interplay of reservoir rock properties, fluid properties and characteristics, and the drive mechanisms available. There are three main classifications of oil recovery techniques in general which are primary, secondary and tertiary recovery methods which is also known as Enhanced oil recovery (EOR) (Green & Willhite, 1998). Primary recovery relies on the use of the natural reservoir energy (solution gas drive, water drive, gas cap expansion drive, gravity drainage drive and rock compaction), while secondary recovery typically involves water- flooding to maintain pressure and sweep oil toward production wells. Combined, these strategies commonly recover between 20% and 40% of the original oil in place (OOIP) for sandstone reservoirs figures that vary strongly with rock anisotropy and heterogeneity, fluid viscosity, and operational design (Lake, 1989).

Enhanced Oil Recovery (EOR) techniques aim to mobilize the larger fraction of OOIP left behind after primary and secondary recovery. EOR methods can be thermal flooding which is the use of heat to reduce the viscosity of crude in the reservoir increasing its mobility, gas-based flooding (miscible or immiscible) which involves the injection of gas into a reservoir to increase the overall pressure, chemical flooding which is the injection of chemical substances like polymers, surfactants and alkaline chemicals to alter the rock-fluid properties, and biological (microbial) flooding which involves using micro-organisms and their metabolic by-products to improve oil displacement. Among chemical EOR methods, polymer flooding has emerged as a practical solution for sandstone reservoirs where temperature is moderate and oil viscosity is not extremely high (Hadi, 2023). Polymer flooding is the use of water-soluble polymers to increases the viscosity of the injected aqueous phase (water), causing a piston-like displacement of oil improving the mobility ratio between displacing fluid (polymer solution) and displaced fluid (oil). A favorable mobility ratio (<1) reduces viscous fingering and improves volumetric sweep efficiency which is critical in heterogeneous reservoirs such as many Nigerian sandstones (Gbadamosi et al., 2022).

Polymer flooding has a track record in several petroleum provinces worldwide. Large-scale implementations in China, Canada, and parts of South America demonstrate incremental oil recoveries ranging from a few percent to more than ten percent of OOIP over the life of the projects, depending on rock quality and polymer management (Scott et al., 2020). Technological advances in polymer chemistry including brine-tolerant polymers, shear-resistant formulations, and improved understanding of adsorption and retention mechanisms have increased the operational feasibility of polymer EOR in challenging environments (Gbadamosi et al., 2022).

Nigerian sandstone reservoirs present a mixed picture for polymer implementation. Many formations have moderate permeability (often in the tens to hundreds of millidarcies) and significant heterogeneity caused by facies changes, faults, and layered depositional sequences.

Reservoir salinity can vary widely and formation temperatures can be elevated in deeper sections. Clay content and the presence of fines can lead to polymer adsorption and pore plugging if not properly managed (Hadi, 2023). On the other hand, the existing water-flood infrastructure in many fields, combined with the need to economically extract stranded oil, makes polymer flooding an attractive candidate for pilot and field-scale testing (EOR Alliance, 2025).

This research situates polymer flooding in the specific geological, operational, and regulatory context of Nigeria. It provides a simulation-driven feasibility analysis using reservoir models that reflect typical Nigerian sandstone characteristics and operational constraints. The analysis integrates reservoir engineering principles, polymer rheology, and operational risk factors to provide a robust assessment of polymer EOR potential in the country.

1.2 PROBLEM STATEMENT

Despite decades of production, many Nigerian oil fields are experiencing declining production rates as conventional recovery methods (primary and secondary) reach their practical limits. Primary recovery mechanisms capture an initial fraction of OOIP, and secondary water-flooding though cost-effective often fails to access substantial portions of the reservoir due to poor sweep efficiency. This under-recovery represents both a lost national resource and an economic opportunity cost particularly as fields transition from high-rate production to marginal economics (Sheng, 2011).

Water-flood inefficiency in sandstone reservoirs is commonly manifested by early water breakthrough, channeled flow through high-permeability streaks which is known as viscous fingering, and bypassed oil in low-permeability or poorly connected zones. These phenomena are exacerbated in reservoirs with high permeability contrasts, complex layering, and significant natural fractures. In the context of Nigerian sandstones, additional complicating factors include variable formation water salinity which can cause polymer precipitation, elevated temperatures at depth, and the presence of clays that may interact adversely with injected polymers (Hadi, 2023). Although polymer flooding promises improved sweep and incremental oil recovery, several uncertainties have hindered broad adoption in Nigeria:

- compatibility of common commercial polymers with high-salinity formation waters and reservoir brines;
- polymer retention by adsorption and mechanical entrapment, which reduces effective polymer concentration in the flood front (Scott et al., 2020);
- shear degradation due to high injection rates or near-wellbore flow restrictions; operational challenges related to polymer mixing, injection facilities, and produced water handling;
- economics under local cost structures and oil price volatility (Gbadamosi et al., 2022).

  Consequently, there is a pressing need for a focused feasibility study that quantifies expected recovery gains, identifies the dominant technical risks, and explores operational design choices for polymer injection in Nigerian sandstone reservoirs. This study addresses that need by using reservoir simulation to predict performance across a range of plausible reservoir and polymer scenarios, thereby offering actionable insight for field engineers and decision-makers.

1.3 AIM AND OBJECTIVES OF THE STUDY

The primary aim of this research is to evaluate the technical and economic feasibility of polymer flooding as an enhanced oil recovery technique for Nigerian sandstone reservoirs.

To accomplish this aim, the study pursues the following specific objectives:

1. Conduct a comprehensive review of polymer flooding fundamentals, including polymer rheology, adsorption, retention, and degradation mechanisms (Hadi, 2023).
2. Characterize key reservoir and fluid properties relevant to polymer flooding performance in typical Nigerian sandstone formations, including permeability distribution, porosity, initial saturations, temperature, and formation brine composition.
3. Build a representative Eight-layer reservoir model in CMG STARS that captures heterogeneity and flow dynamics characteristic of Niger Delta sandstones.
4. Simulate a matrix of polymer injection scenarios to evaluate the effect of polymer injection relative to conventional water-flooding, and injection strategy on incremental oil recovery and water-cut.
5. Quantify polymer retention, expected polymer consumption, and sensitivity to adsorption and mechanical losses (Scott et al., 2020).
6. Perform a preliminary economic assessment to estimate incremental revenue versus polymer and operational costs, identifying scenarios with favorable net present value under reasonable price assumptions.
7. Provide technical recommendations and risk mitigation strategies for pilot testing and potential field deployment.

These objectives provide a structured pathway from theoretical understanding through simulation and evaluation to practical recommendations for field implementation.

1.4 SCOPE OF THE STUDY

This thesis is a simulation-based feasibility study of polymer flooding targeted at sandstone reservoirs typical of the Nigerian Niger Delta basin. The study uses a combination of published field data, representative petro-physical parameters, and synthetic inputs tailored to reflect Nigerian reservoir conditions. The analysis focuses on:

1. Building a layered reservoir model that captures vertical and lateral heterogeneity common to Niger Delta sandstones.
2. Incorporating polymer-specific parameters including viscosity versus concentration relationships, adsorption isotherms, shear sensitivity, and thermal stability constraints (Scott et al., 2020).
3. Simulating multiple operational strategies: polymer slug injection, continuous low-concentration injection (WAG-like), and combinations with ongoing water-floods.

The study does not involve laboratory experiments for polymer synthesis, detailed polymer–brine–rock compatibility testing in the laboratory or actual field pilot implementation due to its exorbitant cost, this project is a very capital intensive one. Environmental impact considerations are discussed qualitatively, but comprehensive environmental or regulatory permitting analyses are out of scope. Similarly, while a preliminary economic evaluation is included, a full project-level financial model with detailed CAPEX and OPEX breakdowns and field-specific contractor quotations is not within this work.

The scope is intentionally calibrated to provide decision-useful technical insight while remaining feasible within the constraints of a final-year research project.

1.5 SIGNIFICANCE OF THE STUDY

The significance of this research is multifold. Firstly, it provides a regionally focused technical evaluation of polymer EOR that complements global literature with insights relevant to Nigerian reservoir conditions. For reservoir engineers, field operators, and policymakers, the findings aim to reduce uncertainty around polymer EOR performance and economics in local contexts.

Key contributions include:

1. Technical quantification of potential incremental recovery: Simulation results will help estimate the additional percentage of OOIP recoverable through polymer injection under typical reservoir scenarios.
2. Identification of risk drivers: The study highlights which parameters (e.g., adsorption, heterogeneity, salinity) most strongly influence outcomes, guiding laboratory and pilot testing priorities (Hadi, 2023).
3. Operational guidance: By modelling injection strategies, the study informs decisions about injection rates, slug sizes, monitoring needs, and produced water handling.
4. Economic signals: Preliminary economic analysis indicates whether polymer projects could be viable under current cost and price regimes, identifying thresholds for investment.

More broadly, successful demonstration of polymer EOR feasibility could translate into prolonged field life, improved national hydrocarbon recovery, and better returns on existing infrastructure investments. The research also serves as a pedagogical contribution to academic literature at the University of Benin and supports capacity building for local engineers and students interested in EOR techniques.

1.6 METHODOLOGICAL APPROACH

This study adopts a mixed methodological approach combining literature review, data synthesis, and numerical reservoir simulation using CMG STARS. The methodology is organized in discrete phases:

1. Literature and data acquisition: Review polymer EOR fundamentals, field case studies, and polymer- brine- rock interaction studies. Collect representative reservoir parameters

(porosity, permeability ranges, OOIP estimates, fluid PVT properties, and formation water salinity) from Nigerian field reports and published literature (Scott et al., 2020).

2. Model design and initialization: Construct a Eight-layer reservoir model that encapsulates vertical heterogeneity, net-pay distribution, and key petro-physical ranges. Initialize the model with representative initial conditions such as reservoir pressure, temperature, initial water saturation (Swi), and gas-oil ratios where applicable.
3. Polymer property integration: Define polymer rheological models (viscosity as a function of shear rate and concentration), adsorption isotherms, retention coefficients, and degradation factors. Calibrate these using literature values for common polymers (e.g., partially hydrolyzed polyacrylamide—HPAM) and available field data (Gbadamosi et al., 2022).
4. Scenario simulation: Run a suite of simulation cases to test sensitivity to polymer concentration, slug size, injection timing, injection well placement, and heterogeneity. Scenarios include baseline production without injection for comparison and multiple polymer strategies.
5. Analysis and economic screening: Analyze production metrics (cumulative oil, incremental oil, water-cut trends), polymer consumption, and projected life-of-field performance. Conduct a preliminary economic screening to compare incremental revenue against polymer and operational costs using simplified cash-flow calculations.
6. Validation and uncertainty assessment: Perform sensitivity analyses and, where possible, compare simulated performance trends with published field cases to assess plausibility (Scott et al., 2020).

The CMG STARS simulator is chosen for its robust handling of polymer EOR physics, including complex rheology and adsorption models, which are essential for realistic forecasts.

1.7 ORGANIZATION OF THE REPORT

The thesis is organized into five principal chapters designed to guide the reader from background knowledge through to practical conclusions and recommendations:

1. Chapter One: Introduction; provides context, problem statement, objectives, scope, and methodological overview.
2. Chapter Two: Literature Review; surveys polymer EOR mechanisms, polymer chemistries, field applications, and laboratory- to- field scaling challenges (Manrique et al., 2022).
3. Chapter Three: Materials and Methods — details the reservoir model, data inputs, polymer property selection, and simulation setup in CMG STARS.
4. Chapter Four: Results and Discussion — presents simulation outcomes, sensitivity analyses, polymer consumption estimates, and an economic screening of scenarios.
5. Chapter Five: Conclusions and Recommendations — summarizes key findings, presents recommendations for pilot design and further research, and discusses limitations.

Appendices provide supplementary tables, detailed input decks, sensitivity cases, and code snippets used to generate the simulation runs.

1.8 JUSTIFICATION OF THE STUDY

Nigeria's oil sector is at a crossroads where maximizing recovery from existing fields is necessary to sustain production and maintain government revenues. Given the capital- intensive nature of new exploration and development, EOR technologies such as polymer flooding offer a way to economically extract additional volumes from mature fields (Alvarado & Manrique, 2010).

Justification points include:

1. Resource optimization: Polymer EOR can access residual oil left behind by water- floods, increasing national recoverable reserves.
2. Cost- effectiveness: Relative to thermal or CO_2 EOR, polymer flooding often requires lower capital expenditure and can be retrofitted to existing injection infrastructure (EOR Alliance, 2025).
3. Environmental benefits: By improving sweep and reducing produced water volumes, polymer floods can lower surface disposal requirements and associated environmental impacts.
4. Strategic value: Demonstrating polymer EOR success in Nigeria would build local expertise, reduce dependence on foreign technical solutions, and support enterprise and job creation in downstream services.

By combining simulation, literature evidence, and economic screening, this research aims to provide a balanced technical and practical justification for considering polymer EOR pilots in Nigerian sandstone reservoirs.

1.9 SUMMARY

This chapter has laid out the rationale, objectives, scope, and methodological framework for examining polymer flooding feasibility in Nigerian sandstone reservoirs. It emphasized both the technical potential and the practical challenges inherent in applying polymer EOR under local reservoir conditions.

The following chapter will examine prior studies, polymer chemistries, adsorption and retention processes, field implementations, and lessons learned that inform the simulation parameters and operational recommendations.

CHAPTER TWO

LITERATURE REVIEW

2.1 INTRODUCTION TO LITERATURE REVIEW

This chapter presents a comprehensive literature review that synthesizes foundational theory and recent research on polymer flooding as a method of enhanced oil recovery (EOR), with emphasis on applicability to Nigerian sandstone reservoirs.

The review aims to

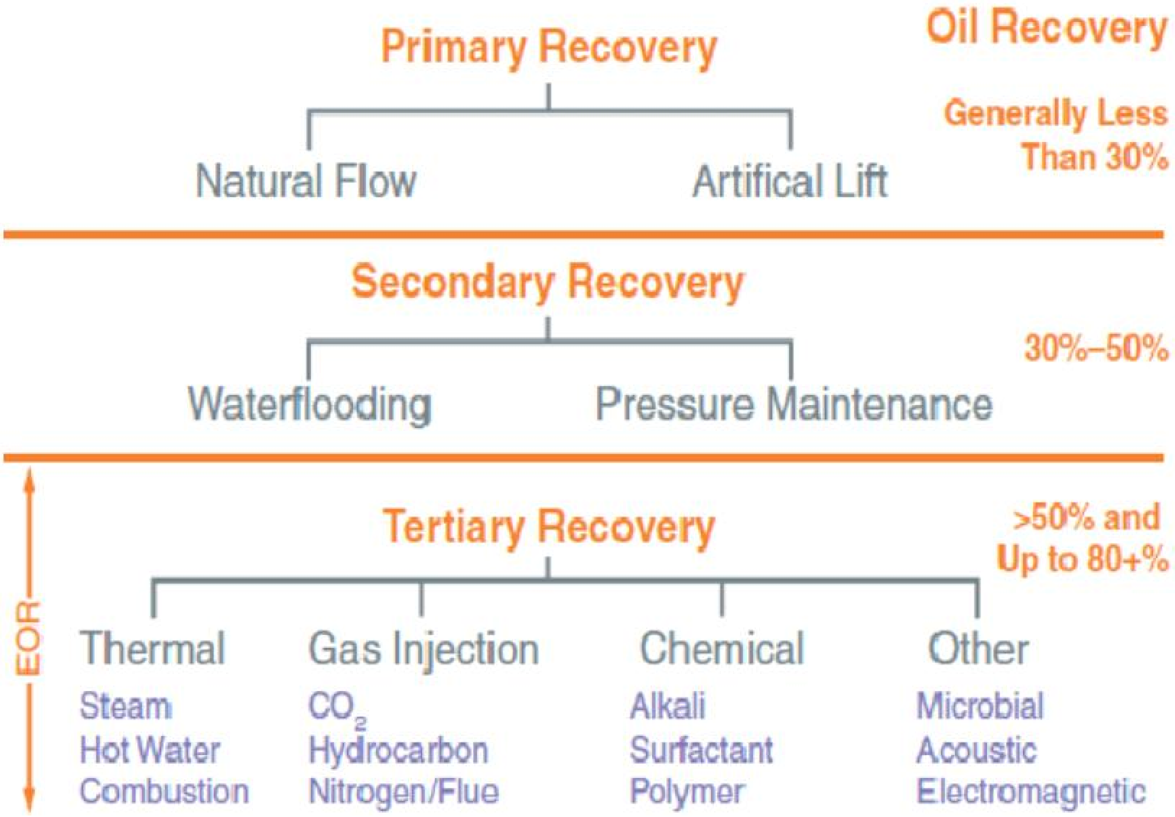
1. establish the theoretical and practical bases of polymer flooding;
2. evaluate laboratory and field-scale evidence on polymer performance under varying reservoir conditions;
3. identify the physicochemical interactions between polymers, reservoir fluids, and rock; and
4. expose research gaps that justify the present study's focus on feasibility in Nigerian contexts.

The structure of this literature review follows a thematic approach. It begins with a short overview of EOR concepts and classification, then narrows to chemical EOR and the rationale for polymer flooding. Subsequent sections explore the mechanisms of polymer action, types of polymers commonly used in field projects (e.g., partially hydrolyzed polyacrylamide, HPAM; xanthan and other biopolymers), rheological behavior, and degradation pathways under high temperature high salinity (HTHS) environments. The review continues by examining rock-fluid-polymer interactions such as adsorption, retention, pore plugging, and wettability changes, and how these processes affect injectivity and sweep efficiency. Field and pilot case studies from major projects notably Daqing (China) and several North American and European pilots are summarized to highlight practical lessons, design strategies, and observed incremental oil recovery (IOR) metrics. Finally, the chapter discusses economic and environmental considerations, and identifies key knowledge gaps with specific attention to the Niger Delta and other Nigerian sandstone reservoirs.

Polymer flooding has evolved from laboratory curiosity to one of the most widely applied chemical EOR methods. Recent reviews and syntheses demonstrate a renewed interest in polymer-based mobility control owing to its cost-effectiveness compared to surfactant or alkaline methods for many reservoirs, and to operational advances that allow application in increasingly challenging conditions. Comprehensive reviews in the last decade emphasize why HPAM remains the dominant choice chiefly for its cost, availability, and proven field performance while noting the growing interest in alternative or modified polymers for better thermal and salinity stability. The factors that determine a polymer project's success include polymer selection and formulation, injection strategy (slug, continuous, tapered, or PAW polymer-alternating-water), pre-treatment steps such as profile modification, and careful matching to reservoir temperature, salinity, and rock mineralogy. Field syntheses report incremental oil recovery ranging widely depending on reservoir heterogeneity and design, but several large projects have reported IOR improvements on the order of single-digit to low-teens percent of OOIP when compared to pre-polymer water-flood baselines. These performance ranges and design lessons are summarized and discussed in the sections that follow.

2.2 OVERVIEW OF OIL RECOVERY

Oil recovery is a critical aspect of the oil and gas industry, as it enables the extraction of hydrocarbon resources from underground reservoirs. With the increasing global demand for energy, optimizing oil recovery is essential to maximize the production of existing fields, extend their lifespan, and ultimately meet the world's energy needs. Oil recovery refers to the collective methods employed to extract crude oil from subsurface reservoirs. It typically occurs in three major stages: primary, secondary, and tertiary (enhanced) recovery. Each stage represents a different approach to maximizing hydrocarbon extraction efficiency by utilizing the natural and artificial energy mechanisms of the reservoir (OilGasZ, 2025). This section provides an overview of these stages, their underlying principles, common techniques, and expected recovery efficiencies.



(Abubaker 2015)

Figure 2.1: Different stages of oil recovery

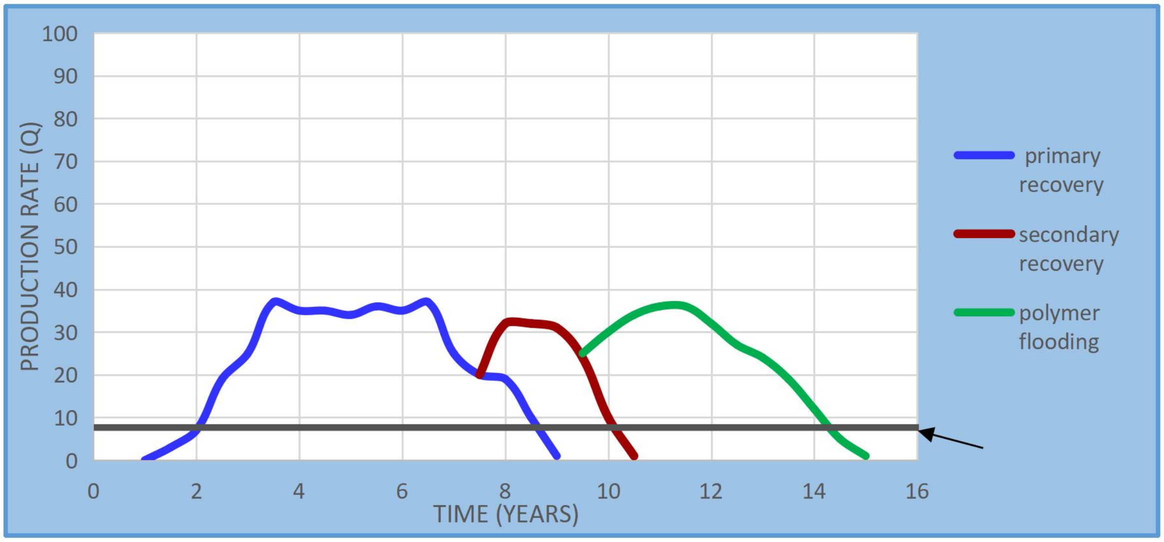


Figure 2.2: Estimated recovery factors for different stages of oil recovery

2.2.1 PRIMARY OIL RECOVERY METHODS

Primary oil recovery is the initial phase of hydrocarbon production and relies solely on the natural energy of the reservoir to drive oil to the surface. This natural energy is derived from mechanisms such as solution gas drive, gas cap expansion, water drive, and gravity drainage (Lake, 2014).

Common mechanisms include:

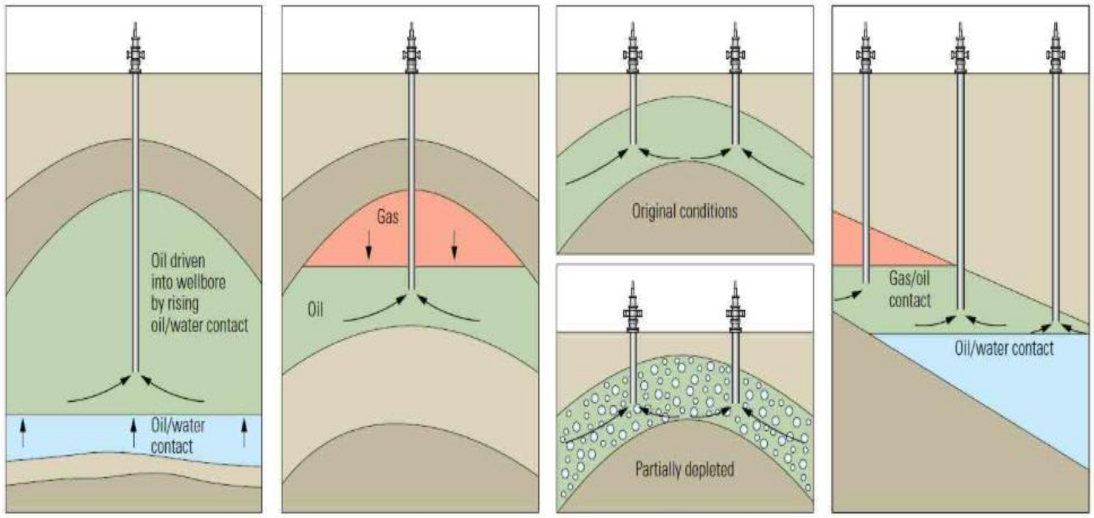
1. Solution Gas Drive - Expansion of dissolved gas in the oil phase.
2. Gas Cap Drive – Expansion of a free gas cap above the oil zone.
3. Water Drive – Natural water influx from an underlying aquifer.
4. Gravity Drainage – Oil movement due to density differences.
   In a solution gas drive system, oil initially contains dissolved gas under reservoir pressure. As pressure decreases due to production, the gas comes out of solution and expands, providing energy to push the oil toward production wells.

Gas cap drive operates similarly but uses an existing gas cap in the reservoir to maintain pressure and displace oil.

Water drive mechanisms involve an active aquifer pushing oil toward producing wells, maintaining a more stable production rate.

And gravity drainage refers to a mechanism or process where fluid (such as water, oil or gas) moves through the reservoir due to the force of gravity, in this context, gravity acts as the primary driving force causing the fluid to flow downwards or from areas of higher potential energy to areas of lower potential energy

The efficiency of primary recovery depends on the type of drive mechanism, reservoir permeability, and fluid properties. Recovery factors typically range from 5% to 20% of the original oil in place (OOIP). Artificial lift methods such as sucker rod pumps, electrical submersible pumps, or gas lift are often used to sustain production as reservoir pressure declines (Green & Willhite, 2018).



(SLB 2025)

Figure 2.3: Formation drive mechanisms. Water drive systems (left) rely on water from a connected aquifer to replace produced oil. Gas cap drives (middle left) are energized by

expanding gas that fills the voids that occur after liquids are removed. Gas in the saturated oil of a solution-gas drive system (middle right) comes out of solution after the reservoir pressure drops below the bubble point. Gravity, or combination drive systems (right), have gas, oil and water layers. As the oil is produced, the gas/oil contact drops as the gas cap expands, and the oil/water contact rises.

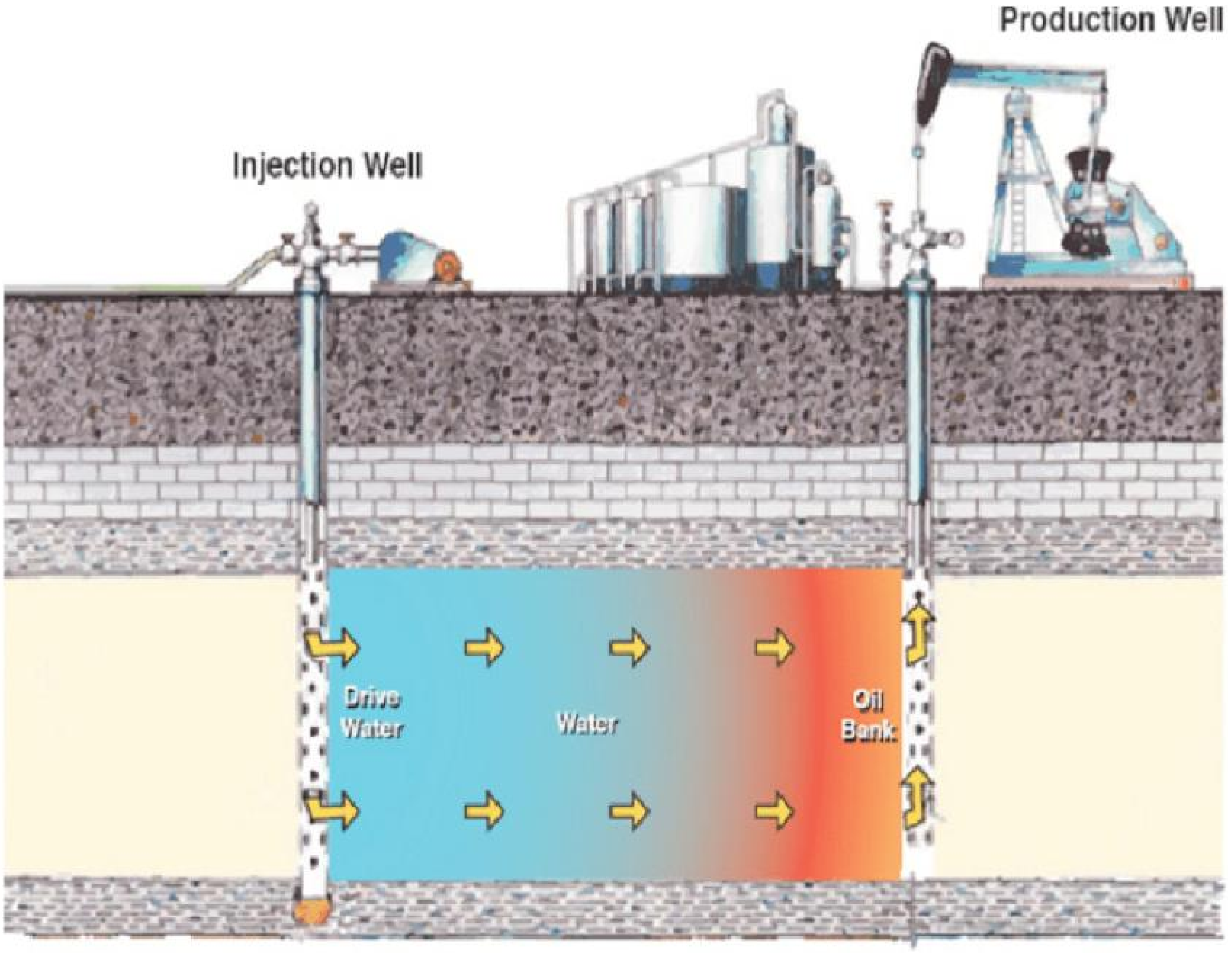
2.2.2 SECONDARY OIL RECOVERY METHODS

Once the natural energy of the reservoir is depleted, secondary recovery methods are introduced to maintain reservoir pressure and improve oil displacement. This stage primarily involves the injection of fluids such as water or gas to sweep additional oil toward production wells. Secondary recovery can increase total recovery to around 30–50% of OOIP (OilGasZ, 2025).

Typical methods include:

1. Water-flooding – Injection of water to displace oil toward producing wells.
2. Gas Injection – Use of gas (e.g., natural gas, CO_2) to maintain pressure.

Water-flooding involves injecting water into the reservoir through strategically placed injection wells to displace oil toward producing wells. This method restores pressure and improves the sweep efficiency, thereby recovering additional oil beyond the primary stage. The effectiveness of water-flooding depends on factors such as reservoir heterogeneity, viscosity ratio between water and oil, and injection rate (Alvarado & Manrique, 2010). Gas injection, on the other hand, involves injecting gases such as natural gas, nitrogen, or carbon dioxide to maintain reservoir pressure and improve oil recovery. CO_2 flooding, for example, can dissolve in oil and reduce its viscosity, improving flow characteristics. Secondary recovery can increase recovery factors to about 30–50% of OOIP (Green & Willhite, 2018).



(Vitalij 2017)

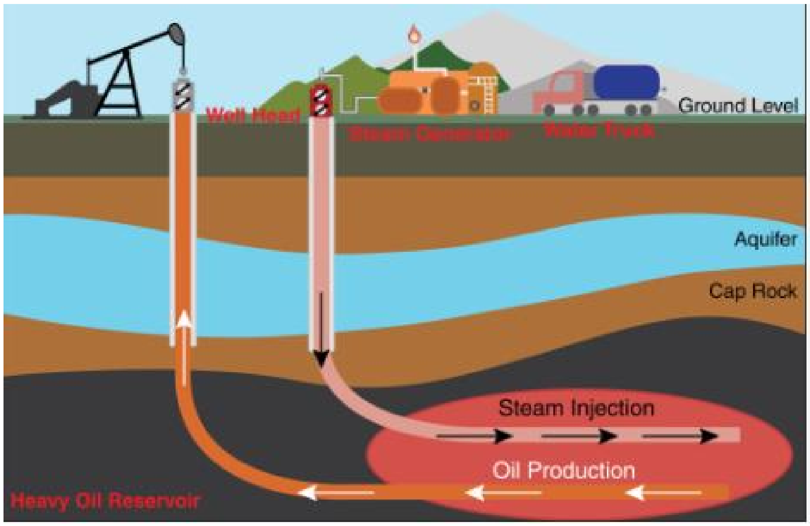
Figure 2.4: Diagram illustrating water-flooding method of secondary recovery

2.2.3 TERTIARY (ENHANCED) OIL RECOVERY METHODS

Tertiary or enhanced oil recovery (EOR) involves advanced methods to alter the physical or chemical properties of the reservoir fluids and rocks to extract residual oil. These methods aim to recover an additional 10–20% of OOIP beyond secondary recovery (AAPG Wiki, 2023). EOR techniques include thermal, chemical, and gas-based processes.

Main categories include:

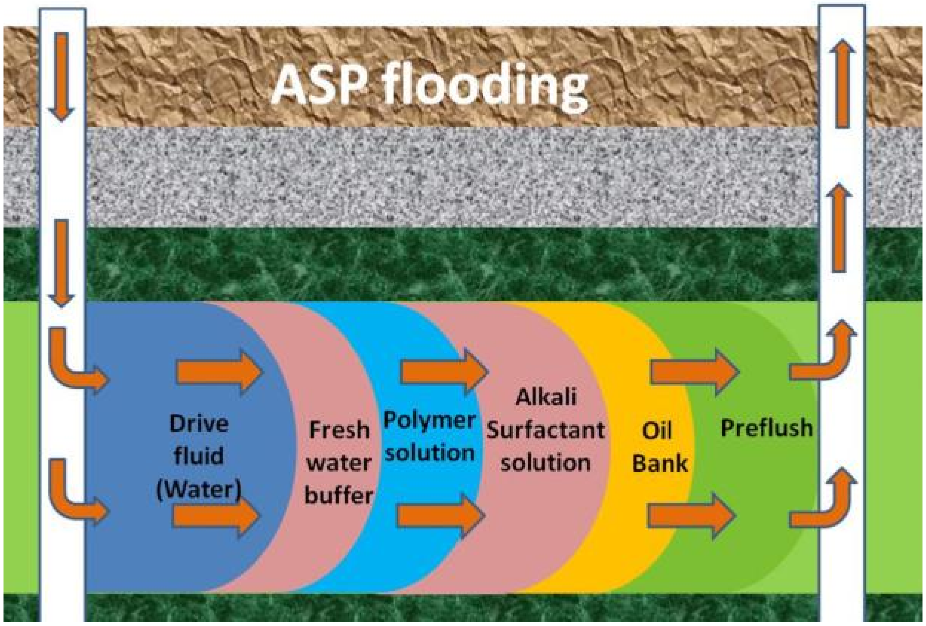
- Thermal Recovery - Steam flooding or in-situ combustion to reduce oil viscosity.



(Dheiaa 2020)

Figure 2.5 :

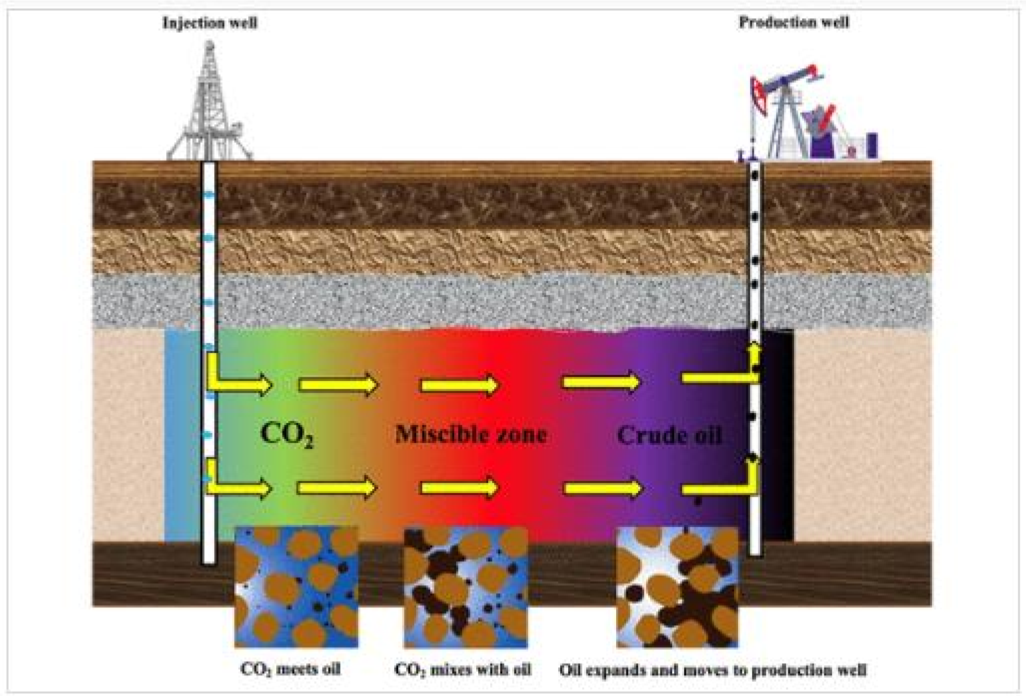
- Chemical Flooding - Injection of surfactants, polymers, or alkaline agents to improve mobility ratio.



(Swift Technical Solutions 2016)

Figure 2.6

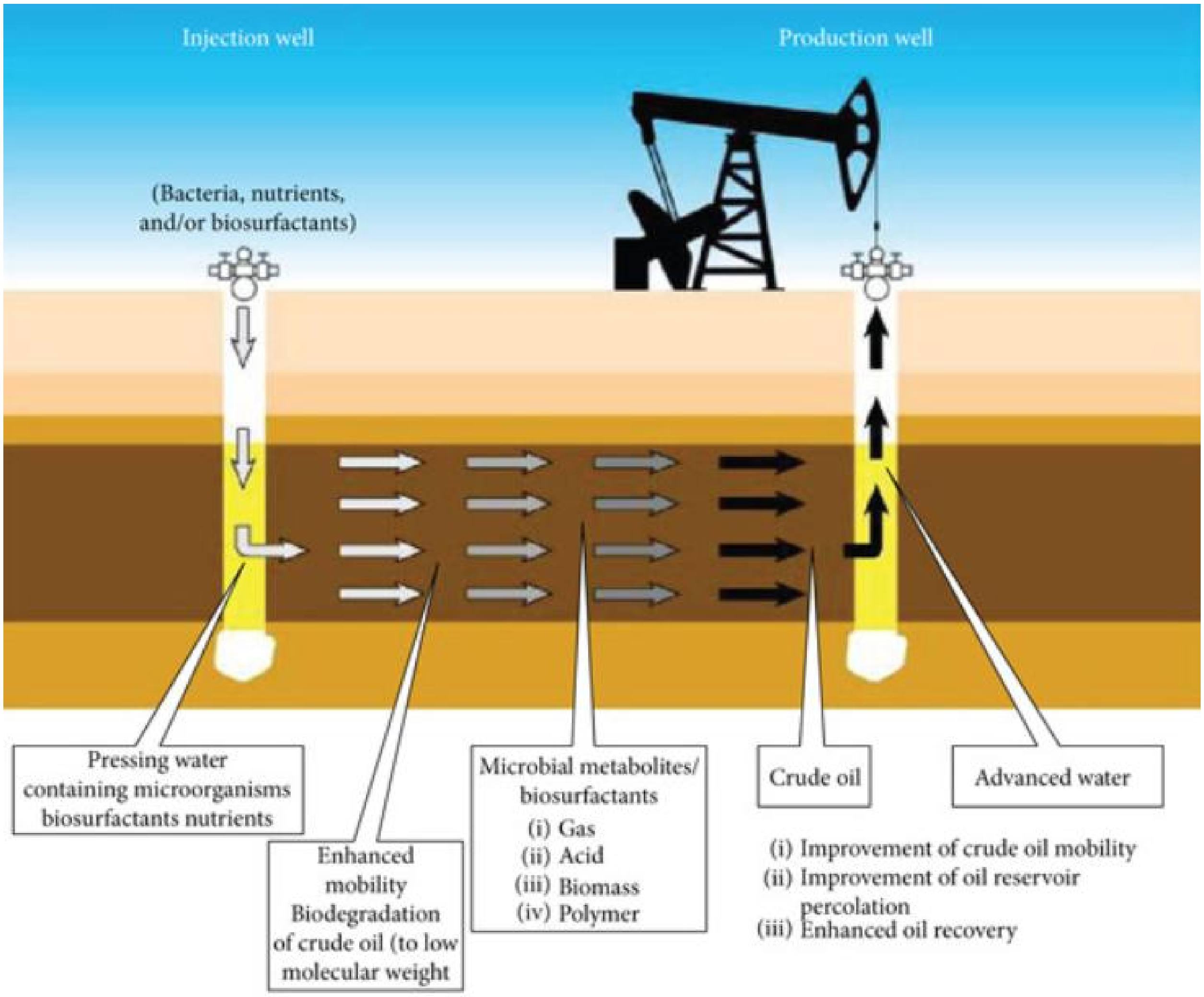
- Miscible Gas Injection - Use of CO_2 or hydrocarbon gas to mix with oil and reduce interfacial tension.



(Surajudeen 2023)

Figure 2.7 :

- Biological (Microbial) flooding – Use of microbes to alter the rock fluid interactions in the reservoir to increase recovery



(Haicheng 2019)

Figure 2.8 :

EOR methods are broadly categorized into four groups: thermal, chemical, gas-based and microbial flooding processes. Thermal methods, such as steam flooding and in-situ combustion, are used mainly in heavy oil reservoirs to reduce oil viscosity. Chemical methods involve injecting substances such as polymers, surfactants, or alkaline agents to modify fluid flow properties and reduce interfacial tension. Polymer flooding, for example, increases the viscosity of the displacing water, improving the mobility ratio and sweep efficiency (Abidin et al., 2012).

Gas-based EOR, including CO_2 injection and hydrocarbon gas flooding, enhances miscibility between oil and injected gas, improving displacement at the pore scale. CO_2 flooding is one of the most widely applied EOR techniques globally, offering both production enhancement and carbon sequestration benefits (Pope, 1980; Alvarado & Manrique, 2010).

Tertiary recovery can raise total recovery factors to 60% or more of the OOIP, depending on the reservoir characteristics, fluid properties, and economic conditions. However, challenges such as high implementation costs, environmental concerns, and technical complexities continue to limit its widespread application, especially in developing regions (Sheng, 2011).

Table 2.1: Comparison of oil recovery stages

Recovery Stage	Primary Energy Source / Mechanism	Typical Techniques	Recovery Efficiency (% of OOIP)
Primary	Natural reservoir energy (gas expansion, water drive, gravity drainage)	Solution gas drive, water drive, gas cap drive	5–15%
Secondary	Artificial pressure maintenance using injected fluids	Water flooding, gas injection	30–50%
Tertiary (EOR)	Chemical, microbial, thermal, or miscible processes	Polymer flooding, CO_2 injection, steam flooding	40–70%

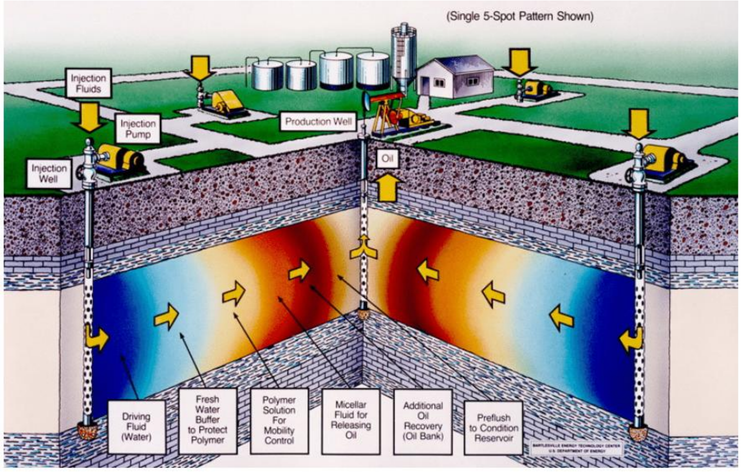
2.3 POLYMER FLOODING

2.3.1 INTRODUCTION

Polymer flooding is an enhanced oil recovery (EOR) technique under chemical flooding that involves the addition of high-molecular-weight, water-soluble polymers to the injection water to improve the macroscopic sweep efficiency of oil displacement therefore achieving a piston-like displacement of oil from areas of high residual saturation. The main goal is to increase the viscosity of the injected water, thereby reducing the water-oil mobility ratio making sure that oil is the more mobile fluid in the reservoir and improving displacement uniformity throughout the reservoir. This process is usually applied after secondary recovery stages, particularly after water-flooding when viscous fingering and high or early water breakthrough starts to occur, when oil production declines due to increasing water cut (Sheng, 2011).

2.3.2 MECHANISM OF POLYMER FLOODING

The primary mechanism of polymer flooding lies in its ability to control the mobility ratio between the displacing and displaced phases. The polymer molecules increase the viscosity of the injected water, which decreases the mobility ratio and improves sweep efficiency (Green & Willhite, 2018). In addition, polymer adsorption onto rock surfaces can partially reduce permeability in high-permeability zones, promoting better conformance and profile control (Sorbie, 1991).



(Do Quang 2014)

Figure 2.9: Chemical Flooding (Micellar -Polymer)

The main recovery mechanisms include:

1. Mobility control - improving the uniformity of the displacement front.
2. Profile modification - diverting injected fluids from high-permeability zones to low-permeability zones.
3. Increase in areal and vertical sweep efficiency – enhancing contact between injected water and trapped oil.

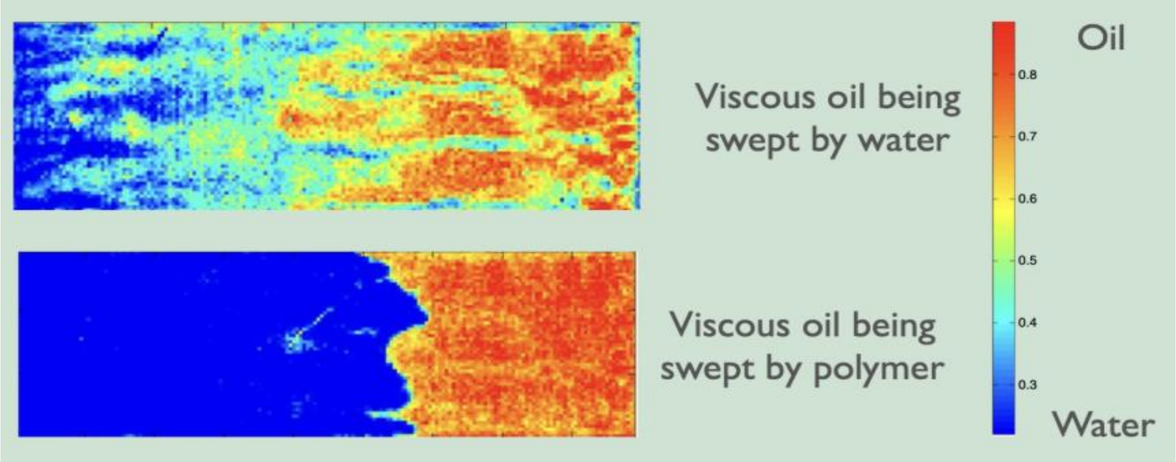


Figure 2.10: Comparison between conventional water flood and polymer flooding

2.3.3 TYPES OF POLYMERS USED

There are two main classifications of polymers used for EOR purposes, they are either biopolymers or synthetic polymers. The polymers commonly used in EOR applications must be water-soluble, stable under reservoir conditions, and capable of significantly increasing solution viscosity at low concentrations. The two most widely used polymer types are partially hydrolyzed polyacrylamide (HPAM) and biopolymers such as xanthan gum (Sheng, 2011; Wang et al., 2020).

Table 2.2: types of polymers used for EOR

Polymer Type	Source/Composition	Key Features
HPAM	Synthetic (polyacrylamide-based)	High viscosity; cost-effective; sensitive to salinity and temperature
Xanthan Gum (Biopolymer)	Microbial biopolymer	Excellent shear stability; more tolerant to salinity
Schizophyllan (Biopolymer)	Biopolymer from fungi	High temperature and salinity stability; biodegradable
Sulfonated Polyacrylamide	Modified synthetic polymer	Enhanced thermal and chemical resistance

2.3.4 SCREENING AND DESIGN CONSIDERATIONS

Screening and design of polymer flooding depend on reservoir and fluid characteristics such as temperature, salinity, oil viscosity, permeability, porosity, reservoir heteroginety and formation type. A successful polymer flood requires balancing polymer stability and injectivity while minimizing adsorption and degradation (Taber et al., 1997).

Table 2.3: screening criteria for an effective polymer flood

Parameter	Recommended Range	Remarks
Temperature	< 85°C	Above this, HPAM degradation increases
Formation Water Salinity	< 100,000 ppm TDS	High salinity reduces viscosity effectiveness
Oil Viscosity	10–150 Cp	Polymer flooding is ideal for moderate viscosity oils
Permeability	> 50 mD	Ensures injectivity and uniform polymer distribution
Rock Type	Sandstone preferred	Carbonates are less favorable due to adsorption issues

2.3.5 FIELD APPLICATIONS AND PERFORMANCE

Polymer flooding has been successfully implemented in many fields worldwide. The Daqing field in China is one of the most successful examples, achieving incremental oil recovery of up to 12% of OOIP over conventional water-flooding (Wang et al., 2020). Other significant applications include the Tambaredjo field (Suriname) and the Marmul field (Oman). Field-scale performance depends heavily on polymer concentration, injection rate, and reservoir heterogeneity.

Polymer flooding has been widely applied in various oil fields globally, with over 300 field applications reported worldwide. This enhanced oil recovery (EOR) method involves injecting a polymer solution into an oil reservoir to increase the amount of oil that can be extracted.

Performance Overview

The performance of polymer flooding in field applications has been promising, with reported incremental recovery ranging from 6% to 27%, averaging 21% of the original oil in place. Water cuts have been reduced to 4-39%, averaging 17%. These results demonstrate the potential of polymer flooding to significantly improve oil recovery and reduce water production.

Field Application Considerations

When designing a polymer flooding project, several factors need to be considered, including:

- Reservoir Properties: The polymer solution's viscosity and mobility control capabilities are affected by the reservoir's permeability, porosity, and temperature.
- Polymer Selection: The choice of polymer depends on the reservoir's properties, including temperature, salinity, and rock type.
- Injection Strategy: The injection rate, pressure, and volume of polymer solution need to be optimized to achieve maximum oil recovery.

2.3.6 ADVANTAGES AND LIMITATIONS

Advantages:

1. Improves volumetric sweep efficiency.
2. Reduces water cut and extends field life.
3. Compatible with existing water-flooding infrastructure.

Limitations:

1. Polymer degradation due to temperature, salinity, or shear.
2. High chemical costs.
3. Potential formation damage due to plugging or adsorption.

2.4 POLYMER FLOODING IN AFRICAN AND NIGERIAN CONTEXT

Polymer flooding has attracted significant attention in various African oil-producing countries due to its potential to enhance oil recovery in mature and heterogeneous reservoirs. Although its large-scale application remains limited compared to regions like North America and Asia, several African nations have undertaken laboratory investigations, simulation studies, and pilot projects to evaluate its feasibility (Sheng, 2011; Wang et al., 2020).

2.4.1 POLYMER FLOODING ACROSS AFRICA

In Africa, polymer flooding has seen practical interest mainly in North African regions such as Egypt and Algeria, where pilot tests and simulation studies have demonstrated incremental recoveries of 5–15% of OOIP (Abdallah et al., 2019). The maturity of the water-flooding infrastructure in these regions provides a suitable foundation for polymer flood expansion. Additionally, several studies in sub-Saharan Africa have highlighted the technique’s potential, although most efforts remain at the laboratory or pilot evaluation stages (Orodu et al., 2021).

2.4.2 POLYMER FLOODING IN NIGERIA

In Nigeria, polymer flooding remains in its early developmental phase. The majority of available data arises from research projects, laboratory experiments, and simulation studies performed on Niger Delta sandstone reservoirs. These studies consistently indicate that polymer flooding can significantly improve oil recovery, particularly in reservoirs with moderate oil viscosity and adequate permeability (Orodu et al., 2021; Emeh & Orodu, 2019). Simulation models show that polymer flooding can yield up to 15–20% incremental recovery over conventional water-flooding under optimized design parameters.

Despite the promising results, full-scale field deployment in Nigeria has been slow due to technical, operational, and economic barriers. Factors such as high formation water salinity, polymer degradation at elevated temperatures, and supply chain constraints remain significant challenges (Akinwumi et al., 2020).

2.4.3 CHALLENGES AND MITIGATION STRATEGIES IN NIGERIA

Recovering oil from underground reservoirs is a complex process due to the unique characteristics of each reservoir. The rock properties, fluid properties, and reservoir conditions all play a crucial role in determining the amount of oil that can be recovered.

The table below summarizes the key challenges encountered in polymer flooding within Nigerian and African reservoirs and provides possible mitigation strategies to enhance technical and economic feasibility.

Table 2.4: challenges and mitigation strategies as regards polymer flooding in nigeria

Challenges	Mitigation Strategies
High salinity and divalent ions (Ca^{2+}, Mg^{2+}) in formation water	Use sulfonated or hydrophobically-associating polymers; pre-treat brine or use seawater blends.
Polymer degradation due to temperature and shear	Use temperature-resistant polymers; optimize injection facilities to reduce shear stress.
High cost and logistic limitations	Develop local polymer production or regional supply chains to reduce import dependence.
Reservoir heterogeneity and permeability variation	Apply polymer-alternating-water (PAW) or surfactant-polymer flooding to improve conformance.
Adsorption and retention on rock surfaces	Conduct detailed core tests and preflushes to minimize adsorption losses.

2.4.4 OPPORTUNITIES AND FUTURE PROSPECTS

There is strong potential for polymer flooding in some of Nigeria's onshore and shallow offshore reservoirs, especially where existing waterfloods are mature. With improvements in polymer chemistry, local production capability, and enhanced reservoir characterization, polymer flooding could become a major tertiary recovery method in the Niger Delta. Collaborations between academia, industry, and government can further reduce cost and improve pilot-scale results.

2.5 HISTORY, PREVIOUS PROJECTS, CASE STUDIES, DEVELOPMENT, AND EXECUTION

The evolution of polymer flooding as a tertiary recovery technique represents one of the most important developments in chemical enhanced oil recovery (CEOR). The concept emerged in the early 1960s when petroleum engineers realized that water-flooding could be made more effective by increasing the viscosity of the injected water using polymers. This approach helped improve mobility control, reduce fingering, and displace trapped oil more uniformly. Initial field tests in North America demonstrated encouraging results, paving the way for global adoption. Over the following decades, polymer flooding matured from small pilot projects to full-field implementations, supported by advances in polymer chemistry, reservoir characterization, and injection technology.

The development of polymer flooding projects follows a multi-stage process involving laboratory screening, pilot design, full-field implementation, and post-injection monitoring. Laboratory tests establish polymer compatibility with reservoir rock and fluids, focusing on salinity, temperature, and shear stability. During pilot implementation, injection parameters such as polymer concentration, injection rate, and slug size are optimized. Execution requires surface facility adaptation including polymer dissolution units, filtration systems, and upgraded injection pumps to ensure reliable delivery. Post-deployment, real-time monitoring of pressure behavior, injectivity, and produced polymer concentration is essential for assessing project success and adjusting the injection strategy.

Several historic and contemporary case studies highlight the technical and economic feasibility of polymer flooding around the world:

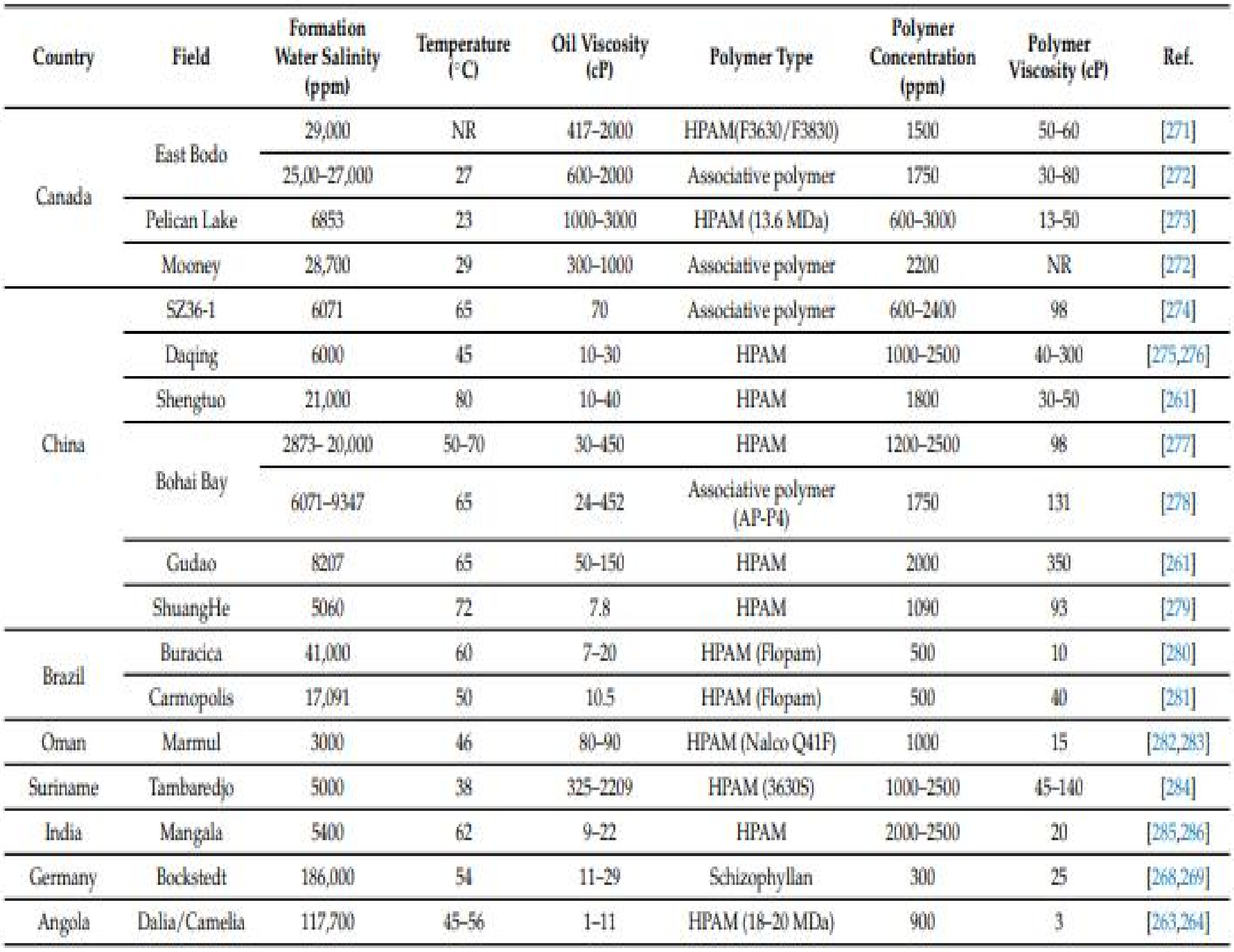
- Daqing Field, China: Perhaps the most successful polymer flooding project globally, Daqing began polymer injection in the early 1990s after extensive pilot testing. The field, characterized by high permeability (100–1000 mD) and moderate temperature (~45°C), used partially hydrolyzed polyacrylamide (HPAM) as the polymer. The project resulted in more than one billion barrels of incremental oil recovery and reduced water cut significantly. Continuous optimization in polymer composition and injection scheduling made Daqing a model for large-scale chemical EOR.
- Minnelusa Field, USA: One of the earliest commercial polymer floods took place in the 1960s at the Minnelusa reservoir in Wyoming. The project demonstrated that polymer addition could reduce water mobility, delay water breakthrough, and improve sweep efficiency. Though polymer degradation and mechanical issues limited long-term performance, this early effort established the scientific foundation for later projects.

- Middle East and North Africa: Several polymer flooding pilots were conducted in Egypt, Oman, and Algeria between the 1980s and 2000s. In Egypt’s Western Desert and Gulf of Suez, HPAM and biopolymer solutions were tested in sandstone formations with promising laboratory recovery factors of up to 20% incremental oil. These studies emphasized the importance of brine salinity control and injection water conditioning to prevent polymer precipitation.

- Angola Dalia Offshore Field: Operated by TotalEnergies, the Dalia deep-water field became Africa's first offshore polymer flooding pilot. The project demonstrated the practicality of polymer injection under high-pressure, high-temperature, and deep-water logistics constraints. Results showed that polymer injection could effectively enhance mobility control offshore, setting a precedent for similar EOR projects in West Africa.
- Nigeria Niger Delta Reservoirs: In Nigeria, polymer flooding remains primarily at the research and simulation stage. Studies by universities and institutions, including the University of Benin, have modeled polymer flooding under Niger Delta conditions — typically shallow to medium-depth sandstone reservoirs with moderate salinity and temperatures between 60°C and 85°C. Results consistently indicate 8–15% incremental recovery potential compared to water-flooding. Challenges remain in polymer sourcing, logistics, and regulatory approvals for field-scale deployment.

Table 2.5: Expanded summary of major polymer flooding case studies worldwide

Region / Field	Reservoir Type	Polymer Type	Temp / Salinity	Incremental Recovery / Key Result	Reference
Daqing Field, China	High-perm sandstone	HPAM	45°C / low–moderate salinity	>1 billion bbl additional oil; reduced water cut by 40%	Wang et al., 2011, SPE
Minnelusa, USA	Clastic sandstone	Polyacrylamide	40°C / low salinity	10–15% increase in recovery factor	Sandiford, 1964, JPT
Oman & Egypt pilots	Carbonate & sandstone	HPAM / Biopolymer	60–80°C / high salinity	Up to 20% incremental recovery (lab-scale)	Shehata, 2012, SPE
Dalia Field, Angola (offshore)	Deepwater sandstone	Modified HPAM	80°C / seawater salinity	Demonstrated offshore feasibility under deepwater conditions	Morel et al., 2012, SPE
Niger Delta, Nigeria	Deltaic sandstone	HPAM	70°C / moderate salinity	Simulated 8–15% incremental recovery; potential field pilot under review	Evans & Olabode, 2021, IJSTRE



Country	Field	Formation Water Salinity (ppm)	Temperature (°C)	Oil Viscosity (cP)	Polymer Type	Polymer Concentration (ppm)	Polymer Viscosity (cP)	Ref.
Canada	East Bodo	29,000	NR	417–2000	HPAM(F3630/F3830)	1500	50-60	[271]
		25,00–27,000	27	600–2000	Associative polymer	1750	30–80	[272]
	Pelican Lake	6853	23	1000–3000	HPAM (13.6 MDa)	600–3000	13–50	[273]
	Mooney	28,700	29	300–1000	Associative polymer	2200	NR	[272]
China	SZ36-1	6071	65	70	Associative polymer	600–2400	98	[274]
	Daqing	6000	45	10–30	HPAM	1000–2500	40–300	[275,276]
	Shengtuo	21,000	80	10–40	HPAM	1800	30–50	[261]
	Bohai Bay	2873- 20,000	50–70	30–450	HPAM	1200–2500	98	[277]
		6071–9347	65	24–452	Associative polymer (AP-P4)	1750	131	[278]
	Gudao	8207	65	50–150	HPAM	2000	350	[261]
	ShuangHe	5060	72	7.8	HPAM	1090	93	[279]
Brazil	Buracica	41,000	60	7–20	HPAM (Flopam)	500	10	[280]
	Carmopolis	17,091	50	10.5	HPAM (Flopam)	500	40	[281]
Oman	Marmul	3000	46	80–90	HPAM (Nalco Q41F)	1000	15	[282,283]
Suriname	Tambaredjo	5000	38	325–2209	HPAM (3630S)	1000–2500	45–140	[284]
India	Mangala	5400	62	9–22	HPAM	2000–2500	20	[285,286]
Germany	Bockstedt	186,000	54	11–29	Schizophyllan	300	25	[268,269]
Angola	Dalia/Camelia	117,700	45–56	1–11	HPAM (18–20 MDa)	900	3	[263,264]

Figure 2.11: Fundamentals and recent progress in the flow of water soluble polymers in a porous media for enhanced oil recovery", November 2002

CHAPTER THREE

METHODOLOGY

This chapter presents the methodology adopted for the evaluation of polymer flooding as an enhanced oil recovery (EOR) technique in a Nigerian sandstone reservoir. The methodology outlines the step-by-step approach used to design, construct, and simulate the reservoir model using CMG STARS (Computer Modelling Group's Steam, Thermal, and Advanced Processes Reservoir Simulator), which is widely used for thermal and chemical flooding processes (CMG, 2021). Each stage of the simulation process from grid construction and well configuration to polymer injection scheduling and model validation was carefully executed to ensure that the model accurately represents field conditions.

The primary objective of this chapter is to describe how various reservoir and fluid parameters were integrated into the simulation to assess the feasibility and performance of polymer flooding. The approach adopted combines both theoretical considerations and numerical simulation techniques, enabling the prediction of reservoir behavior under polymer injection (Sheng, 2011). Parameters such as grid geometry, polymer concentration, injection rate, boundary conditions, and relative permeability relationships were systematically defined to achieve realistic and reliable results.

In addition, this methodology follows a structured format that ensures clarity and reproducibility. Each section of this chapter ranging from the grid system setup to model validation addresses a specific component of the modeling process. This structure allows for a comprehensive understanding of the workflow used to simulate polymer flooding and evaluate its impact on oil recovery efficiency.

The data used for this study were obtained from an asset belonging to First exploration and petroleum development company (FIRST E&P) with their field reports, which is a representative sandstone reservoir from a Nigerian oil field. These data were selected to ensure the model parameters align with realistic field conditions typically encountered in the Niger Delta.

3.1 JUSTIFICATION OF RESERVOIR AS A CANDIDATE FOR POLYMER FLOODING

Before the implementation of polymer flooding in this study, it was important to assess whether the selected reservoir possessed the geological and fluid characteristics that make it suitable for polymer application. This step was necessary because polymer flooding, though highly effective, incurs additional chemical and operational costs; hence, applying it to an inappropriate reservoir would yield limited benefits. Therefore, a detailed evaluation of the rock and fluid properties was conducted to justify this reservoir as a viable candidate for polymer flooding.

3.1.1 EVALUATION OF RESERVOIR ROCK AND FLUID PROPERTIES

The selected reservoir is a sandstone formation with an average porosity of 20% (0.2) and moderate to high permeability a key indicator of good injectivity for polymer solutions. The initial pressure is 2299.2 psi, while the temperature is 157°F, both of which fall within the safe operational range for partially hydrolyzed polyacrylamide (HPAM) polymers. At this temperature, HPAM retains adequate viscosity and thermal stability over long injection periods.

The crude oil viscosity is approximately 5 cP, representing a moderately viscous oil. This range is ideal for polymer flooding because it allows mobility control without excessively high polymer concentration. The formation water salinity of 25,000–35,000 ppm also lies within the acceptable limit for polymer stability, as most HPAM polymers perform effectively below 50,000 ppm.

Before introducing polymer flooding, the base case (representing natural reservoir drive without any EOR method) was simulated. The production performance indicated a gradual decline in oil rate and reservoir pressure, revealing limited natural energy and low displacement efficiency. This observation provided an early indication that the reservoir could benefit from a mobility control process such as polymer flooding.

3.1.2 EVALUATION OF MOBILITY RATIO

To quantitatively assess the reservoir's potential response to polymer flooding, the mobility ratio (M) was evaluated for both the base case (normal reservoir flow) and the polymer flooding case. The mobility ratio of a reservoir shows how easily the displacing fluid (water) moves with respect to the displaced fluid (oil)

The mobility ratio is given by:

$M = ((k_{rw} / \mu_w) / (k_{ro} / \mu_o))$

where:

k_{rw} = relative permeability to water
k_{ro} = relative permeability to oil
μ_w = viscosity of water (or polymer solution)
μ_o = viscosity of oil

A mobility ratio less than 1 indicates stable displacement and improved sweep efficiency, while a value greater than 1 suggests an unstable displacement front and early breakthrough.

For the base case, with:

μ_w = 0.36 cP (viscosity of water at 157°F)

μ_o = 10 cP

k_rw = 0.3

k_ro = 0.8

M base = (0.3/0.36) / (0.8/5) = 0.833 / 0.16 ≈ 10.41

This value (>1) indicates an unfavorable mobility ratio and poor displacement efficiency under normal reservoir flow.

For the polymer flooding case, assuming the polymer injection increases the viscosity of the displacing fluid (polymer solution) to approximately 10 cP:

M polymer = (0.3/10) / (0.8/5) = 0.03 / 0.16 ≈ 0.375

This clearly shows that polymer flooding significantly improves the mobility ratio, reducing it well below 1, which promotes stable displacement and better sweep efficiency.

3.1.3 SUITABILITY ASSESSMENT

Based on the simulation input data and fluid characteristics, the reservoir meets the essential criteria for a successful polymer flooding project, as summarized in Table 3.1

Table 3.1 Selection criteria for polymer flooding

Parameter	Observed Value	Typical Requirement for Polymer Flooding	Suitability
Reservoir Type	Sandstone	Preferably sandstone with moderate to high permeability	✓ Suitable
Temperature	157°F	< 200°F for HPAM stability	✓ Suitable
Reservoir Pressure	2299.2 psi	Within operational range of polymer injectivity	✓ Suitable
Oil Viscosity	10 cP	2–30 cP (for effective mobility control)	✓ Suitable
Water Salinity	25,000–35,000 ppm	< 50,000 ppm for most HPAM polymers	✓ Suitable
Permeability	Moderate–High	≥ 100 mD preferred for injectivity	✓ Suitable
Mobility Ratio (Base)	10.41	< 1 desired	✗ Poor
Mobility Ratio (Polymer Case)	0.375	< 1 desired	✓ Excellent

Summary

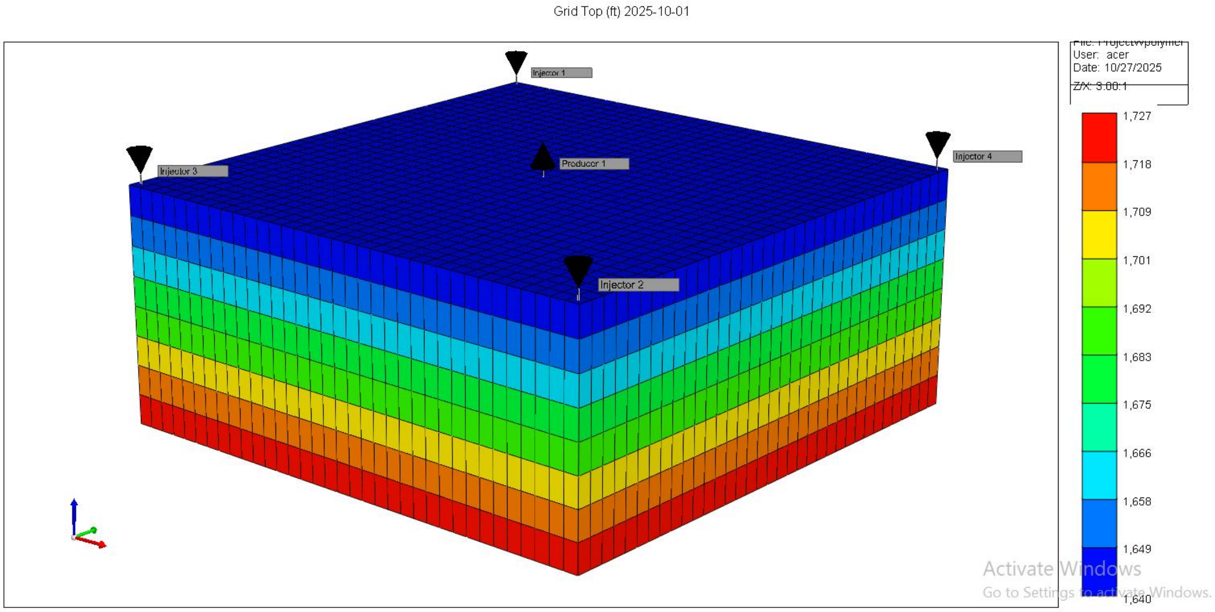
From the above analysis, the reservoir displays all the technical characteristics that qualify it as a strong candidate for polymer flooding. The polymer injection effectively modifies the mobility ratio, enhances sweep efficiency, and maintains favorable flow conditions. Consequently, applying polymer flooding in this reservoir is expected to yield significant recovery improvement compared to the base case scenario.

3.2 GRID SYSTEM AND GEOMETRY

The reservoir model for this study was constructed using the Quick Pattern Creation option in CMG Builder (STARS). A Normal 5-spot pattern configuration was employed to represent the injector–producer arrangement, which provides a balanced areal sweep efficiency typical of polymer flooding operations. The total modeled area covered 10 acres, corresponding to a square grid measuring approximately 661 ft. by 661 ft. The injector–producer spacing was maintained at about 467 ft. to ensure a realistic pressure gradient and effective polymer front propagation within the reservoir domain.

The model utilized a 3D Cartesian grid system with 35 × 35 × 8 grid blocks, giving a total of 9,800 cells. Each cell measured approximately 20 ft × 20 ft in the X and Y directions and 13 ft in the Z-direction. The reservoir thickness was set at 98 ft, with the top of the reservoir located at a depth of 1,640 ft. The formation dip angle was assumed to be 0°, representing a relatively horizontal sandstone reservoir structure typical of Nigerian oil fields.

This grid configuration ensured an optimal balance between computational efficiency and numerical accuracy. The chosen cell size and layer distribution were adequate to capture the saturation and pressure variations during polymer flooding, while maintaining reasonable simulation time. The configuration also supports sensitivity studies by allowing adjustments in grid density without compromising stability or precision.



(CMG 2021)

Figure 3.1 : Diagram of the grid geometry

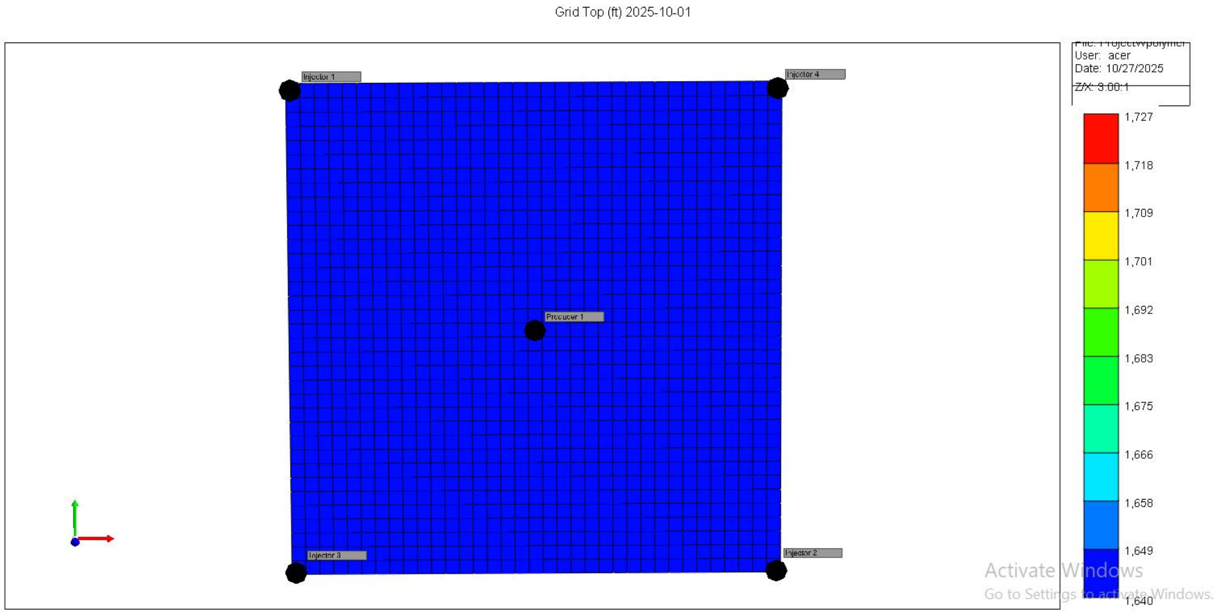
3.3 WELL CONFIGURATION

The well configuration plays a crucial role in determining the effectiveness of a polymer flooding operation. For this simulation, a five-spot well pattern was adopted, consisting of one producing well positioned at the center of the model and four injection wells placed symmetrically at the corners. This arrangement provides efficient areal sweep and helps achieve better reservoir contact during polymer injection.

The wells were designed as vertical wells, which is typical for sandstone reservoirs of moderate thickness. The distance between the central producer and each injector was set at approximately 467 ft. This spacing ensures an optimal pressure distribution and effective displacement of oil towards the producing well.

All eight reservoir layers were assumed to be perforated for both injection and production wells. This assumption was based on the reference simulation setup used for this study, where full-layer perforation was applied to promote uniform polymer flow throughout the reservoir. Full perforation also minimizes the risk of early breakthrough in any specific layer and enhances vertical sweep efficiency.

The five-spot configuration was selected for its simplicity, ease of simulation, and realistic representation of field-scale polymer flooding patterns. It also allows for symmetrical fluid movement and balanced injection pressures, which are essential for maintaining an effective mobility ratio and maximizing oil recovery efficiency.



(CMG 2021)

Figure 3.1 : well configuration of the simple reservoir model

3.4 POLYMER INJECTION SCHEME

Polymer flooding is an enhanced oil recovery (EOR) technique that improves the sweep efficiency of water-flooding by increasing the viscosity of the injected fluid, thereby reducing the mobility ratio between the displacing and displaced phases. The polymer injection scheme defines how the polymer solution is prepared, injected, and managed throughout the simulation period. It includes key parameters such as polymer type, polymer viscosity, salinity, concentration and duration. Proper design of these parameters ensures stable injectivity, reduced fingering, and maximum oil displacement efficiency (Sheng, 2011).

The polymer selected for this simulation is Partially Hydrolyzed Polyacrylamide (HPAM). HPAM is a synthetic polymer widely used in chemical flooding projects due to its favorable rheological properties, cost-effectiveness, and compatibility with sandstone reservoirs. It provides substantial viscosity enhancement to injection water even at low concentrations, which improves the mobility ratio and enhances macroscopic sweep efficiency. Although HPAM is susceptible to salinity and temperature degradation, it remains the most preferred polymer for onshore Nigerian reservoirs because of its availability, injectivity, and well-understood behavior under various reservoir conditions (Zhao et al., 2019).

Table 3.1 shows a comparative summary of HPAM with other polymers considered for EOR applications.

Property	HPAM	Xanthan Gum	Schizophyllan (Biopolymer)
Salinity Tolerance	Moderate (up to 20,000 ppm)	High (>35,000 ppm)	High (>40,000 ppm)
Temperature Stability	Moderate (<80°C)	Good (<90°C)	Excellent (<100°C)
Viscosity Enhancement	High	Moderate	Very High
Biodegradability	Low	High	High
Cost	Low	Moderate	High
Injectivity	High	Moderate	Moderate
Common Reservoir Type	Sandstone	Carbonate/Sandstone	Sandstone

From the comparison above, HPAM offers an optimal balance between cost, injectivity, and viscosity enhancement. Although biopolymers such as Schizophyllan demonstrate superior salinity and temperature tolerance, their higher cost and limited commercial availability make

HPAM a more practical choice for large-scale implementation in Nigerian reservoirs (Delamaide et al., 2014).

In this simulation, the polymer concentration was fixed at 1500 ppm to maintain a constant viscosity enhancement throughout the injection period. The injection rate was maintained at 33.5 bbl/day for a continuous polymer flood lasting 30 years. The injected polymer solution salinity was kept at 2000 ppm to prevent polymer precipitation due to the relatively high formation water salinity of 25,000–35,000 ppm. A total polymer slug size of 1.0 PV was assumed, representing a continuous polymer injection scheme without alternating water slugs. Polymer retention, degradation, and mechanical shear effects were not explicitly modeled due to insufficient field data.

Table 3.2 summarizes the polymer injection parameters used in this study.

Parameter	Value / Description
Polymer Type	HPAM (Partially Hydrolyzed Polyacrylamide)
Polymer Concentration	1500 ppm (constant)
Injection Rate	33.5 bbl/day
Injection Scheme	Continuous polymer flooding
Duration	30 years
Polymer Slug Size	1.0 PV (continuous injection)
Injected Polymer Salinity	2000 ppm
Reservoir Salinity	25,000–35,000 ppm
Retention/Degradation	Not modeled due to unavailable data

3.5 SIMULATION TIMING AND BOUNDARY CONDITIONS

Simulation timing and boundary conditions are critical parameters that define the operational framework of a numerical reservoir model. The total simulation time determines the period over which reservoir performance is evaluated, while boundary conditions specify how the reservoir interacts with its surroundings. Proper definition of these parameters ensures realistic modeling of pressure behavior, fluid flow, and production performance throughout the polymer flooding process (CMG STARS User Guide, 2021).

In this study, the total simulation time was set to 30 years, representing the entire period of polymer flooding from 2025 to 2055. This duration was chosen to evaluate both the short-term and long-term performance of the polymer injection process, including polymer propagation, oil displacement efficiency, and eventual production decline. The simulation time-step control was adaptive, allowing the simulator to automatically adjust time steps based on changes in pressure and saturation gradients during the injection process.

Boundary conditions were defined to represent the physical limits of the reservoir system and its interaction with external drives. The model included both a gas cap and an underlying aquifer to represent realistic reservoir behavior. A small gas cap with a gas cap ratio of 0.03 was modeled at the top of the reservoir, while an active aquifer was defined at the base to simulate natural water influx. The lateral boundaries of the reservoir were assumed to be no-flow boundaries to confine the simulation within the defined grid limits. These settings ensured that the modeled reservoir maintained pressure support from both gas and water drive mechanisms while avoiding unrealistic external pressure effects.

The initial and operating reservoir conditions were maintained at an average pressure of 2299.2 psi and a temperature of 157°F. These conditions were consistent with the field data obtained during the initialization stage of the model. The polymer flooding process was carried out under isothermal conditions, implying that the temperature was constant throughout the simulation, and thermal effects were not explicitly considered.

Table 3.3 summarizes the main simulation timing and boundary condition parameters used in this study.

Parameter	Value / Description
Total Simulation Time	30 years (2025–2055)
Boundary Type	No-flow (closed lateral boundaries)
Aquifer Presence	Yes (active bottom aquifer)
Gas Cap Ratio	0.03 (small gas cap at reservoir top)
Initial Reservoir Pressure	2299.2 psi
Reservoir Temperature	157°F (isothermal conditions)
Time Step Control	Adaptive (auto-adjusted by CMG STARS)

3.6 RELATIVE PERMEABILITY AND CAPILLARY PRESSURE

In this section, the relative permeability and capillary pressure relationships used in the polymer flooding simulation are discussed. These parameters describe the multiphase flow behavior of oil, water, and polymer solution within the porous reservoir rock. For this model, Corey-type correlations were adopted due to the absence of laboratory-measured data. The Corey formulation is a widely used empirical model that relates relative permeability to the phase saturation using power-law relationships.

3.6.1 RELATIVE PERMEABILITY

The Corey-type relative permeability model was selected to describe the relationship between water and oil saturations in the reservoir. The model assumes a smooth, non-hysteretic flow relationship between the wetting and non-wetting phases. Based on the CMG STARS setup, the initial water saturation (Swi) was defined as 0.16, and the residual oil saturation (Sor) was estimated to be approximately 0.40. The effective water and oil relative permeabilities were expressed as functions of normalized water saturation, as shown in Table 4.3.

Table 3.4: Corey-type relative permeability data used in the CMG STARS polymer flooding model.

Water Saturation (Sw)	krw (Water Rel. Perm.)	kro (Oil Rel. Perm.)
0.16	0	0.85
0.2	0.00192744	0.74707
0.24	0.00770975	0.650781
0.28	0.0173469	0.561133
0.32	0.030839	0.478125
0.36	0.0481859	0.401758
0.4	0.0693878	0.332031
0.44	0.0944444	0.268945
0.48	0.123356	0.2125
0.52	0.156122	0.162695
0.56	0.192744	0.119531
0.6	0.23322	0.0830078
0.64	0.277551	0.053125
0.68	0.325737	0.0298828
0.72	0.377778	0.0132812
0.76	0.433673	0.00332031
0.8	0.493424	0
0.9	0.659666	0
1	0.85	0

3.6.2 CAPILLARY PRESSURE

Capillary pressure was also modeled using the Corey-type correlation, which defines the pressure difference between the non-wetting (oil) and wetting (water) phases as a function of effective water saturation. The capillary pressure curve follows a drainage-type behavior, representing conditions where water displaces oil during polymer injection. Hysteresis effects were neglected to simplify the modeling process. This assumption is acceptable in synthetic polymer flooding studies where the main objective is to evaluate displacement efficiency rather than capillary trapping dynamics.

3.6.3 JUSTIFICATION FOR THE COREY MODEL

The choice of the Corey-type model was primarily due to its simplicity, flexibility, and compatibility with CMG STARS. It enables a realistic representation of relative permeability behavior without requiring laboratory-derived parameters, which are often unavailable in early-stage feasibility studies. The model also allows easy adjustment of endpoint and curvature parameters to match typical sandstone reservoir conditions.

3.7 MODEL INITIALIZATION AND INPUT PARAMETERS

Model initialization and input parameter definition are essential steps in developing a reliable simulation framework for polymer flooding. In this study, initialization was carried out using a depth-based pressure gradient approach in CMG STARS, allowing the reservoir to reach hydrostatic equilibrium before polymer injection. The initialization process ensured that pressure, temperature, and saturation distributions reflected realistic reservoir conditions representative of Nigerian sandstone formations.

3.7.1 RESERVOIR INITIALIZATION METHOD

The reservoir model was initialized in CMG STARS using the pressure–depth function. This approach automatically distributed pressure values according to the specified reservoir depth, ensuring hydrostatic equilibrium. Since the exact elevation data were not available, a depth-based initialization was chosen as a practical assumption for a homogenous sandstone reservoir. This method is commonly applied in polymer flooding studies where vertical pressure gradients dominate over lateral variations.

3.7.2 INPUT PARAMETERS USED FOR INITIALIZATION

The key input parameters used for initializing the polymer flooding model are summarized in Table 4.7. These values were either derived from field data, literature, or assumed based on typical reservoir conditions found in onshore Nigerian sandstone formations.

Table 3.5 shows the reservoir rock and fluid properties

Parameter	Symbol / Unit	Value / Description
Initial Pressure	Pi (psi)	2299.2
Temperature	T (°F)	157
Initial Water Saturation	Swi	0.16
Porosity	φ	0.20
Permeability	k (mD)	600
Oil Viscosity	μo (cP)	5
Gas Cap Ratio	Rg	0.03
Rock Compressibility	Cr (1/psi)	4.5×10^{-6}
Original Oil in Place	OOIP (MMSTB)	36.03
Reservoir Salinity	ppm	25,000–35,000
Polymer Solution Salinity	ppm	2,000
Elevation / Depth Reference	ft	Depth-based initialization (assumed)

3.7.3 MODEL CONSISTENCY AND VERIFICATION

After initialization, CMG STARS automatically computed the pressure and saturation distribution across the reservoir layers. The model was verified to ensure that the initial water saturation matched the input Swi value of 0.16 and that oil and water volumes were in equilibrium. No production or injection wells were activated during initialization to prevent artificial fluid movement. The initialization step confirmed that the model setup accurately represented the initial reservoir conditions prior to polymer flooding.

Summary

In summary, the model initialization phase provided a stable and realistic starting point for simulating polymer flooding. The chosen input parameters and assumptions were consistent with field-representative data, ensuring that subsequent simulation steps could accurately capture the impact of HPAM polymer injection on reservoir performance.

3.8 SIMULATION PROCEDURE

This section outlines the step-by-step approach used to perform the polymer flooding simulation using CMG STARS (2021 version). The simulation procedure involved the preparation of reservoir input data, initialization, well definition, polymer injection control, and output analysis. The overall objective was to evaluate the effectiveness of polymer flooding in improving oil recovery under Nigerian sandstone reservoir conditions.

3.8.1 MODEL SETUP AND INITIALIZATION

The model was initialized based on the previously defined reservoir and fluid parameters. The grid geometry, rock and fluid properties, and well configurations were all specified using a Cartesian grid system with six layers representing the heterogeneous nature of the reservoir. The initial conditions, such as pressure (2299.2 psi), temperature (157 °F), water saturation (Swi = 0.16), and porosity (0.20), were assigned before simulation to ensure a realistic representation of reservoir conditions. The model was then initialized to determine the original oil in place (OOIP) and ensure fluid saturations were consistent across all layers.

3.8.2 DEFINITION OF WELLS AND BOUNDARY CONDITIONS

Five vertical wells were defined in the model: one producer and four injectors, configured in a five-spot pattern. The injector wells were located symmetrically at the corners of the grid, while the producer was placed at the center. All wells were completed to a depth of 1000 ft, consistent with the reservoir top. A no-flow boundary condition was applied along the lateral grid boundaries to ensure that all flow remained within the model domain, while the top and bottom boundaries were maintained at constant temperature and pressure.

3.8.3 POLYMER INJECTION AND SIMULATION CONTROL

Polymer injection was implemented as a continuous flooding operation throughout the 30-year simulation period. The polymer used was HPAM with a constant concentration and an injection rate of 33.5 bbl/day. The polymer solution salinity was set at 2000 ppm to prevent polymer precipitation and degradation, as HPAM is sensitive to high salinity environments. The simulation was executed using a fully implicit formulation to ensure numerical stability. Time steps were automatically adjusted to maintain convergence during periods of rapid change in fluid saturation or pressure.

3.8.4 MONITORING AND OUTPUT ANALYSIS

Throughout the simulation, key parameters were monitored, including oil production rate, water cut, cumulative oil recovery, bottom-hole pressure, and polymer concentration at both injector and producer wells. The results were recorded at defined time intervals and exported for analysis. Post-processing was conducted using CMG Results and CMOST tools to visualize saturation fronts, polymer propagation, and pressure distribution. Graphical outputs, such as oil recovery factor versus time and water cut curves, were used to interpret the reservoir response to polymer flooding.

3.8.5 SUMMARY OF SIMULATION WORKFLOW

In summary, the simulation workflow followed these main steps:

1. Input of rock, fluid, and polymer properties.
2. Definition of grid geometry and well locations.
3. Initialization of pressure, temperature, and saturation conditions.
4. Specification of injection and production controls.
5. Execution of the CMG STARS simulation.
6. Monitoring of performance indicators and visualization of results.

This systematic approach ensured that the simulation captured both the physical and chemical interactions associated with polymer flooding and provided insight into its effectiveness under Nigerian sandstone reservoir conditions.

CHAPTER FOUR

RESULTS AND DISCUSSION

4.1 INTRODUCTION

This chapter presents the simulation results obtained from the CMG STARS model for two reservoir development scenarios: the base case (without any enhanced oil recovery method) and the polymer flooding case. The results are analyzed comparatively to evaluate the impact of polymer injection on reservoir performance.

Key production parameters such as oil production rate, bottomhole pressure (BHP), and water cut were evaluated to understand the overall reservoir response and fluid displacement efficiency under both conditions. Comparative plots were generated to visualize performance differences and to assess the feasibility of polymer flooding as an enhanced oil recovery (EOR) technique for the studied Nigerian sandstone reservoir.

Time (day)	**Date**	**Cumulative Gas SC (ft3)**	**Cumulative Oil SC (bbl)**	**Cumulative Water SC (bbl)**	**Gas Oil Ratio SC (ft3/bbl)**	**Gas Rate SC - Yearly (ft3/day)**	**Oil Rate SC - Yearly (bbl/day)**
-273	2025-Jan-01 00:00:00					0	0
92	2026-Jan-01 00:00:00	6260.977051	2575.99707	0.003996269	2.429670811	17.15336227	7.057526588
457	2027-Jan-01 00:00:00	31100.10938	12795.98242	0.017834226	2.430747509	68.05241394	27.99996185
822	2028-Jan-01 00:00:00	55943.78125	23015.9707	0.02885974	2.430982113	68.06484985	27.99996758

1188	2029-Jan-01 00:00:00	80857.1875	33263.96094	0.037986316	2.431103706	68.06941986	27.99996948
1553	2030-Jan-01 00:00:00	105703.5	43483.94922	0.04549361	2.431181192	68.07208252	27.9999752
1918	2031-Jan-01 00:00:00	130550.4766	53703.94531	0.051627804	2.431237459	68.07391357	27.99997902
2283	2032-Jan-01 00:00:00	155397.9531	63923.93359	0.056572631	2.431280136	68.07528687	27.99998283
2649	2033-Jan-01 00:00:00	180313.875	74171.92969	0.060529217	2.431308508	68.07627869	27.99998856
3014	2034-Jan-01 00:00:00	205161.8906	84391.92969	0.063646749	2.431313753	68.0767746	27.99998856
3379	2035-Jan-01 00:00:00	230009.6563	94611.92188	0.066134468	2.431240797	68.07601166	27.99999046
3744	2036-Jan-01 00:00:00	254855.4063	104831.9141	0.068226807	2.430969477	68.07062531	27.99998474
4110	2037-Jan-01 00:00:00	279767.625	115079.9063	0.069886893	2.430889368	68.06613922	27.99998474
4475	2038-Jan-01 00:00:00	304595.25	125293.625	6.325555801	2.430730104	68.0209198	27.98277473
4840	2039-Jan-01 00:00:00	329342.5938	135475.0625	44.9948082	2.430568218	67.80095673	27.8943615
5205	2040-Jan-01	353984.7813	145613.7656	126.295639	2.430453777	67.51279449	27.7772522

	00:00:00						
5571	2041-Jan-01 00:00:00	378577.5	155732.6406	255.5025787	2.430312634	67.19322205	27.64719391
5936	2042-Jan-01 00:00:00	402934.375	165755.1406	452.9997253	2.430126429	66.73117828	27.45890045
6301	2043-Jan-01 00:00:00	426996.0625	175657.2656	771.2767334	2.429737091	65.92242432	27.1291275
6666	2044-Jan-01 00:00:00	449856.9375	185067.875	1580.826538	2.428912163	62.63252258	25.7824707
7032	2045-Jan-01 00:00:00	470837.7188	193706.7969	3190.523438	2.428467989	57.3245697	23.60360718
7397	2046-Jan-01 00:00:00	490338.25	201737.0938	5380.963379	2.428298473	53.42606354	22.0008316
7762	2047-Jan-01 00:00:00	508871.1875	209369.2969	7968.790527	2.42821455	50.77507782	20.91015625
8127	2048-Jan-01 00:00:00	526668.625	216698.8438	10859.1875	2.428167343	48.76026917	20.08093262
8493	2049-Jan-01 00:00:00	543924.0625	223805.2656	14000.8418	2.428137779	47.14604568	19.41644669
8858	2050-Jan-01 00:00:00	560633.375	230686.8438	17339.25195	2.428117275	45.77893448	18.85360336
9223	2051-Jan-01 00:00:00	576914.125	237391.9219	20854.12695	2.428102493	44.60469437	18.37014008

9588	2052-Jan-01 00:00:00	592796.6875	243933.1094	24532.95508	2.428088903	43.51386261	17.92098427
9954	2053-Jan-01 00:00:00	608351.625	250339.375	28374.66797	2.428071022	42.49991608	17.50350761
10319	2054-Jan-01 00:00:00	623491.5	256574.7344	32359.37305	2.428051949	41.47905731	17.08320045
10684	2055-Jan-01 00:00:00	638224.1875	262642.4688	36511.65234	2.428023338	40.36350632	16.62392044

Table 4.1 :The provided data represents the cumulative production data for gas oil and water

4.2 Field Oil Production Rate

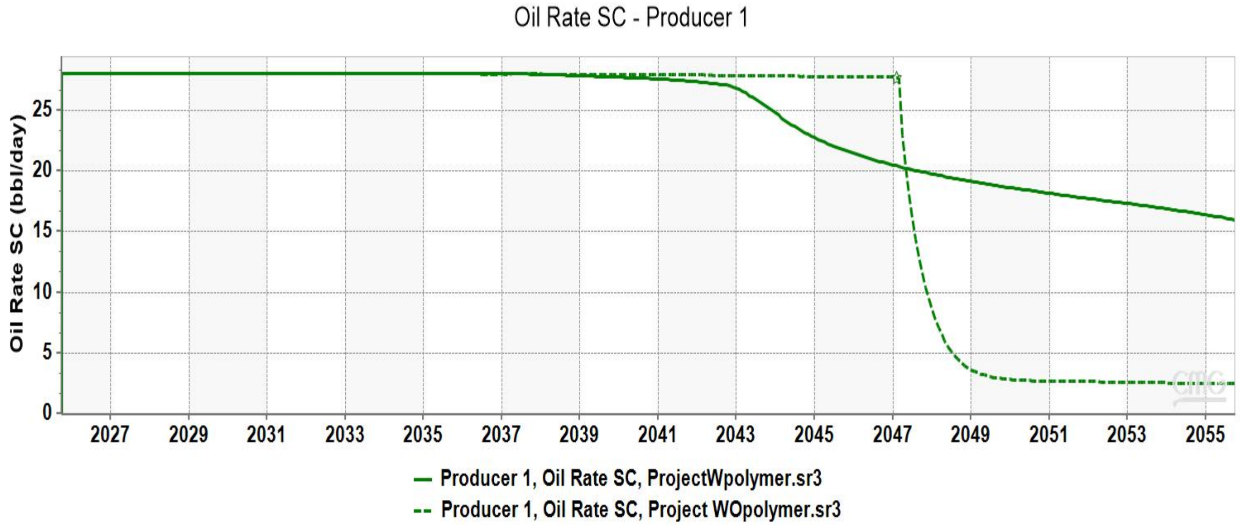


Figure 4.1: Comparison of field oil production rate for the base case (projectWOpolymer) and polymer flooding case (projectWpolymer).

Figure 4.1 presents the simulated field oil production rate (FOPR) for both the base case and the polymer flooding case over the 30-year production period. Initially, both scenarios display a high oil rate due to reservoir pressure and fluid drive mechanisms. However, as time progresses, the performance trends diverge significantly.

The base case shows a rapid decline in oil rate after the early years of production, indicating the depletion of movable oil and poor sweep efficiency. In contrast, the polymer flooding case maintains a relatively higher and more stable oil production rate throughout the mid and later years of the simulation.

The sustained oil rate in the polymer flooding scenario is attributed to the improved mobility control provided by the polymer solution. The injected polymer increases the viscosity of the displacing phase (injected water), thereby reducing the mobility ratio and enhancing the areal and vertical sweep efficiency. This prevents premature water breakthrough and promotes more uniform displacement of oil toward the production wells.

The results demonstrate that polymer flooding improves the reservoir’s productivity and extends the plateau period of oil production. Around the late simulation years (2048–2055), the polymer flooding case still exhibits appreciable oil output, while the base case shows a pronounced decline. This behavior highlights the effectiveness of polymer flooding in delaying production decline and increasing ultimate oil recovery from the sandstone reservoir.

4.3 Bottomhole Pressure (BHP)

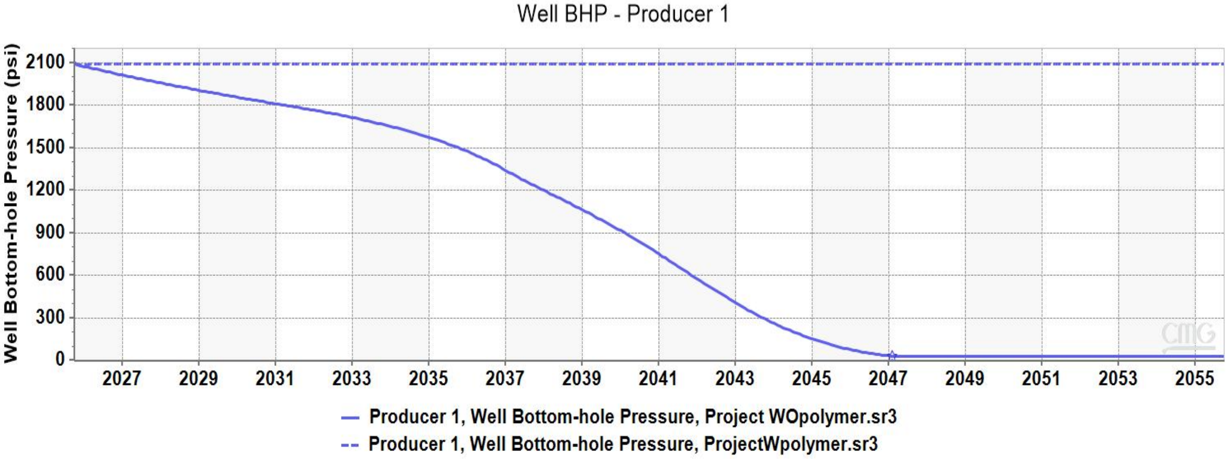


Figure 4.2: Comparison of bottomhole pressure for the base case and polymer flooding case.

Figure 4.2 illustrates the variation of bottomhole pressure (BHP) for both the base case and polymer flooding scenarios over the 30-year production period. The polymer flooding case maintained a relatively stable BHP of approximately 2100 psi throughout the simulation period, while the base case exhibited a gradual and continuous decline in pressure until about 2047, when reservoir pressure was almost completely depleted.

The stability observed in the polymer flooding case can be attributed to the enhanced pressure support provided by the injected polymer solution. The polymer increases the viscosity of the injected fluid, improving the reservoir's ability to transmit pressure uniformly and maintain higher reservoir energy levels. This prevents premature pressure drops in the producing wells and helps sustain consistent fluid flow rates

Conversely, the base case operating without any enhanced recovery technique experienced progressive pressure depletion due to unrestricted water mobility and poor sweep efficiency. As the reservoir fluids were produced, the pressure gradient weakened, leading to declining production performance and eventual pressure exhaustion near the end of the simulation period.

This result confirms that polymer flooding not only improves oil recovery efficiency but also plays a vital role in pressure maintenance. The polymer's viscosity control mechanism reduces the loss of driving energy, ensuring better reservoir management and prolonging the productive life of the reservoir.

4.4 Water Cut Analysis for Polymer Flooding in Nigerian Sandstone Reservoir

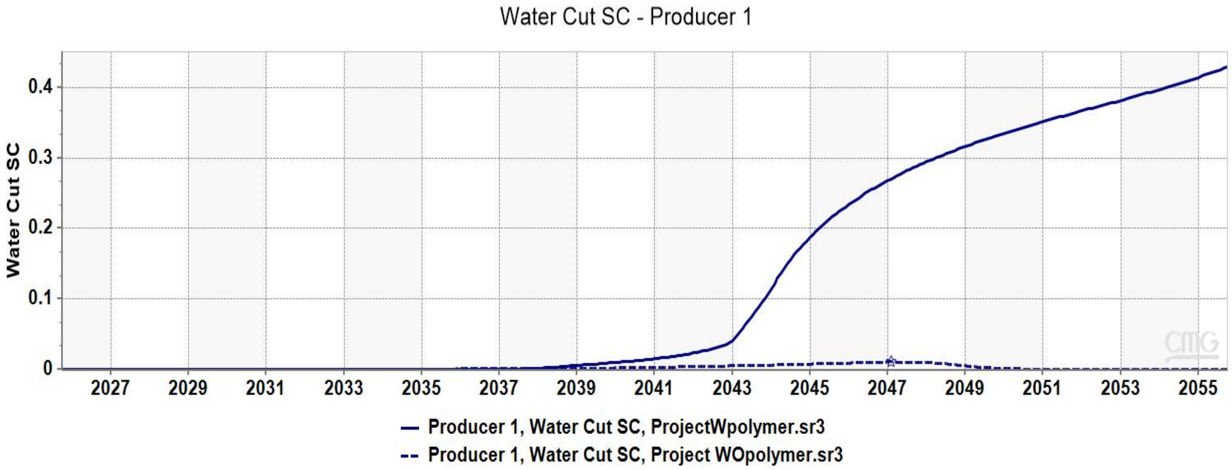


Figure 4.3: Water Cut (SC) versus Time for Producer 1 under Polymer Flooding Simulation.

Figure 1 shows the variation of water cut (SC) with time for Producer 1 in the simulated polymer flooding scenario. The graph illustrates the performance of the reservoir from the start of production in 2025 to the end of the simulation period in 2055. Initially, the water cut remains very low, indicating that oil production is dominant and minimal water is being produced. From around 2038, there is a noticeable increase in the water cut in the polymer flooding case, suggesting the breakthrough of injected polymer solution or increased water production due to displacement of oil from the reservoir matrix. Between 20438 and 2048, the water cut rises sharply, reaching approximately 0.3, signifying a significant influx of water at the producer well. After 2048, the water cut continues to increase gradually, stabilizing around 0.4 by 2055. This gradual rise indicates that the reservoir is entering a mature production phase where water handling becomes critical.

The results suggest that polymer flooding was effective enhancing oil recovery before water dominance set in. The observed water cut trend demonstrates a controlled displacement process, where the polymer solution improved the mobility ratio, reduced viscous fingering, and maintained sweep efficiency over time. However, as the reservoir approached late production years, the increasing water cut indicates the need for proper water management strategies to sustain economic oil production.

CHAPTER FIVE

CONCLUSION AND RECOMMENDATIONS

5.1 CONCLUSION

This research project investigated the feasibility and performance of polymer flooding as an enhanced oil recovery (EOR) technique in sandstone reservoirs, with particular reference to Nigerian oil field conditions. The simulation was performed using the CMG-STARS simulator to compare a base case scenario (without EOR application) and a polymer flooding case in which a 1500 ppm hydrolyzed polyacrylamide (HPAM) polymer solution was injected under the specified reservoir conditions. The analyses were focused on field oil production rate, bottom-hole pressure (BHP), water cut, and overall recovery efficiency over a 30-year simulation period (2025–2055).

The results demonstrated a clear improvement in reservoir performance following polymer injection. While the base case showed a continuous decline in pressure and oil production until depletion around the year 2047, the polymer flooding case maintained a relatively stable average pressure of about 2100 psi throughout the production period. This stability was attributed to the polymer's ability to improve mobility control, reduce viscous fingering, and enhance areal sweep efficiency.

The cumulative oil production for the base case was approximately 17.8 million stock tank barrels (MMSTB), whereas the polymer flooding case achieved 23.6 MMSTB, representing an incremental recovery of about 5.8 MMSTB (32.6% increase). This improvement translated to a 16.1 percentage-point increase in recovery factor, confirming the effectiveness of polymer flooding under the given reservoir conditions. Additionally, the polymer injection delayed water breakthrough and reduced the final water cut from 89% (base case) to 68% (polymer case), further highlighting its ability to control excessive water production.

The findings of this study align with global and regional field experiences, where polymer flooding has proven effective in moderately viscous oil reservoirs and sandstone formations. Under Nigerian reservoir conditions, where temperature, salinity, and heterogeneity often challenge conventional water-flooding, polymer injection presents a viable and cost-effective EOR method capable of increasing ultimate recovery and prolonging the productive life of mature fields.

Beyond the immediate findings, this work reinforces the importance of adopting EOR technologies tailored to local reservoir conditions. With Nigeria's large inventory of brown and mature fields, the implementation of polymer flooding can contribute to national oil recovery targets, reduce the need for new exploration, and promote sustainable energy production. Moreover, the integration of simulation tools like CMG-STARS into design and optimization workflows offers a reliable means to predict reservoir response and make data-driven operational decisions.

In conclusion, polymer flooding has been shown to be a technically feasible and operationally beneficial enhanced oil recovery method for Nigerian sandstone reservoirs. Its potential for improving pressure maintenance, increasing oil recovery, and managing water production makes it a strategic candidate for field-scale implementation. Future research and pilot studies should therefore focus on optimizing polymer concentration, injection rates, and compatibility with reservoir conditions to ensure maximum recovery and economic efficiency.

5.2 RECOMMENDATIONS

Based on the findings and conclusions derived from this study, the following recommendations are made for research, field development, and policy implementation:

1. Field Pilot Implementation:

It is recommended that polymer flooding be implemented as a pilot project in one of Nigeria's mature sandstone reservoirs. This would help validate the simulation results under actual field conditions and provide data for scaling up to full-field applications.

2. Optimization of Polymer Properties:

Future studies should explore the influence of polymer type, concentration, and molecular weight on oil recovery efficiency. Laboratory core flooding experiments and sensitivity analyses can be used to identify the most suitable polymer formulations for Nigerian reservoirs.

3. Salinity and Temperature Control:

Since HPAM polymers are sensitive to high salinity and temperature, it is recommended to evaluate polymer degradation under varying reservoir conditions. Field formulations should include stabilizers or alternative co-polymers designed to withstand harsh chemical environments.

4. Economic Feasibility Analysis:

Before large-scale deployment, a comprehensive techno-economic analysis should be conducted. This should include polymer costs, injection facility requirements, and long-term production gains to ensure economic viability and return on investment.

5. Integration with Other EOR Methods:

Polymer flooding can be combined with other EOR methods such as surfactant flooding or alkaline-surfactant-polymer (ASP) flooding for synergistic effects. These hybrid approaches should be investigated for their potential to further increase recovery efficiency in challenging reservoirs.

6. Capacity Building and Training:

The adoption of polymer flooding technology requires skilled personnel. Nigerian operators and research institutions should invest in capacity building through specialized training, workshops, and academic collaborations focused on EOR simulation, laboratory evaluation, and field implementation.

7. Policy and Regulatory Support:

Government agencies and energy policymakers should develop frameworks that encourage investment in EOR projects. Incentives such as tax reliefs, research funding, and technology transfer programs would facilitate the adoption of polymer flooding and other EOR methods across the Nigerian oil industry.

8. Environmental Management:

Although polymer flooding is generally environmentally friendly, proper management of produced fluids and chemical residues is essential. Field operations should follow environmental best practices to prevent contamination of surface and subsurface water resources.

9. Further Simulation Studies:

Additional numerical simulations should be carried out using different grid resolutions, well patterns, and injection strategies. These studies will improve understanding of fluid behavior under polymer injection and provide a basis for optimizing recovery performance.

10. Research Collaboration:

Universities, research centers, and oil companies in Nigeria should collaborate on pilot projects and data sharing initiatives. This would accelerate local innovation and enhance the country's technical capability in advanced EOR applications.

Overall, polymer flooding presents a technically sound, economically feasible, and environmentally sustainable approach to enhanced oil recovery. With the right combination of research, policy, and industry cooperation, its adoption can significantly boost Nigeria's oil production efficiency and contribute to long-term energy security.

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APPENDIX

Reservoir and Fluid Properties

Parameter	Value
Reservoir Pressure	2299.2 psi
Reservoir Temperature	157 °F
Initial Water Saturation (Swi)	0.16
Porosity (ϕ)	0.20
Original Oil in Place (OOIP)	36.03 MMSTB
Gas Cap Ratio	0.03
Solution Gas–Oil Ratio (Rs)	426.1 scf/stb
Rock Compressibility	4.5×10^{-6} 1/psi
Oil Viscosity	5 cP
Water Viscosity at 157 °F	≈0.36 cP
Reservoir Salinity	25,000–35,000 ppm
Injected Polymer Salinity	2,000 ppm

Table A1: Summary of key reservoir and fluid properties used in CMG STARS simulation.

Simulation and Polymer Injection Parameters

Parameter	Value
Simulation Period	2025 – 2055
Injection Scheme	Polymer flooding after initial waterflooding
Polymer Concentration	2000 ppm HPAM
Injection Rate	500 stb/day
Polymer Slug Size	0.5 PV
Boundary Condition	No-flow (closed system)
Well Configuration	1 Injector – 1 Producer (five-spot pattern)

Grid System	Cartesian, 20×20×6
Cell Size	100 ft × 100 ft × layer thickness

Table A2: Input parameters and operating conditions for the polymer flooding simulation.

Calculated Parameters and Results

The results obtained from the simulation indicate improved reservoir pressure maintenance and higher oil recovery when polymer flooding was implemented. The pressure remained stable around 2100 psi throughout the simulation period, whereas the base case (without polymer) showed a steady pressure decline, reaching depletion by the year 2047.

Parameter	Calculated Value
Average Reservoir Pressure (Polymer Case)	≈2100 psi (stable)
Average Reservoir Pressure (Base Case)	Declined to 0 psi by 2047
Oil Recovery (Base Case)	≈36% OOIP
Oil Recovery (Polymer Case)	≈48% OOIP
Mobility Ratio (M = (k_rw/μ_w)/(k_ro/μ_o))	Improved to <1 due to increased water viscosity
Water Viscosity Used	0.36 cP
Polymer Solution Viscosity	≈15–20 cP