

**OPTIMIZATION OF WATER INJECTION STRATEGY FOR IMPROVED OIL  
RECOVERY IN FIELD IZYP IN NIGER DELTA**

**A PROJECT REPORT**

**SUBMITTED BY**

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**A PROJECT REPORT SUBMITTED AS A PARTIAL FULFILLMENT FOR THE  
AWARD OF THE DEGREE OF  
BACHELOR OF ENGINEERING  
IN  
PETROLEUM ENGINEERING  
FACULTY OF ENGINEERING  
UNIVERSITY OF BENIN  
BENIN CITY, EDO STATE**

**APRIL, 2024**

## CERTIFICATION

This is to certify that this project work was carried out by **OKAFOR CHUKWUEDOZIE ISRAEL** with matriculation number **ENG1805198**, of the Department of Petroleum Engineering, Faculty of Engineering, University of Benin, Benin City, Edo State, Nigeria.

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## ACKNOWLEDGEMENT

First and foremost, I would like to express my sincere gratitude to God Almighty, who has bestowed upon me wisdom and strength throughout my undergraduate years. Secondly, I extend my deepest appreciation to my supervisor, Dr. I. Ohenhen, whose unwavering support, guidance, and mentorship were instrumental throughout this research journey.

I am also immensely grateful to the Department of Petroleum Engineering at the University of Benin and the dedicated staff, where I had the privilege of conducting my research. The academic setting provided me with the essential resources, facilities, and intellectual stimulation required for the pursuit of knowledge and innovation.

I am also grateful to the Head of Department of the Department of Petroleum Engineering, Dr. S.A. Igbidere for his thoughtfulness in running the Petroleum Engineering Department where I did this research.

To my cherished family and friends, you have been my pillars of strength and endless sources of encouragement, for which I am profoundly thankful. Special appreciation goes to THE HILLS and Excellent boys for their support and encouragement.

I would also like to appreciate my lecturers who have tirelessly impacted knowledge, money could not buy, in me; Prof O.A Olafuyi, Prof K.I. Idigbe, Prof K.O. Bello, Dr. P.O Ogbeide, Dr. D.O. Onaiwu, Engr. E.W. Osagie, Engr. B. Otamere, Engr. Benedict. I am grateful.

Thank you all for your unwavering support and encouragement.

## **DEDICATION**

This project work is dedicated to God Almighty for His divine provision and care throughout my time at the University of Benin.

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## ABSTRACT

The IZYP field, located in the Niger Delta region, is an oil rim reservoir characterized by a combined drive mechanism involving both an aquifer and solution gas. The field has undergone primary recovery and conventional water injection, achieving a recovery factor of 19% and 28.5%, respectively. However, the late initiation of water injection led to substantial pressure depletion and solution gas liberation, compromising the reservoir's natural energy drive and hindering efficient hydrocarbon recovery. This study aimed to optimize the water injection strategy for the IZYP field to maximize oil recovery and resource utilization. A representative reservoir simulation model was developed through history matching, replicating the field's past production performance. Subsequent simulations evaluated the impact of modifying water injection timings and operational parameters on overall recovery factors. The optimized water injection strategy involved initiating water injection at an earlier stage (3,015 days or 1997), effectively maintaining reservoir pressure above the bubble point. This proactive approach minimized solution gas production and preserved the reservoir's energy potential. The optimized strategy yielded a substantial improvement in the ultimate recovery factor, increasing from 28.5% to 32.6% after 34 years of production. Comparative analyses of average reservoir pressure, gas-oil ratio (GOR), and recovery factor graphs illustrated the significant benefits of the optimized approach. Early water injection effectively mitigated GOR spikes, indicating reduced solution gas liberation and improved pressure maintenance. The optimization process identified the most favorable combination of water injection well locations and injection rates, tailored to the specific characteristics of the IZYP field. The findings underscore the importance of timely and strategic reservoir management practices, particularly in fields with combined drive mechanisms.

# **CHAPTER ONE**

## **INTRODUCTION**

### **1.1 BACKGROUND OF THE STUDY**

As the world transitions to cleaner energy sources, improving the efficiency and environmental impacts of existing oil recovery methods remains imperative in the near term to maintain crucial energy supply chains while new technologies scale up. Water flooding, the process of injecting water into oil reservoirs to increase pressure and oil flow to production wells, is a widely used technique for enhancing crude oil recovery. Optimizing water flooding processes presents opportunities to extract more oil from existing fields in a more sustainable manner, providing additional government funds to support the acceleration of renewable energy development and deployment at scale. Enhanced water flooding techniques today can serve as a bridge helping to responsibly supply societal energy needs as greener technologies continue ramping up worldwide.

Primary recovery methods rely solely on a reservoir's natural energy to produce hydrocarbons without any external intervention, yielding on average 34% of the initial oil volume as estimated by Sandrea and Sandrea (2007). As defined by Ahmed (2018), the primary recovery process depends on favorable reservoir rock properties, fluid characteristics, and geological structures to drive oil to the wellbore. However, reservoir pressures inevitably decline over time, reducing the natural drive mechanisms that enable commercial hydrocarbon flow rates. To combat diminishing reservoir energy and increase ultimate oil recovery, the industry developed enhanced oil recovery (EOR) methods that supply additional energy through external means. Implementing EOR techniques can boost output beyond primary production levels by mobilizing residual oil trapped

in the reservoir after initial natural pressure depletion. This study aims to evaluate an EOR approach with the goal of economically recovering further oil from mature fields to supplement declining conventional production.

Several EOR processes involve the injection of fluid (liquid or gas; or both) into the reservoir (Willhite and Society of Petroleum Engineers of AIME., 1986). These EOR operations aim to maximize crude oil recovery and a variety of approaches may be used depending on the reservoir's characteristics and stage of production at the time (Udy et al., 2017). The most widely used EOR method is water injection due to its ease of injection, low cost of implementation, and high displacement efficiency in comparison to other methods (Johns et al., 2000). Water injection stands as the most prevalent enhanced oil recovery technique used in the Niger Delta Basin fields. As early as 1890, operators noticed production increases when water entered productive zones (Willhite and Society of Petroleum Engineers of AIME., 1986). By 1907, water injection became an official practice following implementations in Pennsylvania's Bradford field. Depending on the water injection objectives, two primary categories exist - pressure maintenance injection and sweep efficiency improvement injection, known as waterflooding. As Onolemhemhen et al. (2017) discuss, injection into aquifers purely for reservoir repressurization constitutes water injection, while injection directly into oil-bearing zones to mobilize oil to producing wells defines the waterflooding variant.

## **1.2 PROBLEM STATEMENT**

The demand for oil has experienced a notable increase, with a growth rate of 2.9% in recent years according to BP (2019). However, the global oil production landscape continues to grapple with challenges such as declining rates and maturing fields. The imperative for implementing secondary

and tertiary recovery methods has consequently heightened. Despite this, enhanced oil recovery remains a perceived impracticality for numerous conventional fields, primarily attributed to its associated high costs and risks. Consequently, there is a growing emphasis on optimizing secondary recovery strategies within many companies, aiming to address the escalating demand for oil (Ivan, 2020).

In the primary production phase, as the reservoir undergoes extraction, the reservoir's energy diminishes progressively. A point is reached where the existing reservoir pressure becomes insufficient to ensure the smooth flow of fluids from the reservoir to the surface (Obibuike et al., 2022). At this juncture, it becomes economically prudent to employ the water injection technique for the recovery of residual hydrocarbons. This method concurrently elevates the reservoir pressure beyond the bubble point, ensuring that the reservoir pressure prevents the departure of solution gas from the crude oil.

### **1.3 AIM**

To optimize the water injection strategy for improved oil recovery in the IZYP field, Niger Delta.

### **1.4 OBJECTIVES**

The objectives of this study are stated below:

- To develop a representative reservoir simulation model for the IZYP field by performing history matching using historical production data.
- To evaluate the effectiveness of the existing water injection strategy in maintaining reservoir pressure and mitigating solution gas production.
- To investigate the impact of modifying the water injection initiation timing on overall oil recovery factors in the IZYP field.

- To optimize the water injection strategy by identifying the most favorable well locations and injection rates for maximizing hydrocarbon recovery.
- To assess the potential improvements in ultimate recovery factors achievable through the optimized water injection approach compared to the conventional strategy.
- To analyze the interplay between reservoir pressure management, solution gas behavior, and recovery efficiency in the IZYP field, which exhibits a combined drive mechanism involving aquifer and solution gas.
- To provide recommendations for field development strategies and reservoir management practices tailored to the specific characteristics of the IZYP field, ensuring optimal resource utilization and economic viability.

## **1.5 SCOPE OF RESEARCH**

This study aims to create a representative model for water injection in field IZYP in the Niger-Delta basin to make a general conclusion on how the secondary recovery process would affect the reservoir pressure and oil recovery in field IZYP.

## **1.6 RELEVANCE OF STUDY**

- To provide model the water injection process of field IZYP in the Niger-Delta basin.
- To acquire more knowledge in the field of research.

## **CHAPTER TWO LITERATURE REVIEW**

### **2.1 PRIMARY ENERGY RECOVERY**

The primary method for crude oil production relies on tapping into a reservoir's natural internal pressure to displace hydrocarbons to the surface. However, as described by Adeniyi et al. (2008), continuous primary recovery gradually depletes this reservoir energy over time as pressures decline. Once the natural drive mechanisms can no longer sustain commercial fluid flow rates, secondary recovery processes are employed per Imuokhuede et al. (2020). The main goals of augmenting the reservoir with secondary techniques are to boost incremental oil recovery and extend the economic life of the asset.

### **2.2 SECONDARY ENERGY RECOVERY**

When reservoir pressure depletion begins and primary recovery production significantly declines, secondary oil recovery methods are employed to improve oil production. The two fundamental methods used for secondary oil recovery are gas injection and water injection. Gas is injected into the primary or secondary gas caps, while water is injected into the production zone or water bearing zone (Radwan et al., 2021).

The selection of a suitable recovery scheme depends on a wide range of factors as highlighted by Nmegbu et al. (2017). These factors include:

- the geological characteristics of the reservoir,
- the residual oil saturation,
- the reservoir chemistry,

- the petrophysical properties,
- the lithology and,
- the expected ultimate recovery.

Secondary and enhanced oil recovery methods are specifically selected to address distinct recovery scenarios. For instance, reservoirs containing low API gravity crude oil may benefit from targeted thermal methods, while reservoirs characterized by high interfacial tension between the rock-fluid/oil-water system might warrant consideration of chemical processes. Additionally, enriched gas injection has shown promise in enhancing residual oil mobility through viscosity reduction. Thus, the selection of an optimal method is intricately tailored to the unique attributes and demands of each individual reservoir (Nmegbu et al., 2017).

### **2.2.1 VOIDAGE REPLACEMENT**

In the context of reservoir management, voidage replacement involves restoring the volume of extracted oil, gas, and water in the reservoir through fluid injection. The voidage replacement ratio, as outlined by Kim et al. (2019), quantifies this process by representing the ratio of injected fluid barrels to produced fluid barrels. This metric offers valuable insights into the efficacy of fluid injection for maintaining reservoir pressure and facilitating hydrocarbon recovery. In essence, vigilant monitoring and optimization of the voidage replacement ratio empower reservoir engineers to make informed choices about injection rates and volumes, thereby ensuring sustainable reservoir performance and optimizing hydrocarbon recovery.

## **2.2.2 WATER INJECTION**

Introducing water into oil reservoirs can help displace additional oil through improved flow patterns and pushing oil towards production wells. Waterflooding has proven an effective secondary recovery technique by enhancing field recovery factors, thanks largely to its capacity to improve macroscopic oil displacement and maintain reservoir pressure over time (Aghaeifar et al., 2018). Notably, waterflooding performance improves in heterogeneous reservoirs exhibiting water-wet rock where spontaneous water imbibition into matrix pores occurs readily. Saturated oil reservoirs also favor water as the injection fluid (Imuokhuede et al., 2020). However, sufficient water permeability remains crucial for efficiency in such reservoirs, as higher mobility facilitates optimal fluid flow to displace oil (Imuokhuede et al., 2020). Consequently, waterflooding presents an advantageous oil recovery method for heterogeneous, water-wet reservoirs with saturated oil, provided permeabilities allow adequate water mobility for oil displacement.

The utilization of intelligent well systems has significantly expanded the possibilities for manipulating and governing the pathways of fluid flow within oil reservoirs. With the ability to exert a certain degree of influence over the progression of the oil-water interface, there arises an opportunity to explore strategies for control that aim to achieve the utmost maximization of oil recovery (Van Essen et al., 2006). Through the application of intelligent well technology, reservoir engineers gain the capacity to strategically oversee fluid flow patterns, thereby optimizing displacement efficiency and sweep efficiency. These advancements in well technology hold substantial potential for facilitating the formulation and execution of effective control strategies, which can make a substantial contribution to the overall improvement of oil recovery from reservoirs.

### **2.2.2.1 DESIGNING A WATERFLOOD PROJECT**

In the early phases of evaluating the viability of a flood-based recovery approach, initial engineering assessment methods are utilized to determine whether the reservoir satisfies the minimum technical and economic requirements for a successful implementation. Should the assessment produce favorable outcomes, it becomes imperative to conduct more extensive technical computations, incorporating a diverse array of engineering and geoscientific investigations. A crucial component of these studies entails geologists working towards establishing a thorough comprehension of the internal attributes of the pay intervals, along with the continuity of non-pay intervals within the reservoir (Aristov et al., 2015).

A profound understanding of these aspects is essential in formulating an effective waterflood-based recovery strategy, ensuring optimal reservoir performance, and maximizing the ultimate recovery of hydrocarbons. Furthermore, the choice of an appropriate flood pattern style and well spacing holds significant importance. The primary goal of flood pattern analysis is to pinpoint suitable injection patterns that facilitate maximum contact between the injected water and the remaining residual oil in the reservoir. At this project stage, injectors can be established either by converting existing producing wells into injectors or by drilling additional infill injection wells (Ahmed, 2018; Sayyafzadeh et al., 2010). These decisions hinge on a comprehensive understanding of reservoir geology, surface facility design considerations (specifically water-injection volumes), and any constraints associated with the number of injectors and producers (Palsson et al., 2003).

Callaway (1959) developed an equation that provides a means to evaluate the success of the water flooding design in terms of its ability to enhance the recovery of hydrocarbons from the reservoir.

$$N_{pwf} = V_p \frac{1 - S_{wc}}{B_{oi}} \cdot \left\{ 1 - R_p - \frac{B_{oi}}{B_{oi}}, (1 - E_{vo} \cdot E_D) \right\}$$

Where;

$V_p$  = Floodable reservoir pore volume ( $7758 Ah\Phi$ ), barrels

$B_{oi}$  = Original formation volume factor, RB/STB

$B_{of}$  = Formation volume factor during water-flooding, RB/STB

$S_{wc}$  = Connate water saturation, fraction

$S_{or}$  = Residual oil saturation after water flooding,

fraction

$R_p$  = Primary recovery efficiency, fraction of Original Oil in Place (OOIP)

$E_{vo}$  = Overall volumetric sweep efficiency, fraction of reservoir volume

$E_D$  = Maximum unit displacement efficiency (to be defined later), fraction

$N_{pwf}$  = Water flood reserves, STB

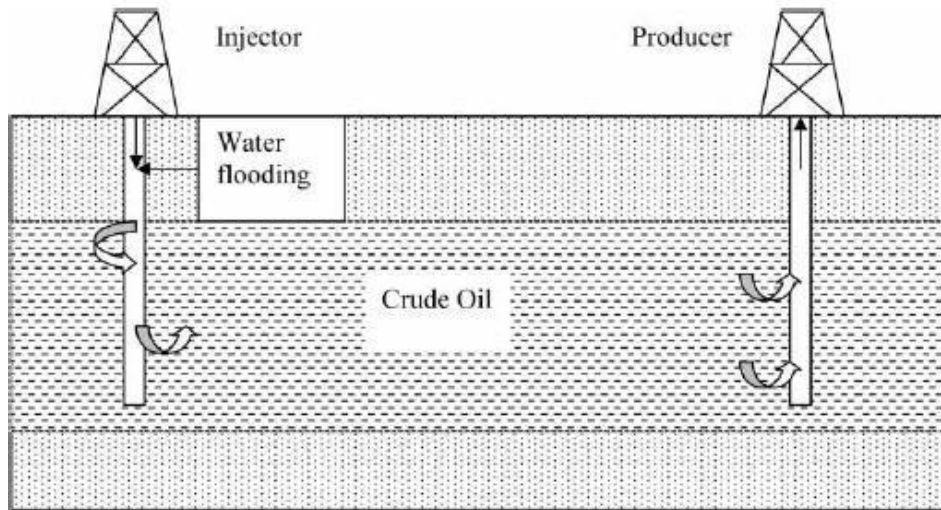


Figure 2. 1 Waterflooding Process (Adeniyi et al., 2008)

### 2.2.2.2 SUITABLE RESERVOIRS FOR WATERFLOODING

Water-drive reservoirs, where the primary facilitator of oil production is the expansion of water, are typically not deemed suitable candidates for water flooding—a technique involving the injection of water into the reservoir (Willhite and Society of Petroleum Engineers of AIME., 1986). This is mainly attributed to the existence of natural ongoing water influx. Nevertheless, under specific circumstances, it might prove advantageous to complement a natural water drive with water injection. This strategy can bolster a higher withdrawal rate, enhance the distribution of injected water across various areas of the field, encourage more uniform areal drainage, and facilitate improved voidage balance and influx volumes.

On the flip side, reservoirs driven by solution gas mechanisms are regarded as the most promising candidates for water flooding (Ahmed, 2018; Willhite and Society of Petroleum Engineers of

AIME., 1986). These reservoirs typically demonstrate low primary recovery rates, presenting a significant opportunity for additional oil recovery through water injection. The introduction of water can efficiently displace the remaining oil, resulting in a substantial increase in overall recovery.

### **2.2.2.3 FUNDAMENTAL PRINCIPLES GUIDING INTERACTIONS BETWEEN ROCKS AND FLUID.**

#### **2.2.2.3.1 WETTABILITY**

In the context of a rock/oil/brine system, wettability denotes the tendency of a fluid to selectively adhere to or spread across the surface of a rock in the presence of other immiscible fluids. In the waterflooding process, either oil or water can function as the wetting phase. When water occupies the smaller pores and makes contact with the larger pores, the rock is deemed water-wet. In this situation, the oil typically occupies the larger pores. Conversely, in an oil-wet condition, the oil is situated in the smaller pores while establishing contact with the larger pores that are filled with water (Zhang et al., 2015).

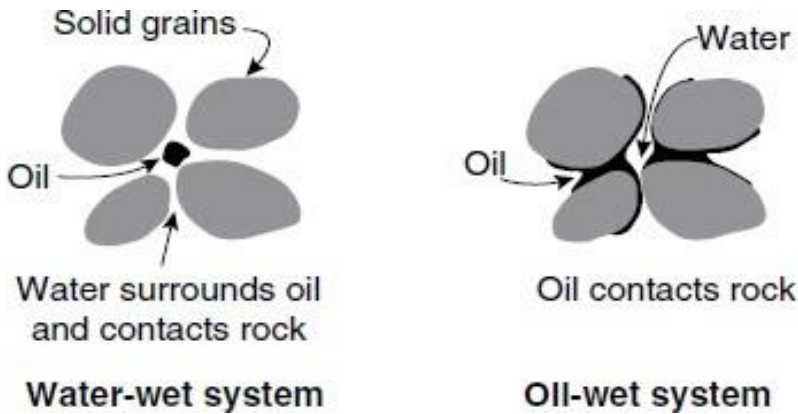


Figure 2. 2 Effect of Wettability on Saturation (Green and Willhite, 2018)

Water-wet reservoirs display a favorable inclination towards primary recovery and waterflooding methods. Conversely, in oil-wet reservoirs, the adhesive forces between the rock surface and the oil hinder oil movement, resulting in higher residual oil saturation and consequently lower oil recovery. In specific reservoir systems, the rock does not exhibit a distinct preference for either fluid, whether it be oil or water. This distinctive condition, termed intermediate or neutral wettability, signifies an equal affinity of the rock towards both fluids (Alvarado and Manrique, 2010; Tiab and Donaldson, 2015).

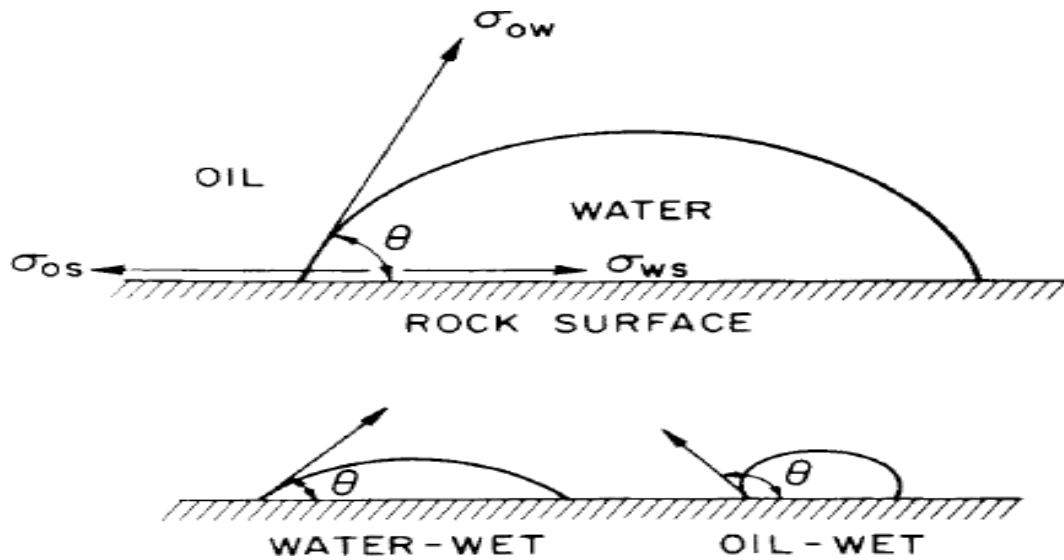


Figure 2. 3 Wettability of Oil/Water/Rock System (Willhite and Society of Petroleum Engineers of AIME., 1986)

### 2.2.2.3.2 CAPILARY PRESSURE

Capillary pressure is a crucial factor in the complex dynamics of petroleum reservoirs, involving the pressure difference between two immiscible fluids at their interface due to the varying densities of these fluids. In the context of petroleum reservoirs, capillary forces result from a combination of factors, including the interplay between surface and interfacial tensions inherent in both the rock matrix and the fluids within the reservoir, the geometric characteristics and dimensions of the pore network, and the wettability characteristics governing the system (Ahmed, 2018).

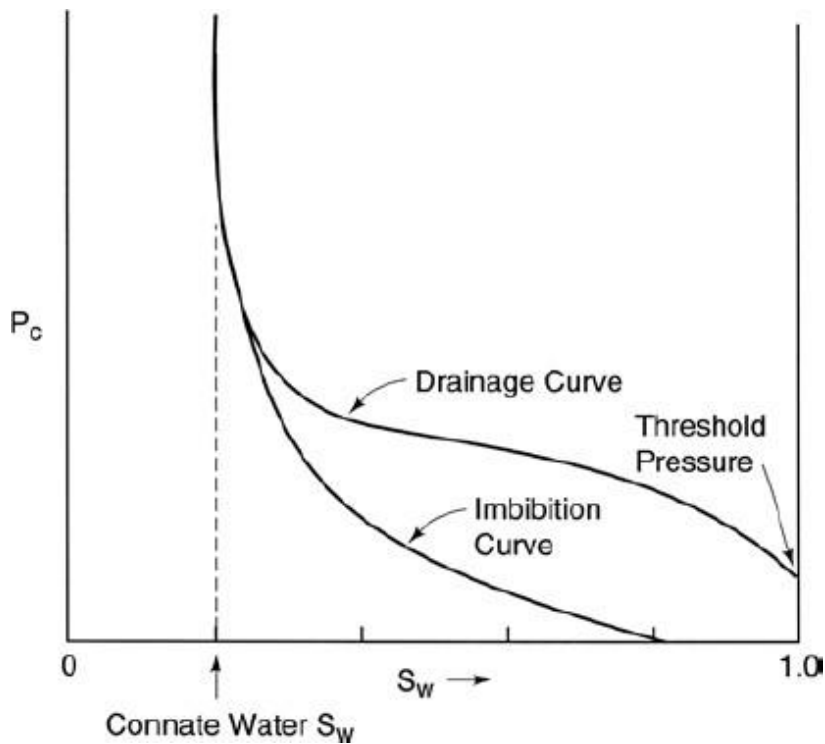


Figure 2. 4 Capillary Curve for a water-wet Reservoir (Green and Willhite, 2018)

A critical factor influencing capillary pressure is the interfacial tension between immiscible fluids. It has been observed that an increase in interfacial tension corresponds to an increase in capillary pressure. This connection underscores the importance of interfacial tension in determining the magnitude of capillary pressure within a given system. Moreover, the relationship between capillary pressure and pore size is found to be inversely proportional. In other words, as pore size decreases, capillary pressure escalates. This discovery emphasizes the crucial role of pore size in dictating the magnitude of capillary pressure within a reservoir. The heightened capillary pressures associated with smaller pore sizes contribute to an increase in the overall capillary resistance faced by fluids attempting to flow through the reservoir. Consequently, less permeable reservoirs, characterized by smaller pore sizes, inherently exhibit higher capillary pressures. This insight

establishes a fundamental link between reservoir permeability and capillary pressure, highlighting the substantial impact of reservoir characteristics on the behavior and fluid flow dynamics within the system (Tiab and Donaldson, 2015).

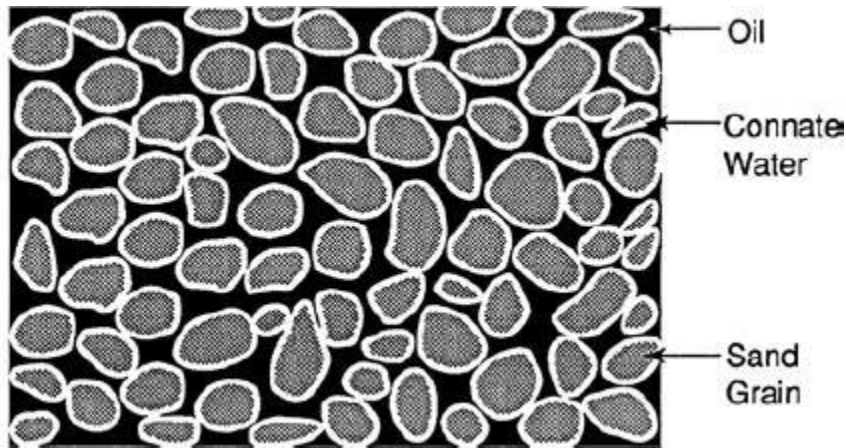


Figure 2. 5 Oil and Water Between Grains of Rock (Green and Willhite, 2018)

### **2.2.2.3.3 RELATIVE PERMEABILITY**

Relative permeability plays a pivotal role in understanding the flow dynamics of multiple fluids within a reservoir, especially when one fluid moves through the reservoir alongside other immiscible fluids. The reservoir's ability to transmit each individual fluid is inherently affected by the unique properties of the fluids involved. As such, relative permeability becomes a crucial parameter in quantifying the varying capacity of the reservoir to transport different fluids (Obibuike et al., 2022).

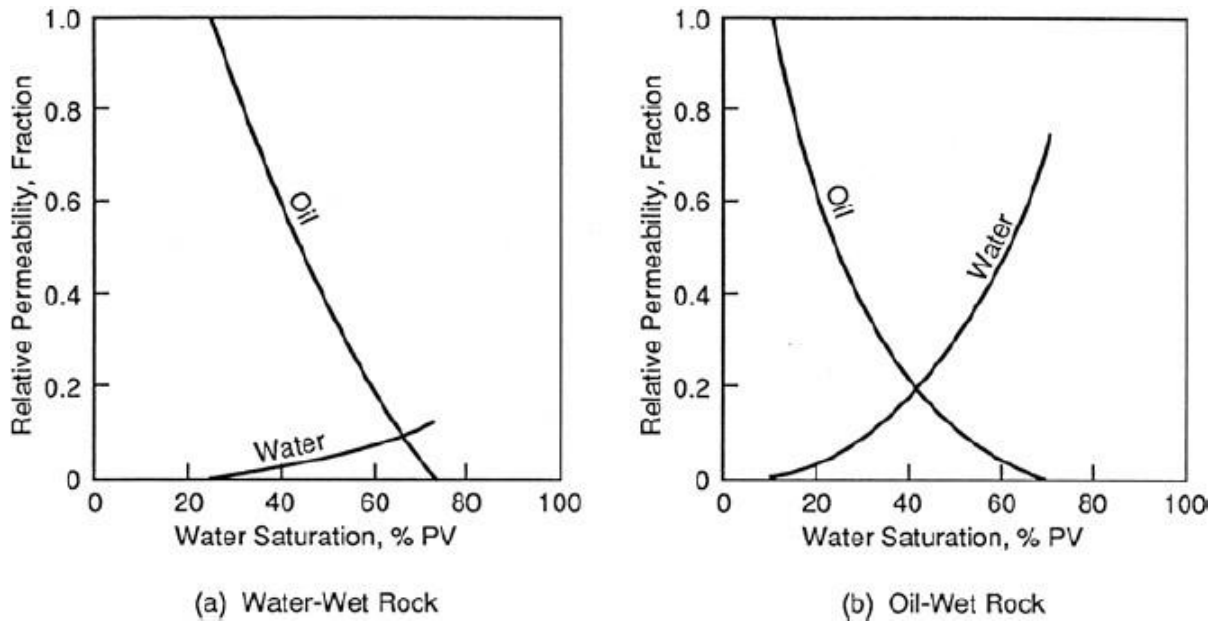


Figure 2. 6 Wettability Effect on Relative Permeability Curves (Green and Willhite, 2018)

Relative permeability for a specific fluid is characterized as the ratio of its effective permeability to a reference permeability, termed the base permeability. Commonly, the base permeability is represented by either the absolute permeability of the porous medium or the permeability of air. Through this ratio, relative permeability offers insights into the relative transmissibility of different fluids when they coexist and move simultaneously within the reservoir (Almutairi et al., 2007).

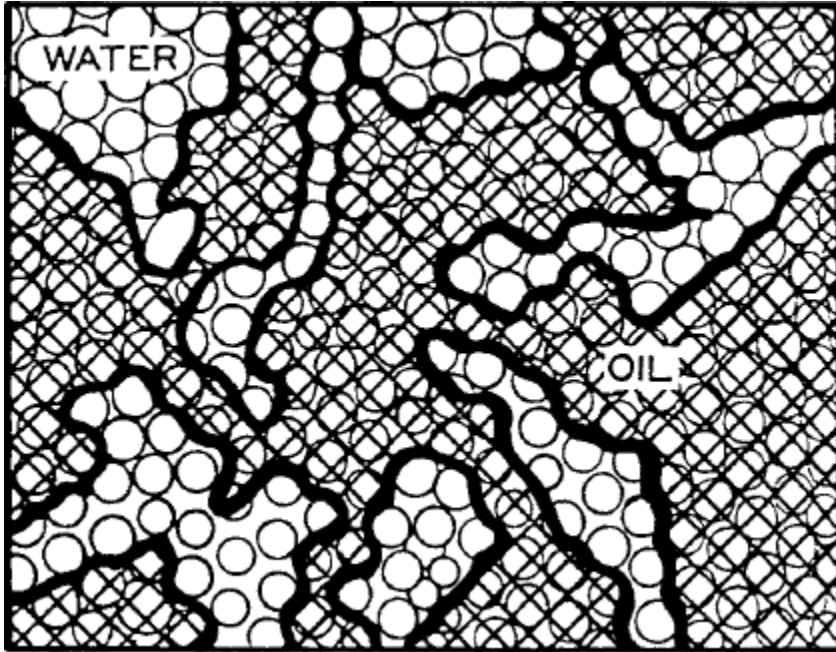


Figure 2. 7 Flow Channel Boundaries from a Simultaneous Flow of Oil and Water (Willhite and Society of Petroleum Engineers of AIME., 1986)

#### **2.2.2.3.4 MOBILITY RATIO**

The concept of relative permeability is manifested in the ratio of the effective permeability of a fluid to its viscosity. Notably, oil typically exhibits higher viscosity compared to water. Consequently, when the effective permeability remains constant, water tends to demonstrate greater mobility than oil, resulting in a phenomenon where water outpaces the movement of oil. This difference in mobility between the two fluids holds significant implications for calculating flooding performance within the reservoir. The mobility ratio plays a critical role in evaluating the efficiency of displacement processes, defined as the ratio of the mobility exhibited by the displacing phase to that of the displaced phase (Obibuike et al., 2022).

A mobility ratio equal to or less than 1 is highly desirable and actively pursued in reservoir engineering practices. This condition indicates that the mobility of oil is either equivalent to or greater than that of water, leading to enhanced oil recovery prospects. Conversely, a mobility ratio exceeding 1 is considered unfavorable due to the increased mobility of water relative to oil (Mai and Kantzas, 2008). Such a situation presents significant challenges in reservoir management, often resulting in undesirable phenomena such as viscous fingering and early water breakthrough.

#### **2.2.2.3.5 VISCIOUS FINGERING**

Viscous fingering is a consequence of inherent differences in fluid mobilities, primarily driven by variations in fluid viscosities. When the displacing fluid, such as water, displays higher mobility than the oil phase, it leads to an irregular and erratic advancement of water. This progression overrides the oil phase in an unpredictable manner as it moves toward the producing well. This disruptive process, exacerbated by the reservoir's permeability heterogeneity, results in significant oil entrapment, hindering its recovery potential. Viscous fingering leads to poor recovery efficiencies, primarily due to early breakthroughs of the displacing phase (Tewari et al., 2005). The occurrence of viscous fingering has substantial implications for reservoir management strategies, challenging the attainment of optimal oil recovery. The irregular advancement of the displacing phase disrupts the uniform sweep of the reservoir, leaving significant pockets of oil isolated and unrecovered.

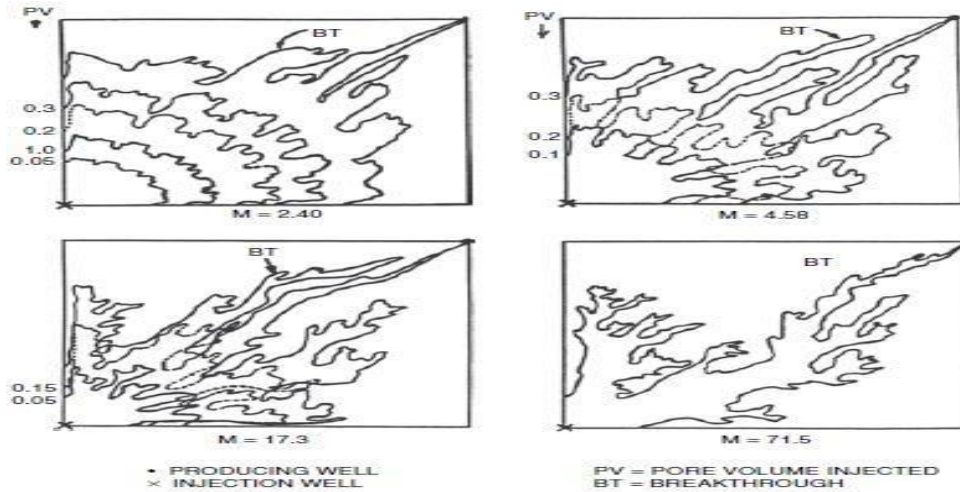


Figure 2. 8 Viscous Fingering (Green and Willhite, 2018)

### 2.2.2.3.6 RECOVERY EFFICIENCY

The assessment of recovery efficiency in enhanced oil recovery (EOR) processes holds paramount importance, given its pivotal role in evaluating the economic viability of flooding techniques. This metric significantly influences investment decisions, guides strategic planning, and determines the appropriateness of specific EOR methods for given field and reservoir conditions (Salufu et al., 2020). The quantification of recovery efficiency carries substantial implications for the overall profitability and success of water injection operations.

In the realm of oil recovery analysis, the efficiency concept can be scrutinized from both microscopic and macroscopic perspectives. Microscopically, the efficiency of fluid displacement is commonly known as displacement efficiency, while macroscopically, it is often termed volumetric or sweep efficiency. The combination of these two efficiency components yields the overall oil recovery efficiency (Denovan Abili et al., 2021).

Considering both microscopic and macroscopic efficiency components provides a comprehensive framework for analyzing and quantifying the efficiency of oil recovery processes. These efficiency metrics play a crucial role in assessing the performance of various recovery techniques, optimizing operational strategies, and enhancing the overall efficiency of oil production from reservoirs.

#### **2.2.2.4 FACTORS THAT AFFECT WATERFLOODING PROCESS**

The successful implementation of waterflood design requires a deliberate focus on reservoir regions with limited oil production during primary recovery. These areas typically encompass tight hydrocarbon-bearing zones, fault-induced compartments, and untapped reservoir sections. To gain an in-depth understanding of residual oil distribution, a comprehensive reservoir description and characterization are imperative (Imuokhuede et al., 2020). Several factors influence waterflooding.

##### **2.2.2.4.1 RESIDUAL OIL SATURATION**

Residual oil saturation (ROS) represents the portion of oil saturation that remains within a reservoir after the extraction achieved through conventional recovery methods, including waterflooding. Quantifying and understanding the distribution of residual oil within a reservoir have significant implications for determining the economic feasibility of implementing Enhanced Oil Recovery (EOR) techniques for reservoir exploitation. ROS variation can arise from inherent heterogeneities in the rock formation or as a consequence of recovery processes like waterflooding. Several techniques are available for measuring ROS; however, it is essential to note that these methods may yield disparate results. Therefore, comprehending the limitations, accuracies, and potential sources of error associated with different ROS measurement techniques is of paramount

importance when selecting the most appropriate approach for accurately quantifying ROS within a reservoir (Chang et al., 1988).

#### **2.2.2.4.2 RESERVOIR HETEROGENEITY**

In a reservoir characterized by a relatively uniform formation, the waterflood process is expected to thrive, aligning closely with the projected outcomes derived from flood analysis. However, a notable obstacle in waterflood projects lies in mitigating the substantial bypassing of in-situ oil. The presence of high-permeability channels, undetected interlayer crossflow, fractures, compartments formed by fault sealing, zones with low transmissibility, and other forms of heterogeneity can detrimentally impact the effectiveness of waterflood initiatives. To enhance the recovery processes in both homogeneous and heterogeneous formations, the implementation of a close well spacing strategy proves advantageous (Imuokhuede et al., 2020). This approach facilitates the extraction of additional oil reserves by ensuring a comprehensive and efficient coverage of the reservoir.

#### **2.2.2.4.3 OIL GRAVITY AND VISCOSITY**

The difference in viscosity between water and heavy oil presents a challenge in achieving efficient displacement of heavy oil through water injection. Consequently, successful waterflooding projects are often associated with reservoirs characterized by relatively low viscosities, typically below 30 centipoise (cp), and high oil gravities exceeding 22°API (Imuokhuede et al., 2020).

This combination of favorable reservoir properties enables enhanced mobility of the injected water, facilitating more effective displacement of heavy oil.

#### **2.2.2.4.4 EFFECT OF AQUIFER**

Waterflood projects have shown success in reservoirs characterized by a limited water influx. However, reservoirs experiencing a strong influx of water may not be ideal candidates for waterflooding, as the natural displacement of oil by water already taking place may limit the marginal benefits achieved through additional water injection (Imuokhuede et al., 2020). In such cases, the inherent dynamics of the reservoir's water-oil displacement may render waterflooding less effective in significantly enhancing oil recovery.

#### **2.2.2.4.5 COMPATIBILITY OF INJECTED WATER**

Injectivity issues can emerge when the injected water is not compatible with the native reservoir water. In such cases, there is a substantial risk of potential formation damage occurring (Imuokhuede et al., 2020). Compatibility between the injected water and the reservoir water is vital to ensure the smooth functioning of waterflooding operations.

#### **2.2.2.4.6 COST**

A comprehensive evaluation of the final cost associated with a waterflood project is crucial. It is imperative to conduct a thorough assessment of the potential profits to determine the feasibility and success of the project. By examining the economic viability of the project, one can ascertain whether the expected returns and financial benefits justify the investment (Imuokhuede et al., 2020). Considering the final cost and conducting a profitability analysis are essential steps in evaluating the overall viability and potential success of a waterflood project.

#### **2.2.2.4.7 INJECTED PRESSURE**

The response time of the producer in a waterflood project is influenced by the injection rate, and this, in turn, impacts the net present value of the asset. Ensuring that preferential flow paths for water channeling are avoided requires maintaining a fracture pressure higher than the injection pressure. Consequently, injectivity restrictions are commonly encountered in reservoirs with shallow depths or in reservoirs with constrictions. In numerous cases, the limitations in injection pressure and rate result in suboptimal oil recovery, thereby hindering the achievement of maximum recovery potential (Imuokhuede et al., 2020). Recognizing and addressing these injectivity challenges are essential considerations in the design and implementation of waterflood strategies to enhance the overall economic viability and success of the reservoir asset.

## **CHAPTER THREE**

### **RESEARCH METHODOLOGY**

#### **3.1 RESERVOIR DESCRIPTION**

This study was conducted in the Niger Delta Field IZYP, where the primary reservoir of interest is an oil rim reservoir comprised of Late Cretaceous turbidite sandstone. The reservoir exhibits a combined drive mechanism, involving both an aquifer and solution gas. The reservoir has a thickness of 30 feet and is represented by a grid model with 30 cells in the x-direction, 27 cells in the y-direction, and 1 cell in the z-direction. Initially, primary recovery methods were employed to extract hydrocarbons from the reservoir. Well IZY01, the sole producer at the time, was able to recover 19% of the Original Oil in Place (OOIP) during its production period from January 31, 1990, to November 30, 2000. However, declining reservoir pressure necessitated the implementation of secondary recovery techniques.

In response to this challenge, well IZY03 was drilled on December 31, 2000, as the first water injection well for the field. Subsequently, an additional production well, IZY02, was drilled on March 31, 2009, to supplement hydrocarbon recovery efforts. The layout of the reservoir, including the well locations, is depicted in Figure 3.1.

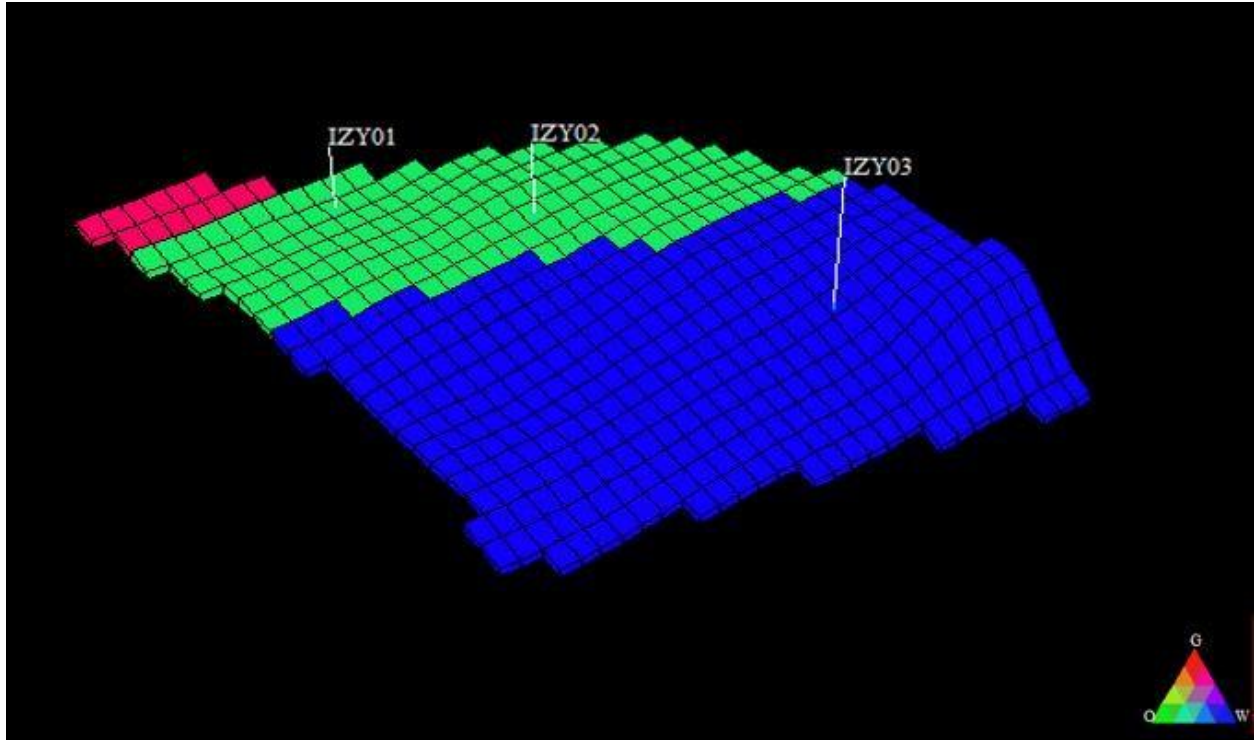


Figure 3. 1 Layout of Field IZYP

### 3.2 RESERVOIR AND FLUID PROPERTIES

The reservoir properties for the IZYP field are summarized in Table 3.1. The initial reservoir pressure and temperature were 2670 psi and 161°F, respectively. The Original Oil in Place (OOIP) was estimated to be 32 MMSTB, and the average porosity of the reservoir was 0.29.

The fluid properties, commonly referred to as PVT (pressure-volume-temperature) properties, were determined using established PVT correlations. The resulting PVT data, presented in Table 3.2, provide a comprehensive representation of the black-oil fluid properties under various conditions, ranging from below to above the bubble point pressure.

Table 3. 1 Reservoir Data

<b>Reservoir Data</b>		
Reservoir Thickness	30	ft
OOIP	32	MMSTB
X Y Z	123 x 62 x 51	
Initial Reservoir Pressure	2670	psi
Temperature	161	deg F
bubble point	2530	psi
oil FVF	1.3	rb/stb
NTG	0.98	
API gravity	35	
Porosity	0.29	
Permeability	700	mD
Oil compressibility factor	1.30E-06	

This table assumes the presence of an unlimited supply of free gas, enabling the simulation software to accurately manage any excess gas that may arise during the production process and of particular significance is the row in Table 3.2 corresponding to a pressure of 2530 psi, as this pressure represents the reservoir's bubble point. At pressures below this value, the oil phase is expected to be saturated with dissolved gas, necessitating the consideration of solution gas drive mechanisms during the simulation and analysis processes.

Table 3. 2 PVT Table

P	Bo	Bg	Rs	Vo	Vg
(psi)	(rb/stb)	(rb/mcf)	(Mcf/stb)	(cp)	(cp)
14.7000	1.0560	211.6741	0.0012	2.5415	0.0127
200.0000	1.0678	15.2603	0.0259	2.1669	0.0129
400.0000	1.0834	7.4749	0.0589	1.8273	0.0131
750.0000	1.1144	3.8516	0.1243	1.4212	0.0135
1200.0000	1.1584	2.3149	0.2171	1.1063	0.0144
2000.0000	1.2441	1.3302	0.3982	0.8028	0.0165
2530.0000	1.3048	1.0469	0.5263	0.6844	0.0182
3000.0000	1.3607	0.8927	0.6443	0.6078	0.0198
3471.0000	1.4184	0.7887	0.7661	0.5481	0.0215
4000.0000	1.4850	0.7078	0.9066	0.4953	0.0233
5000.0000	1.6152	0.6114	1.1815	0.4216	0.0265
6000.0000	1.7505	0.5533	1.4670	0.3694	0.0295
7000.0000	1.8900	0.5144	1.7616	0.3303	0.0322
8000.0000	2.0334	0.4864	2.0641	0.2998	0.0346

### 3.3 HISTORY MATCHING

History matching is the process of adjusting input parameters in a reservoir simulation model to align simulated results with observed production data, such as flow rates, pressures, and

temperatures. The premise is that if a model can accurately replicate past performance, it may be useful for forecasting future behavior under various operational scenarios (Abdulrazzaq and Hasan, 2023). The calibration process involves multiple iterations, where simulation outcomes are analyzed, compared against field data, and input parameters are adjusted to improve the match.

For the IZYP field, history matching was facilitated by setting up quarterly calculations of cumulative production for each well, assuming January 1, 1990, as the reference time (t=0). This approach enabled effective replication of the historical production rates observed in the field. By iteratively adjusting uncertain parameters within the simulation model and comparing the results against the quarterly cumulative production data, a satisfactory match was achieved, increasing confidence in the model's ability to forecast future performance reliably. Table 3.3 displays the production data for each well at the beginning of their active production periods, which served as the initial conditions for the history matching process.

Table 3. 3 History Matching Data

IZY01	RVBPROD	RATE	0	BHP	14.7
IZY02	RVBPROD	RATE	0	BHP	14.7
IZY03	WATINJ	RATE	0	BHP	4500
TIME 93	years	0.3			
IZY01	RVBPROD	RATE	1940.9	BHP	14.7
IZY02	RVBPROD	RATE	0	BHP	14.7
IZY03	WATINJ	RATE	65.8	BHP	4500
TIME 4111	years	11.3			
IZY01	RVBPROD	RATE	764.4	BHP	14.7
IZY02	RVBPROD	RATE	1005	BHP	14.7
IZY03	WATINJ	RATE	5199	BHP	4500
TIME 7215	years	19.8			

### **3.4 OPTIMIZATION OF THE WATER INJECTION PROCESS**

After successfully reproducing the reservoir behavior through history matching, efforts were made to investigate potential improvements to the existing water injection strategy employed in the IZYP field. The primary objective was to determine whether the recovery factors obtained from the initial water injection process could be enhanced through either modifying the well locations or adjusting the injection rates.

The optimization process involved running multiple simulation scenarios, systematically varying the input parameters related to the water injection wells. These parameters included the well locations within the reservoir grid and the water injection rates over time. Each scenario was meticulously evaluated, and the resulting oil recovery factors were compared against the base case representing the current injection strategy.

By analyzing the outcomes of these simulation runs, the most favorable combination of well locations and injection rates could be identified, leading to an optimized water injection strategy. This optimized approach aimed to maximize oil recovery while considering practical constraints and operational limitations, such as maximum injection pressures and available surface facilities. The optimization workflow not only provided valuable insights into the potential improvements achievable through strategic water injection management but also highlighted the intricate interplay between various reservoir parameters and their impact on overall recovery efficiency.

## **CHAPTER FOUR**

### **RESULTS AND DISCUSSION**

#### **4.1 RESULTS**

The following results were obtained at the end of the simulation for the already existing water injection and the optimized case.

##### **4.1.1 SIMULATION RESULTS FROM THE WATER INJECTION CASE**

Figure 4.1 illustrates the evolution of the average reservoir pressure over time, spanning from 1990 to 2024 (112,357 days). Prior to the implementation of water injection on December 31, 2000 (4,111 days), as depicted in figure 4.2, the graph of HDPVI (water) against time, the average reservoir pressure declined below the bubble point pressure of 2,530 psi, reaching 1,736 psi at the time of initiating the water injection process. This pressure depletion below the bubble point resulted in the liberation of solution gas from the oil phase, as evidenced by the increase in the gas-oil ratio (GOR) observed during this period in figure 4.3. The release of dissolved gas led to a reduction in the reservoir's natural energy drive, negatively impacting the overall recovery efficiency.

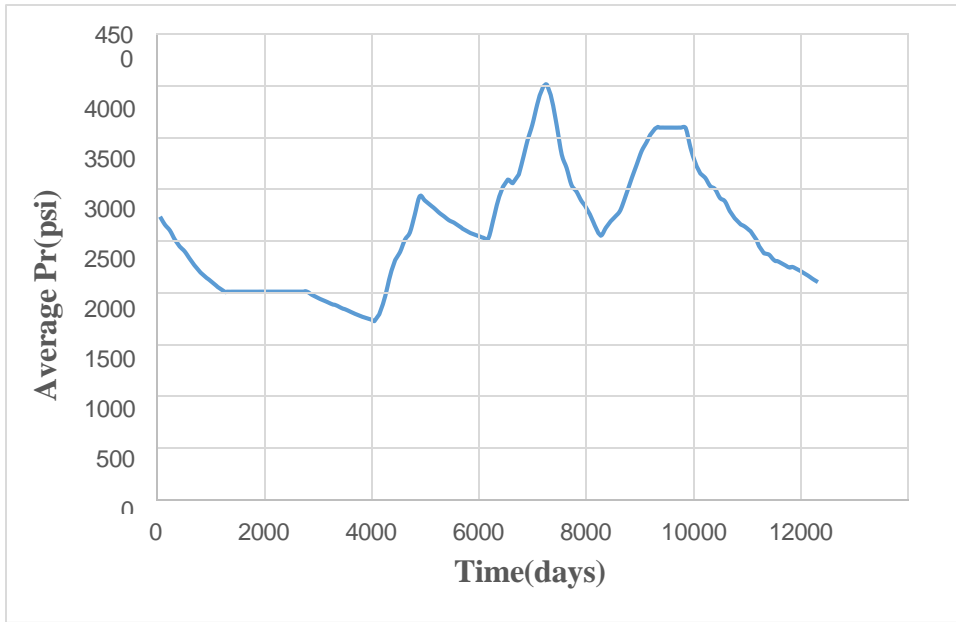


Figure 4. 1 Graph of Average Reservoir Pressure Against Time

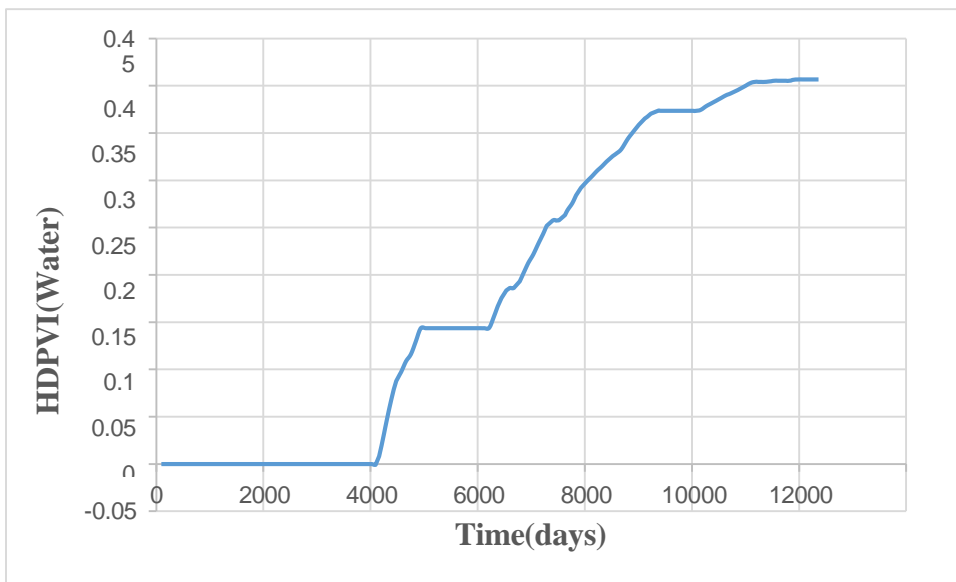


Figure 4. 2 Graph of HDPVI (Water) Against Time

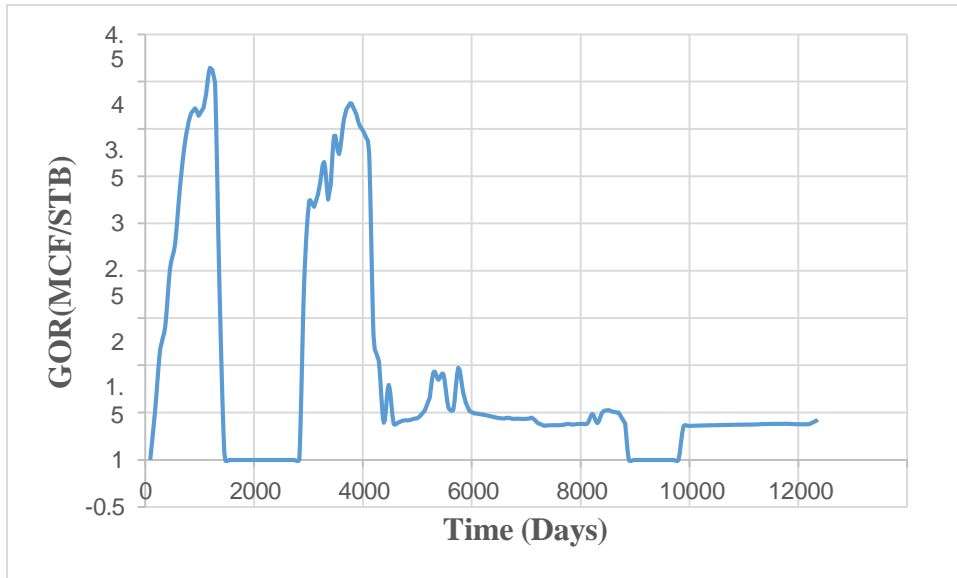


Figure 4. 3 Graph of GOR Against Time

The introduction of water injection aimed to supplement the declining reservoir pressure and maintain it above the bubble point, thereby mitigating further loss of solution gas and preserving the reservoir's energy. As illustrated in figure 4.4, the ultimate recovery achieved through the implemented water injection technique after 34 years was 28.5%.

It is important to note that the water injection strategy was designed to optimize oil recovery by managing the reservoir pressure and maintaining it within the desired range. However, the simulation results suggest that further improvements in recovery factors may be achievable through optimization of the injection rates and well locations, as discussed in the subsequent sections.

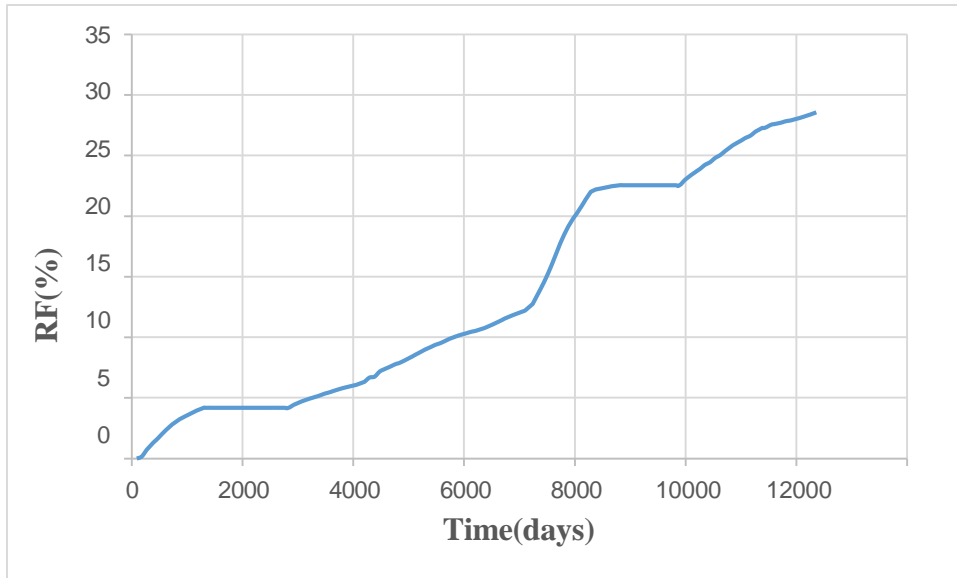


Figure 4. 4 Graph of Recovery Factor Against Time

#### **4.1.2 SIMULATION RESULTS FROM THE OPTIMIZED WATER INJECTION CASE**

Building upon the insights gained from the conventional water injection strategy, further optimization efforts were undertaken to enhance the overall recovery performance. A key modification involved initiating the water injection process earlier, at 3,015 days (1997), as depicted in figure 4.5, the HDPVI (water) graph. This proactive approach to water injection resulted in a notable improvement in the ultimate recovery factor, which increased from 28.5% in the first case to 32.6% after 112,357 days (approximately 34 years) as shown in figure 4.6. The early implementation of water injection effectively addressed the issue of excessive solution gas production observed during the primary recovery phase, as evidenced by the GOR (gas-oil ratio) and average reservoir pressure graphs in figure 4.7 and figure 4.8, respectively.

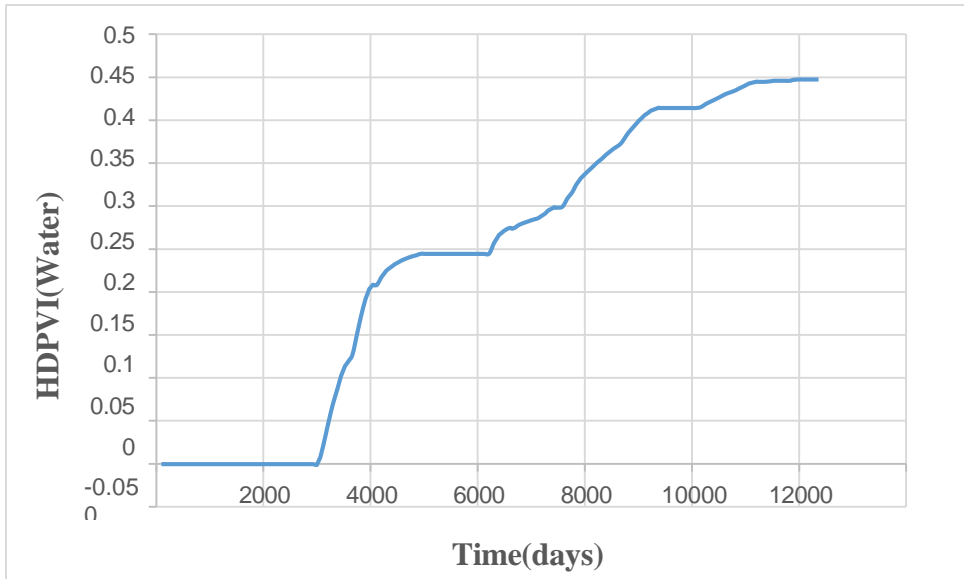


Figure 4. 5 HDPVI(Water) against Time during the Optimized Water Injection

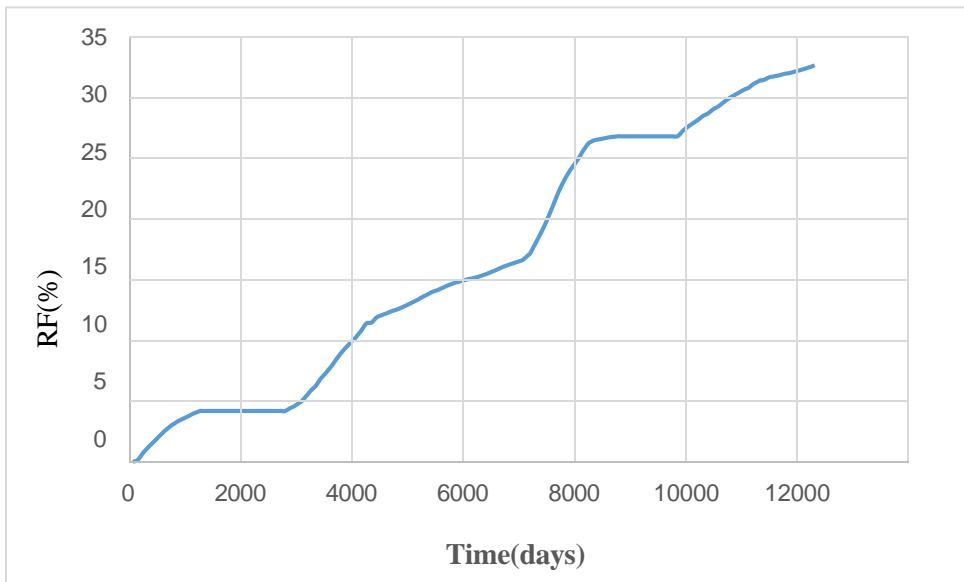


Figure 4. 6 Recovery Factor Against Time in the Modified Water Injection Case

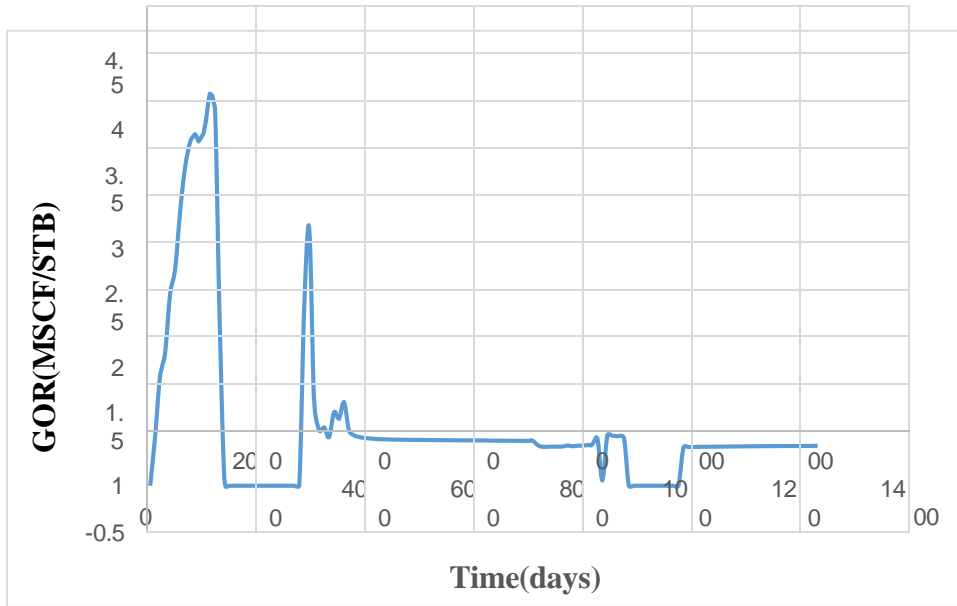


Figure 4. 7 GOR Against Time during Optimized Water Injection

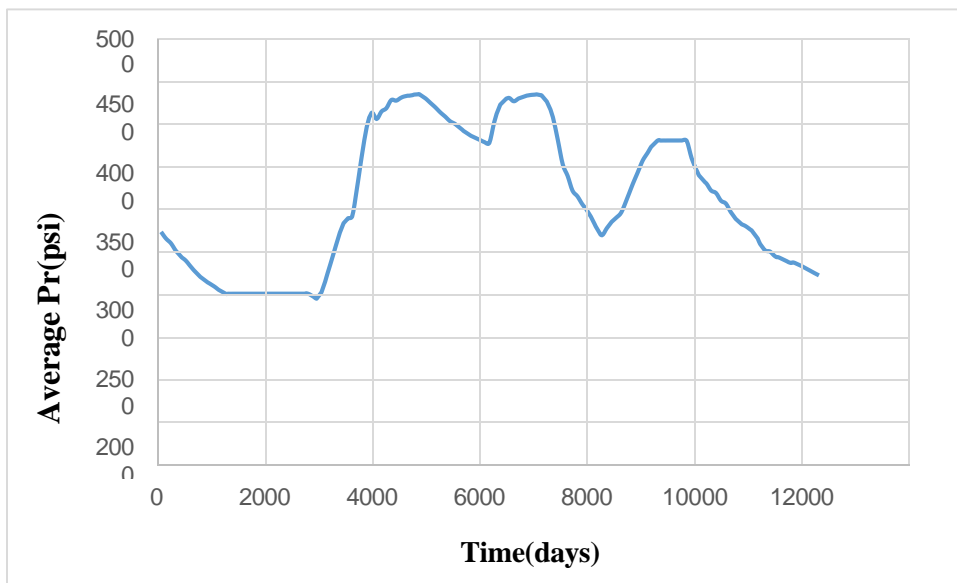


Figure 4. 8 Average Reservoir Pressure Against Time during the Optimized Water Injection Case

During the primary recovery period, the reservoir experienced substantial depletion, leading to the liberation of dissolved gas from the crude oil. This phenomenon, characterized by a sharp increase in the GOR, compromised the reservoir's natural energy drive and hindered efficient hydrocarbon recovery. By introducing water injection earlier, the reservoir pressure was maintained above the bubble point, mitigating the loss of solution gas and preserving the reservoir's energy potential.

The optimization results highlight the significance of timely water injection initiation in maximizing recovery factors for this particular reservoir. By proactively managing the reservoir pressure and minimizing solution gas production, the optimized strategy effectively harnessed the available drive mechanisms, ultimately improving the overall recovery efficiency.

## **4.2 DISCUSSION**

A comparative analysis of the average reservoir pressure and gas-oil ratio (GOR) graphs for the water injection and optimized water injection cases reveals the significant impact of initiating water injection earlier in the field development process. In the optimized scenario, where water injection commenced at an earlier stage (3,015 days or 1997), a noticeable reduction in GOR was observed compared to the conventional water injection approach as seen in figure 4.9 below. 'GOR 1' indicates the GOR during the water injection and 'GOR 2' indicates that of the optimized case. The minimization of GOR in the optimized case can be attributed to the proactive management of reservoir pressure through early water injection. By maintaining the reservoir pressure above the bubble point, the liberation of solution gas from the crude oil was effectively mitigated as shown

in figure 4.10. Consequently, the reservoir's natural energy drive was better preserved, contributing to improved hydrocarbon recovery efficiency.

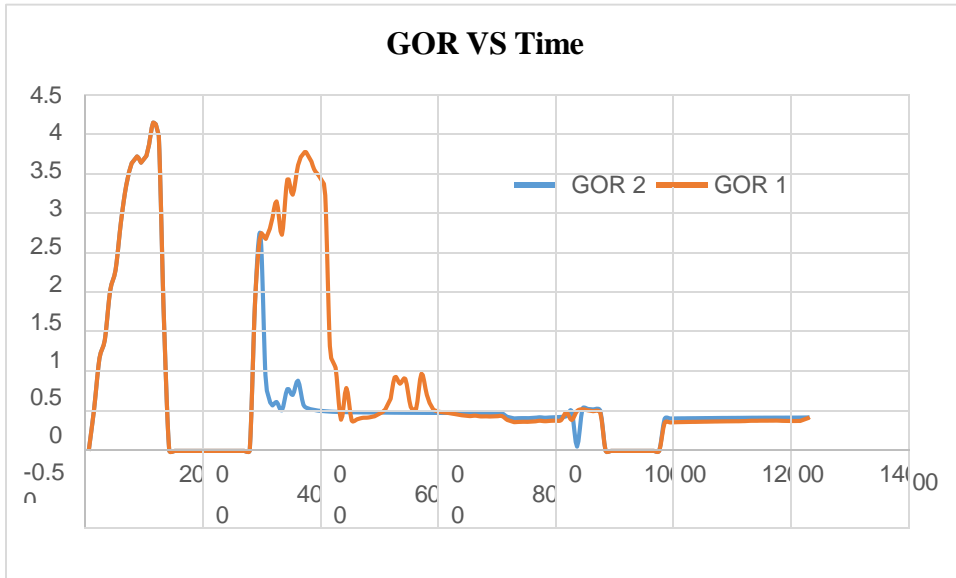


Figure 4. 9 Graph of GOR in both cases against Time

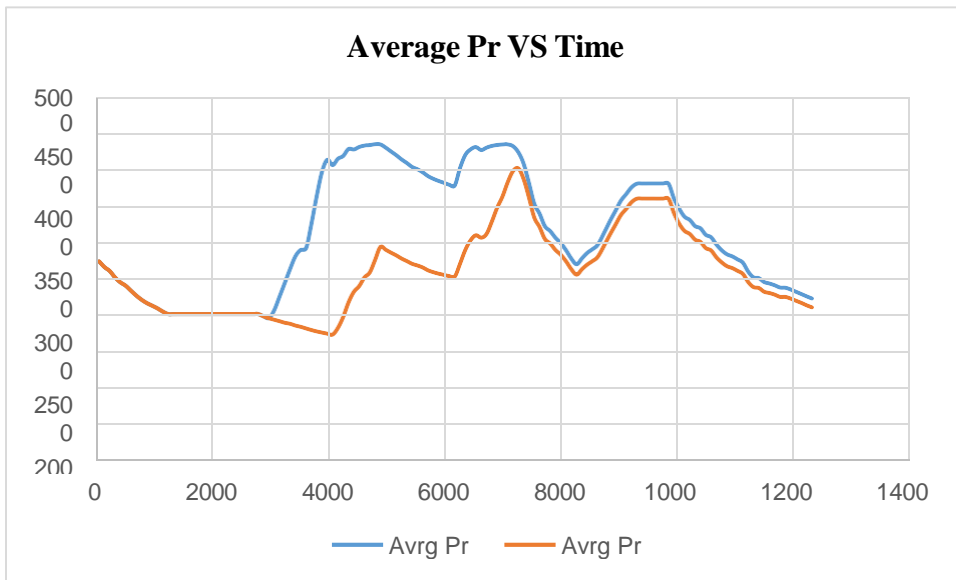


Figure 4. 10 Graph of Average Reservoir Pressure in both Cases against Time

The numerical results further corroborate the benefits of the optimized water injection strategy. As illustrated in the recovery factor (RF) graph in figure 4.11, performing water injection earlier in the IZYP field led to a substantial increase in the recovery at any time in the life of the reservoir, RF 2, when compared to the water injection case of before (RF 1). Specifically, the optimized approach yielded an ultimate recovery factor of 32.6%, representing a significant improvement over the 28.5% recovery achieved with the conventional water injection strategy.

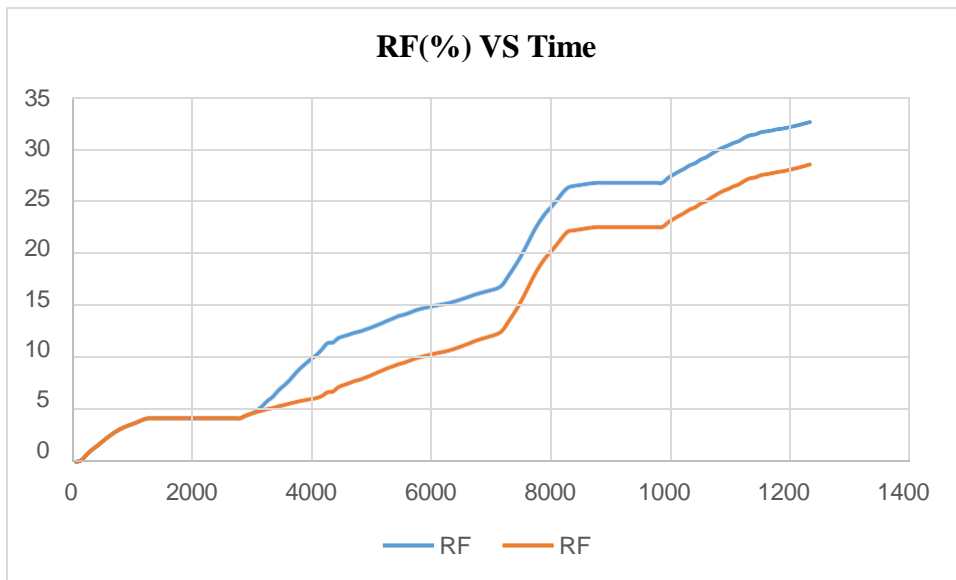


Figure 4. 11 Recovery factor in both cases against Time

These findings underscore the importance of timely and strategic reservoir management practices, particularly in fields with combined drive mechanisms involving both aquifer and solution gas. By proactively addressing the challenges of solution gas production and pressure depletion, the optimized water injection strategy effectively maximized the recovery potential of the IZYP field.

It is worth noting that while the optimized approach demonstrates promising results, further optimization opportunities may exist by exploring alternative well configurations, injection patterns, or operational strategies tailored to the specific reservoir characteristics and production constraints of the IZYP field.

## CHAPTER FIVE

### CONCLUSION AND RECOMMENDATIONS

#### 5.1 CONCLUSION

The following conclusion could be drawn from this study;

1. A representative reservoir simulation model was successfully developed for the IZYP field through history matching, enabling reliable predictions of future performance.
2. The conventional water injection strategy implemented in the IZYP field initially helped maintain reservoir pressure and mitigate solution gas production, but its effectiveness was limited due to the late initiation of water injection.
3. Introducing water injection at an earlier stage in the field development process (3,015 days or 1997) resulted in a significant improvement in overall oil recovery factors, increasing from 28.5% to 32.6% after 34 years of production.
4. The optimized water injection strategy, with earlier initiation, effectively minimized the loss of solution gas and maintained reservoir pressure above the bubble point, preserving the reservoir's natural energy drive and contributing to enhanced recovery efficiency.
5. The optimization process identified the most favorable combination of water injection well locations and injection rates, tailored to the specific characteristics of the IZYP field, leading to maximized hydrocarbon recovery within practical operational constraints.
6. The study highlighted the intricate interplay between reservoir pressure management, solution gas behavior, and recovery efficiency in fields with combined drive mechanisms, emphasizing the importance of proactive reservoir management strategies.

7. The optimized water injection approach demonstrated the potential for significant improvements in resource utilization and economic viability, making it a viable field development strategy for the IZYP field and potentially other similar reservoirs.

## **5.2 RECOMMENDATIONS**

The following recommendations are suggested:

1. Early implementation of water injection: It is recommended to initiate water injection at an earlier stage in the field development process, as demonstrated by the significant improvement in recovery factors achieved through the optimized water injection strategy. Early water injection helps maintain reservoir pressure above the bubble point, mitigating solution gas production and preserving the reservoir's natural energy drive.
2. Periodic re-evaluation and optimization: Continuous monitoring and periodic re-evaluation of the water injection strategy are recommended to account for changing reservoir conditions and production patterns. Regular optimization exercises should be conducted to identify opportunities for further enhancing recovery factors by adjusting injection rates, well locations, or operational strategies.
3. Integrated reservoir management approach: An integrated reservoir management approach should be adopted, considering the interplay between various reservoir parameters, drive mechanisms, and operational constraints. This holistic approach can help identify synergies and trade-offs between different recovery techniques, leading to more informed decision-making processes.

4. Reservoir surveillance and monitoring: Robust reservoir surveillance and monitoring programs should be implemented to collect accurate and timely data on reservoir pressures, fluid saturations, and production rates. This data is crucial for history matching, model calibration, and optimization efforts, ensuring that the reservoir simulation models remain representative of the actual field conditions.

5. Collaboration and knowledge sharing: Fostering collaboration and knowledge sharing within the industry is recommended, particularly for fields with similar characteristics or drive mechanisms. Sharing best practices, lessons learned, and successful strategies can accelerate the adoption of optimized recovery techniques and improve overall resource utilization efficiency.

6. Economic and feasibility analyses: Detailed economic and feasibility analyses should be conducted to evaluate the potential benefits of implementing the optimized water injection strategy against the associated costs and operational complexities. This evaluation can help determine the economic viability and potential return on investment for the proposed optimization measures.

7. Training and capacity building: Investing in training and capacity building programs for reservoir engineers, production engineers, and other relevant personnel is recommended. This can ensure that the necessary expertise is available to execute the optimized water injection strategy effectively and adapt to evolving reservoir conditions and technological advancements.

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