

**Federal Republic of Iraq
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**Mathematical Modeling for Simulating PPG gels in Mature Oil Fields
to Fractures in Network-Structured Carbonate Reservoirs.**

**A project submitted to the College of Engineering at Al-Kitab
University as a partial fulfilment for the degree of Bachelor of Science
in Petroleum Engineering.**

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ABSTRACT

Mature oil fields face sustained production challenges due to fractures that develop over time, leading to decreased reservoir performance. In order to predict the use of PPG gels, this study proposes novel mathematical modeling to be used in mature reservoirs to plug a fracture that has a network structural heterogeneity. For a more accurate representation of actual environmental circumstances, this model was modified by correlating screen test model results with fracture model experiment results. This modification enhances the accuracy of calculating pressure gradient and effective viscosity through fractures with network structural heterogeneity and extends the economic life of these assets. To validate the effectiveness of the model, simulations were executed using the Nimezida 2014 hydrodynamic simulator to simulate the known type of naturally fractured reservoir with a network structural heterogeneity of a real case, which is the Ekofisk oil field located in the northern region of the Norwegian sector in the North Sea. The tangible impact of gel injection revealed that with a pumped screen, the accumulated production over 200 days increased to 7995.2 tons, with low effect of gel injection into the network fracture of only 5 tons. However, the study presents more optimistic prospects over an extended period, considering that at least 40% of the injected gel remains in the fracture. The results showed the effectiveness of applying PPG gel technology to seal fractures, accounting for the heterogeneity of the network structure and filtered water in a low-permeability oil field area. The current approach significantly enhances the production and performance of reservoirs in existing oil fields and can be applied in Iraqi fields.

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CHAPTER ONE

INTRODUCTION

1.1.Introduction

Primary and secondary recovery techniques together are able to recover only about 20-40% of the original oil in place (OOIP). The primary and secondary recovery leaves a significant amount of oil remaining in the reservoir. Primary recovery normally refers to production using the energy inherent in the reservoir from gas under pressure or a natural water drive. Secondary recovery usually refers to injection of water or water flooding.

Enhanced oil recovery (EOR) is a process used to extract the residual oil left in the reservoir; this process is also called tertiary recovery. EOR techniques increase the amount of crude oil that can be extracted from an oil field. They permit extraction of 30-60% or more of the reservoir's original oil. EOR is achieved by gas injection, chemical injection, ultrasonic stimulation, microbial injection, or thermal recovery. The latter includes water injection, cyclic steam injection, steam flooding, and in-situ combustion

PPGs improve oil productivity and water injectivity. The PPGs control the production of unwanted fluid. They are cheaper than other EOR techniques. Additionally, PPGs require less equipment for surface preparation.

The method selected to control water production can affect the life of a reservoir. Gel treatment is the most effective and cost-effective means to decrease water production and improve reservoir homogeneity in mature oil fields. PPGs reduce water production by plugging the high-permeability formation without damaging the production zone.

In-situ gels are used widely to control conformance. A new gel treatment method uses PPGs to overcome the restrictions of the in-situ gels. Gel particles vary in diameter from nanometers to a few millimeters. Selecting the right particle size and strength is important for the success of the gel treatment. It is also important to understand the behavior of the gel in the porous media as it flows through the fractures and the channels of the high-permeability zone. Research on PPGs has focused on the swelling rate, swelling gel strength, and flow resistance factors.

Reducing production of associated water is one of the aims in oil fields that are at a later stage of development. Reservoir heterogeneities affect the flow of gas, oil and water in the reservoir and thus influence the choice of field development strategy. Reservoir heterogeneities are the most important reason for low oil production and early water cut. Many of the older fields have fractures or channels of high permeability due to the impact on the rocks of the injected water.

Gel treatment is one of the most important methods for correcting formation heterogeneity. Remaining oil in low permeability layers is the most important target for enhanced oil recovery. And various types of gel have been used to improve oil recovery. These gels are known to penetrate deeply into areas of higher permeability or into fractures and allow them to partially shut off and create high resistance to water flow.

1.2.Objective

The ultimate goal is to develop a method which could be used in mature oil fields to plug the high-permeable layers and filter the brine into the low-permeable layers to produce remaining oil from the low-permeable zone and decrease water production.

The object of the study is a heterogeneous oil reservoir with technogenic and natural fractures, and the subject is preformed particle gels (PPG) for blocking technogenic fractures and highly permeable zones in productive reservoirs.

CHAPTER TWO

LITERATURE REVIEW

2.1.Reduction of Water Production

Water production is one of the most crucial issues in petroleum engineering. Water is the most abundant fluid in an oil field, and it is produced along with oil (Kuchuk et al. 1999). Due to long term water flooding, excess water production has become major problem for operations in mature oil field (Bai 2008). Oil field operators have conducted many studies to evaluate the drawbacks of water production. They have found that damages surface equipment and casing leaking.

Excess water reduces hydrocarbon production, it increases costs related to disposal, scale, corrosion, water/oil separation, and other factors (Dalrymple 1997). Excess water production has become a significant concern for oil field operators because it reduce hydrocarbon production even in formation zones that still carry a considerable volume of hydrocarbons (Sydank 2000). Up to 65% of a reserve may remain after water flooding. Currently, three barrels of water are produced for each barrel of oil (Bailey et al., 2000).

The situation is even worse in the United States, where more than seven barrels of water are produced for each barrel of oil (EPA 1999). The annual cost of treating and removing of this water is estimated to be \$ 40 billion (Bailey et al. 2000). The Zuitina and Alwaha oil companies in Libya have observed that water production has increased over the last few years; reaching a maximum water cut of 95%.

Several processes have been proposed to reduce channeling of fluids through fractures and streaks of very high permeability in reservoirs. Processes that use crosslinked polymers or other types of gels have been most common. This analysis will focus on the placement characteristics and permeability-reduction properties of PPGs. Fractures and channels in the porous media are mainly responsible for decreasing productivity. The large volumes of injection water enter the channels and fractures. PPGs solve this problem by plugging the fractures and channels.

Heterogeneity affects the flow of gas, oil, and water in the reservoir and influences the choice of production strategies, reservoir management techniques, and ultimately oil recovery methods (Bai 2004). Reservoir heterogeneity is the single most important reason for low oil recovery and early excess water production. Field experience has demonstrated that the selection of candidate wells is critical to the success of gel treatments (Seright et al. 2003). Since 1995, PPGs have been successfully synthesized and applied to control excess water production in some mature water-flooded oilfields in China (Bai 2004).

Gel treatment is one of the most important methods to correct the reservoir heterogeneity. Water shutoff and conformance control, therefore, represent significant financial and environmental challenges for the petroleum industry. Gels have been used extensively in field applications to suppress excess water production and improve oil productivity (Seright et al. 2003).

Production of hydrocarbons is usually accompanied by the production of water. This water consists of formation water and/or water that have been injected into the formation. Water production increases over the life of a reservoir. Unfortunately, the water produced from oil reservoirs is not marketable; therefore, operators must find ways to handle relatively large amounts of water in an environmentally acceptable manner at the lowest possible cost.

Several researchers have studied the filtration on cores that are 100% saturated with brine, oil, or residual oil while injecting suspended particles; oily water, or a combination of both. However, no one has studied the effect of PPGs on mature oil fields with low- permeability zones and various concentrations of the brine. This research will use such cores to approximate more closely the effects of PPGs on conditions in the region around a wellbore.

2.2.Motivation

Mature reservoirs are requiring us to use PPG to control conformance. Most reservoirs in my company Zuetina Oil Company have become mature due to long term of water flooding. These reservoirs have a high average water cut of more than 95%. There water production becomes a major problem as these oilfields mature. The production water causes a damage to the wellhead equipment's, tubing inside the wellbore, production pumps short life, burn the cable of the electric submersible pump, and casing leaking do to the corrosion. Also, the corrosion makes a scale which may plug the perforation and decrease the productivity of the oil. Likewise, it will cost a lot of money for work over.

Higher levels of water production increased environmental concerns, and eventually well shut-in. Controlling water production has been one objective of the oil industry in mature oil fields. Reservoir heterogeneity affects the flow of gas, oil, and water in the reservoir and thus affects the choice of production strategies, reservoir management, and choosing the right method of oil recovery. Reservoir heterogeneity is the single most important reason for low oil recovery and early excess water production. Many of the mature oil have fractures or high-permeability channels due to mineral dissolution and production during waterflooding (Liu, 2006).

Gel treatment is one of the most important methods to correct the reservoir heterogeneity. The remaining oil in the low permeability layers is the most important target to improve oil recovery as a reservoir matures. A various types of gel have been applies in purpose of improve the oil production (Seright, 2004, Frampton, 2004, Sydansk, 2005, Chang, 2004, Rousseau, 2005, Bai, 2007). These gels have been reported to penetrate deeply into higher permeability zones or fractures and plug or partially plug them and construct high flow resistance in previous.

2.3. Chemical Materials for Water Shut Off

Many chemical systems have been used to control water and improve recovery from reservoirs with a high water cut.

Koch and McLaughlin (1970) used an inorganic gel to change the injection profiles in waterflood injection wells. The results indicated that the material and techniques may be applied to control water breakthrough problems in waterflood producing wells.

Chen (1988) examined a non polymer in-situ gelling system for water control treatments. Inorganic gels have a viscosity close to that of water and can be pumped using field mixing and injection equipment.

Silicate gels have been used to repair casing leaks and decrease water production for many years because they are inexpensive and they form strong gels. Sodium silicate solutions however cannot deeply penetrate the formation, and methods to retard gelation are not effective in some cases (Viont et al. 1989; Grattoni et al. 2001; Bauer et al. 2005; Burns et al. 2008).

Polymer or crossed-linked gels, especially those based on polyacrylamide, are used largely because of their relatively low cost and selectivity; they only reduce relative permeability to water. Nanda et al. (1987) studied the characterization of polyacrylamine-Cr⁶⁺ gels used for reducing water-to-oil ratio. They observed that polyacrylamide with chromium ions geled through coordination bonding with nitrogen.

Liang et al. (1992) found that gels reduced water permeability more than oil permeability. Herbas et al. (2004) developed a model to study a polymer gel treatment in a pilot test to improve injection profiles and sweep efficiency in a water injector. Recently, in-situ gels have been studied as water control systems for high-temperature reservoirs (Peng 1998; Li and Wu 2000; Wang 2007; Al-Muntasheri et al. 2007).

Chang et al. (2004) and Al-Assi et al. (2009) prepared colloidal dispersion gels (CDGs) by crosslinking low- concentration polymer solutions with a small amount of chromium acetate or aluminum citrate. Spildo et al. (2009) investigated the applicability of CDG at high-salinity (35,000 ppm) sandstone reservoirs. Their results were positive, but the crosslinking reaction required a week to complete.

Chauveteau et al. (2001, 2003, and 2004) developed a microgel system for water control. Microgels are colloidal particles of acrylamide crosslinked with zirconium. The size of the microgels (polymer aggregate) can be changed during shearing; however, microgel properties are affected by salinity, pH, and shear rate, and microgel resistance is weak.

Bai et al. (2008), Dalrymple et al. (2008), and Wu and Bai (2008) have used PPGs to modify the water injecting profile. An ideal chemical system for reservoir water control should have the following properties: tolerance for high salinity and hardness, compatibility with any mixed water, thermal stability, low viscosity, the ability to penetrate a deep formation, insensitivity to shear rate, and pumping capability (Chen 1988). The present work will study the efficiency of a variety of PPGs in low-permeability to determine the reducing ratio of the rock permeability. It will vary the constant flow rate and constant back pressure with room temperature.

CHAPTER THREE

THEORETICAL BACKGROUND

3.1. Conformance Control

Conformance control refers to the technologies that use chemical or mechanical methods to reduce water production by plugging the source of water production from the wellbore, high permeability layers, channels or fractures in the reservoirs. The main reasons for decline in the hydrocarbon production are the heterogeneity and the high water cut.

3.2. Types of Gels Used for Conformance Control

Gel properties are mainly depending on the chemical composition of the gel including polymer concentration and the degree of the crosslinking in the gel. Gel treatment could be applied using different types of gel with various chemical composition and different size. There are two types of gel using in oil industry during those days as gel treatment:

3.2.1. In-Situ Gel

In-situ gel is crosslinked polymer composed from several chemical material including polymer, crosslinker, and additives. The liquid formulation of this composition is called gelant. An in-situ system, the gelant is injected into the formation and the gel is formed under reservoir conditions. Conditions, such as increasing temperature or changing pH, the gelant can crosslink to form a gel. Gel strength can be controlled by gelant composition and surrounding conditions; it can be weak, like a flowing gel, or very rigid, like rubber (see fig.3.1). The first application of the polymer gels—partially hydrolyzed polyacrylamide for conformance control of oil reservoirs was in the 1970s the gel form under the reservoir condition.

Traditionally in-situ gels have been widely used to control conformance, but they have several disadvantages: Crosslinking reactions are strongly affected by degradation (caused by the pump, by the well bore, and by the porous media). They promote adsorption and chromatography of chemical compositions, and they dilute formation water, however, in-situ gels behave as a polymer solution when they are injected as gelants.

According to polymer flooding mechanisms, more gelants will sweep into unswept low-permeability oil zones. Once the gelants crosslink in these oil zones, not only will they waste polymer, but they will also block these zones, causing serious damage in these potentially productive oil zones. PPGs, however can effectively reduce gel damage on unswept low-permeability oil zones. Most gels cannot penetrate into a few millidarcy of formation permeability.

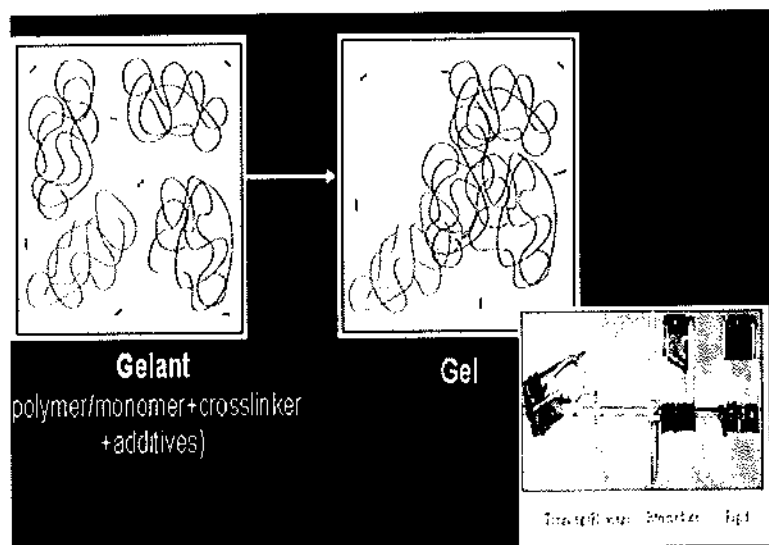


Fig. 3.1- Gel composition

3.2.2 Preformed Particle Gels (PPGs)

PPGs are a dried crosslinked polyacrylamide powder when they come in contact with water; they can swell several to a few hundred times their original size. PPG is super-absorbent polymer have been applied successfully to control conformance in mature oil fields around the world. PPGs represent a new type of SAP developed for conformance control purposes. In Preformed gel systems, the gel is formed in surface facilities before injection, and then injected into reservoirs. No gelation occurs in the reservoir. Figure (3.2) shows the PPGs before and after swollen.

Gel treatments are a cost-effective method to improve sweep efficiency in reservoirs and reduce water production in mature oil fields. PPGs can overcome some distinct drawbacks inherent in in-situ gelation, such as an incapability to control gelation time, uncertainty of gelling due to shear degradation, chromatographic fractionation or change in gelant compositions, and dilution by formation water.

Table 3.1. Summarizes the different kinds of gels used in oil industry.

Name of the Preformed Gels	Authors
preformed bulk gels	(Seright 2004),
partially preformed gels	Sydansk 2004, 2005),
particle gels that include PPGs	(Coste 2000; Bai 2007),
Microgels	(Chauveteau 2000, 2001; Rousseau 2005; Zaitoun 2007),
PH sensitive crosslinked polymers	(Al-Anazi 2002; Huh 2005),
milimeter-sized swelling polymer grains	grains (currently marketed by service companies),
Bright Water	(Pritchett 2003; Frampton 2004).

The major differences among these PPG are particle size and swelling time. Microgels (U.S. patent 6579909) and BrightWater (U.S. patent 6984705) are patented products, but both are commercially available. PPGs, microgels, and BrightWater have been used economically to reduce water production in mature oilfields. PPGs have been applied in about 2,000 wells in china to reduce fluid channels in waterfloods and polymer floods (Liu 2006).

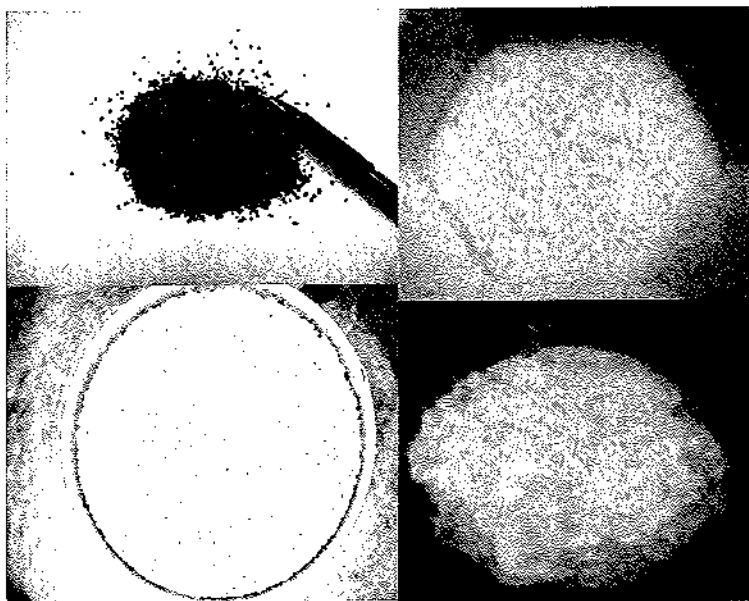


Fig. 3.2. PPGs before and after swelling

Gel treatment is one of the most important methods to correct the reservoir heterogeneity. Traditionally, gels have been placed near the wellbore of production or injection wells, as shown in Fig.3.3, to correct inter layer heterogeneity or fractures. However, the oil remaining on top of a thick heterogeneous layer is the most important target of oil recovery efforts as a reservoir matures. A newer trend in gel treatment is to apply in-depth diversion products (Seright 2004; Frampton 2004; Sydansk 2005; Chang 2004; Rousseau 2005; Bai 2007), which have been reported to penetrate deeply into high-permeability zones or fractures, sealing or partially sealing them and thus creating high flow resistance in formerly watered out, high-permeability zones. When successful, these gel systems divert a portion of the injection water into areas not previously swept by water, as shown in Fig.3.3.

Excess water caused by reservoir problems can usually be handled with either near-well bore treatment or in-depth treatment. If there is no crossflow between low-permeability and high-permeability zones, a small amount of gel can be injected near the wellbore. A gel placed in the high-permeability zone near the injection well bore (as in fig.3.3) will reduce the permeability of that zone, and more water will penetrate into the low-permeability zone; therefore, the injection profile must be controlled. On the other hand, if the gel is placed near the production well bore (as shown in fig.2.3b), it will reduce the permeability of the high-permeability zone so that more oil can be produced from the low-permeability zone, thus reducing the water cut and improving oil production. If there is cross-flow between layers, in-depth gel treatment is required. In this case, gel is injected from an injection well rather than from a production well. The large volume of gel placed in the high-permeability zone will divert followed water to low-permeability zone; displacing the remaining oil.

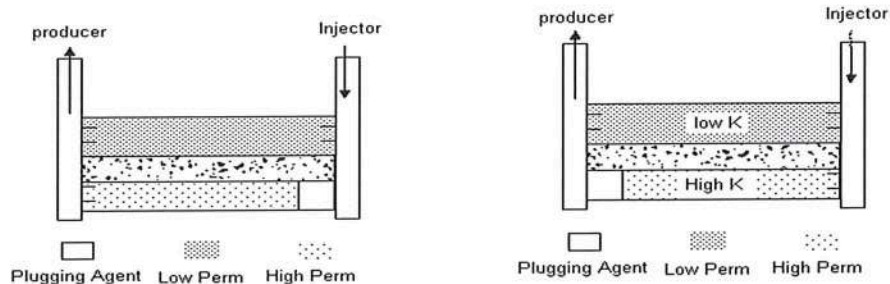


Fig. 3.3. Gel treatment for heterogeneous formation without crossflow.

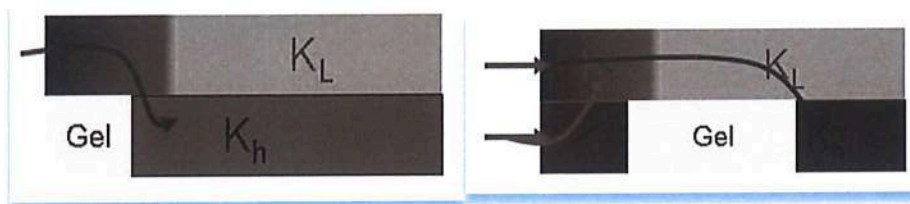


Fig. 3.4. Gel treatment for heterogeneous formation with crossflow.

3.2.2.1. Importance and Advantage of PPG

Waterflooding significantly changes reservoir pore structures and physical parameters. Induced fractures or high-permeability streaks and channel are common in mature reservoirs. Many kinds of particles, such as montmorillonite clay, are often applied to control conformance. Many wells injected with thousands of cubic meters of 5-10% clay have encountered on problems. Particle injection practices suggest that formations have more serious voids or fractures than expected. Moreover, lab tests have shown that PPGs with large particles will not plug the low-permeable zone.

PPGs Particle Size can be adjustable from a scale of micrometers to millimeters. They have a swelling ratio of 30~200 times from the original volume, PPG/water ratio. Their resistance to salt permits the use of all salt types and concentrations. They are resistant to temperature up to 110 °C. They remain stable for more than 1 year below 110 °C.

The size of particle use is adjustable, ranging from microns to centimeters. The PPGs swelling r can be controlled somewhat the concentrations of the brine solution. They are resistant to all kinds of formation salts at many concentrations. They remain stable for over a year at temperatures below 110 °C. PPGs are available with high-strength.

3.2.2.2. PPG Application

In 1996, RIPED petrochina became the first oil field operators to test large volumes of PPG to control conformance. The first successful application of such treatments occurred in 1999 when applied large volumes of PPG in the Zhongyuan oil field, in a reservoir with extreme conditions: temperatures of 107 °C and salinity of 150,000 mg/l. About 2,000 wells have been treated using PPG.

3.2.2.3. Well Selection for Using PPGs

Oil wells to be treated with PPG must meet: Reservoir temperature below 120°C, High-permeability channels or fractures, High injectivity and low PI (productivity index), High water cut and high liquid rate of connected producers, Well group with low oil recovery preferential, Unlimited salinity. [Before injection water tracer and, well tests should be run and a water absorption profile developed.

3.2.2.4. Mechanism of the PPGs on Mature Reservoirs

Oil field productivity increases in a low-permeability zone when a particle gel plugs the high-permeability zone and filters water into the low-permeability area; thus, sweep efficiency improves. Figure (3.5) illustrates the injection first of particle gel then of brine to plug the high-permeability formation and allow the brine to enter the low-permeability zone, thus increasing the rate of oil recovery. After the brine is injected into the formation, the wellbore must be cleaned to remove the swelling particle gel.

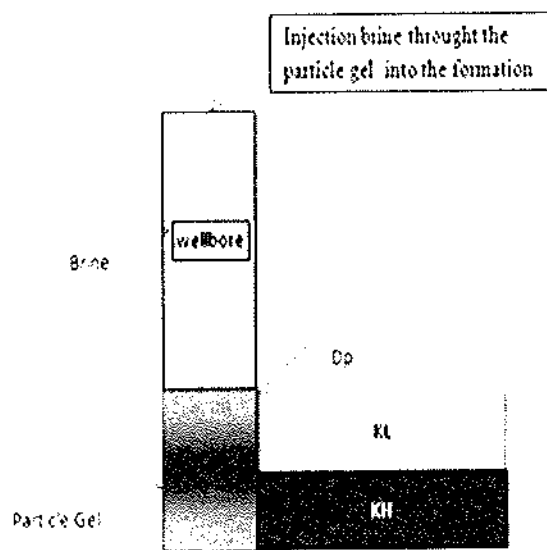


Fig.3.5. Mechanism of PPG on the formation zone.

CHAPTER FOUR

MATHEMATICAL MODELING

The objective of this work is to create models that may be utilized to forecast the effective viscosity of swelling PPG gels as it is being forced through a fracture with network structural heterogeneity. Assuming that particle gel is a shear-thinning material and obeys a power-law rheology equation, we first created a theoretical model to forecast the pressure gradient of swelling particle gel extrusion via an open fracture. But a typical rheology measuring instrument, a rheometer was unable to identify the parameters to characterize particle gel rheology in the theoretical model. In order to ascertain if it might be utilized to ascertain the rheology characteristics of swelling particle gel, we employed a basic screen model. Correlating the fracture experiment findings with screen experiment results allowed for the modification of the theoretical model in light of the distinctions between screen tests and actual rheology testing. A screen experiment is considerably easier and requires less time to conduct than the findings of the fracture experiment.

In order to avoid overlapping the effects of bottom water, the movement of which along vertical fractures has a huge negative impact on the oil recovery process, we will depend on the effects of fracture plugging associated only with injected water. As the main tool for testing the proposed fracture screening technology, we will rely on the hydrodynamic modeling of the hydrodynamic model, i.e., on the results of computational experiments on the reservoir simulation model of the prototype.

Nimezida 2014 hydrodynamic simulator is used in this study. This program is licensed and accessible in various Russian laboratories including Tyumen State University where these experiments carried out. It has been designed with extensive functionality for complex fracture simulations (Zhang and Sheng, 2020). Because of its special features, which allow for in-depth examination of fluid movement inside fractures, it is an excellent fit for this study. Furthermore, this software provides advanced functionalities and customization options that are not readily available in conventional fluid flow analysis software. As a result, we were able to conduct a more detailed and comprehensive analysis, leading to deeper understanding into the behavior of the screen simulations model. Fig.4.1 presents a systematic approach to analyzing the impact of PPG gels treatment on reservoir performance. To comprehend the fluid dynamics within the fracture network, the pressure gradient of PPG gels flow via fracture with network structural heterogeneity is first computed, in addition to the effective gel viscosity. Then, taking into account different injection pressures, the saturation levels of water and oil throughout the reservoir are calculated following water injection but prior to gel treatment. Next, it is determined how saturated the PPG gel injection has become over time in the fracture. The fluid flow rates of water and oil are computed over time using Darcy's law. The total amount of oil produced both before and after the gel treatment is then calculated. Finally, to assess the efficacy of the PPG gel treatment approach, oil production rates are compared before and after gel treatment and the effect of network fracture on the oil production.

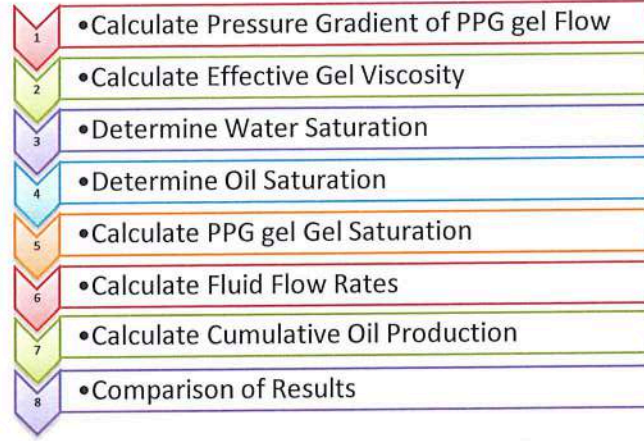


Fig.4.1. presents a systematic approach to analyzing the impact of PPG gels treatment on reservoir performance.

During the study of conditions of the hydrodynamic model, the bottom water will be absent. However, in the case of bottom water activity, the effect of the injection of the gel screen into the fracture with network structural heterogeneity will be even more significant, since it will prevent the vertical movement of water in the fractures. To study the technological effect of the gel, firstly, we will create a basic model, which will be obtained as a fragment of a development element, which is a rectangular parallelepiped with closed vertical edges (edge zones). The second important point is the choice of the absolute fracture permeability for the most reliable results of computational experiments. We will assume that the fracture is rectangular with a width much less than its length and height. Thus, according to the classical concepts of hydraulics, the flow in a slotted channel, when the gradient of the start of filtration (moving away) is exceeded, will correspond to a laminar flow, since:

$$Re = \frac{\omega D_r}{\nu} < 2300 \quad (4.1)$$

Laminar flow refers to small values of Re numbers (up to $Re \approx 2000$) and is characterized by the fact that the roughness has no significant effect on the hydraulic resistance. The value λ according to the Hagen-Poiseuille law (Sutera and Skalak, 1993):

$$\lambda = \frac{64}{Re} \quad (4.2)$$

Then we can assume that in this case the Darcy-Weisbach ratio known from hydraulics will be linear:

$$\Delta p_{mp} = \lambda \frac{L}{D_r} \frac{\rho \omega^2}{2} = ,$$

$$\begin{aligned}
&= \frac{64}{\frac{\omega D_f}{v}} \frac{L}{D_f} \frac{\rho \omega^2}{2} =, \\
&= v \frac{64L}{D_f^2} \frac{\rho \omega}{2} = \\
\Delta p_{mp} &= \frac{64L}{\left(\frac{4F}{\Pi}\right)^2} \frac{\mu \omega}{2}. \tag{4.3}
\end{aligned}$$

Here: ρ – fluid density; λ – hydraulic resistance coefficient; ω – flow velocity.

In other words, this allows us to identify the Darcy-Weisbach law with the linear Darcy filtration law by equating their right-hand sides:

$$\frac{\mu \omega}{k} L = \Delta p_{mp} = \frac{64 L}{\left(\frac{4 F}{\Pi}\right)^2} \frac{\mu \omega}{2}. \tag{4.4}$$

Where k refers to fracture permeability. With the precise knowledge of the linear dimensions of the fracture, one can discern its permeability, which can be safely substituted into Darcy's law, which is used in modeling the viscous friction within the current rectangular parallelepiped and pressure gradients as follows:

$$\begin{aligned}
\frac{1}{k} &= \frac{64}{\left(\frac{4 F}{\Pi}\right)^2} \frac{1}{2}. \\
k &= \frac{2 \left(\frac{4 F}{\Pi}\right)^2}{64} \\
k &= \frac{\left(\frac{4 F}{\Pi}\right)^2}{32} \tag{4.5}
\end{aligned}$$

Where k refers to fracture permeability. With the precise knowledge of the linear dimensions of the fracture, one can discern its permeability, which can be safely substituted into Darcy's law, which is used in modeling the viscous friction within the current rectangular parallelepiped and pressure gradients as follows:

$$k = 0.03125 \left(\frac{2w \times h}{(w + h)} \right)^2 \tag{4.6}$$

Since in the model the boundaries above and below are impermeable and the fracture is adjacent to the boundaries of the model from above and below, the height of the fracture - h in our case is equal to the thickness of the reservoir - 10 m. Thus, for a fracture thickness of 0.3 mm, the permeability will be:

$$k = 0.03125 \left(2 \frac{0.0003 \times 10}{(0.0003 + 10)} \right)^2 = 1.12497 \cdot 10^{-8} \text{ m}^2 \quad (4.7)$$

Accordingly, 11249.7 Darcy, and at 3 three millimeters about 1.12 million Darcy is recommended. In the model under consideration, the fracture is taken with a linear narrowing from 3 mm - 0.3 mm as it approaches the production well. Naturally, the fracture width is discretized according to the cells every 2 m.

To study the technological action of the gel in typical case when a fracture has a network structural heterogeneity, first, we created a new model, which obtained as a fragment of the development element, which is a rectangular parallelepiped with a size of 200x100x10 m with impenetrable boundaries as shown in Fig.4.2.

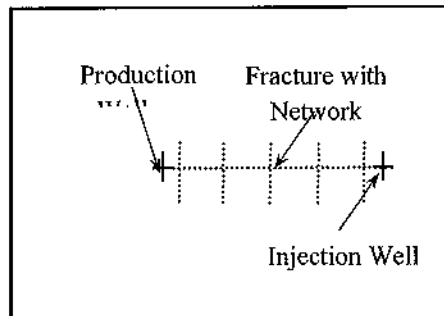


Fig.4.2 Sceme of the experiment for obtaining basic models for network fracture formation.

The distances from the injection and production wells to the boundaries of the formation along the X-axis are the same and amount to 50 m. The initial formation pressure delivers 49 MPa. The thickness of the formation is 10 m. Of course, all effects will proportionally increase with increasing thickness, since bottom water activity is not provided.

As the boundary conditions at the injection point, a water inflow of 100 t/day was recorded, i.e. pressure in this cell - P_{inj} is calculated at the hydrodynamic model. The production well is set with a fixed pressure $P_d = \text{const}$ in cell (50,50). Therefore, the inflow of water and oil into the cell is, in fact, the production rate of the production well and will be calculated.

The hydrodynamic model is configured as isolated, i.e. without constant pressure at the boundaries for the reason that otherwise the effect is camouflaged due to the influx of phases from the outside - from the side of the model boundaries. This can both diminish the effect and exaggerate it due to the fact that the balance of oil and water mass withdrawal will not be observed due to mass transfer through the open boundaries of the hydrodynamic model. Moreover, in this case, both inflow and outflow of masses are possible.

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CHAPTER FIVE

RESULTS AND DISCUSSION

The Ekofisk oil field has the original data as illustrated in Table 5.1.

Table 5.1. Sample of the petrophysical properties of the Ekofisk oil field.

Lithology	Chalk
The midpoint depth of the reservoir, m	3,169.92
The area of the reservoir, hectare	4884.96
The reservoir average porosity, %	31.7
The matrix average permeability of the reservoir, Darcy	0.001
The matrix permeability range, Darcy	.0001-0.01
The result of permeability from Well test analysis, Darcy	0.2
The reservoir pressure initially, MPa	49
The temperature at 3,169.92m of the reservoir, °C	131.11
The Saturation of the reservoir water, %	23.6
Initial Solubility of Gas, SCF/STB	1530
The oil formation volume factor initially, bbl/STB	1.78
The oil specific gravity, API	36

This segment presents visual investigation of the dynamic alterations in oil saturation fields that occur during hydrodynamic operation. The findings of this research compare situations with and without gel injection, presenting important new information on how well PPG gels affect reservoir fluid flow patterns.

On the basis of experimental data (Al-Assi et al., 2009) on the pumping of the gel through the fracture, we can be obtained the formulas to calculate pressure gradient of gel through the fracture has a network structural heterogeneity of the form (5.1) - (5.3).

Regression equation (5.1) obtained from experiments with a 160-mesh screen:

$$\frac{dp}{dl} = 39210k_a^{-0.0845} \left(\frac{2n_a+1}{n_a}\right)^{12.306n_a} \left(\frac{2q}{h}\right)^{1.442n_a} \left(\frac{1}{W^{2n_a+1}}\right)^{0.257} \quad (5.2)$$

K_a is the constant related to brine concentration and screen size.

Regression equation (5.3) obtained from experiments with 90 mesh screens $\frac{dp}{dl} =$

$$32154k_a^{-0.0942} \left(\frac{2n_a+1}{n_a}\right)^{13.475n_a} \left(\frac{2q}{h}\right)^{1.526n_a} \left(\frac{1}{W^{2n_a+1}}\right)^{0.253} \quad (5.3)$$

Regression equation (5.4) obtained from experiments with a 50 mesh screen:

$$\frac{dp}{dl} = 26303k_a^{-0.195} \left(\frac{2n_a+1}{n_a}\right)^{14.105n_a} \left(\frac{2q}{h}\right)^{1.464n_a} \left(\frac{1}{W^{2n_a+1}}\right)^{0.246} \quad (5.4)$$

Then, the effective gel viscosity of flow through the fracture has a network structural heterogeneity can be obtained by using newly correlated pressure gradient in Screen experiments model divided by the pressure drop of water equation.

For screen size 160-mesh, the effective gel viscosity is:

$$\mu_G = 3269.5K_a^{-0.0851} \left(\frac{2n_a+1}{n_a}\right)^{11.956n_a} \left(\frac{2q}{h}\right)^{1.442n_a} \left(\frac{1}{W^{2n_a+1}}\right)^{0.257} \left(\frac{hw^3}{q}\right) \quad (5.5)$$

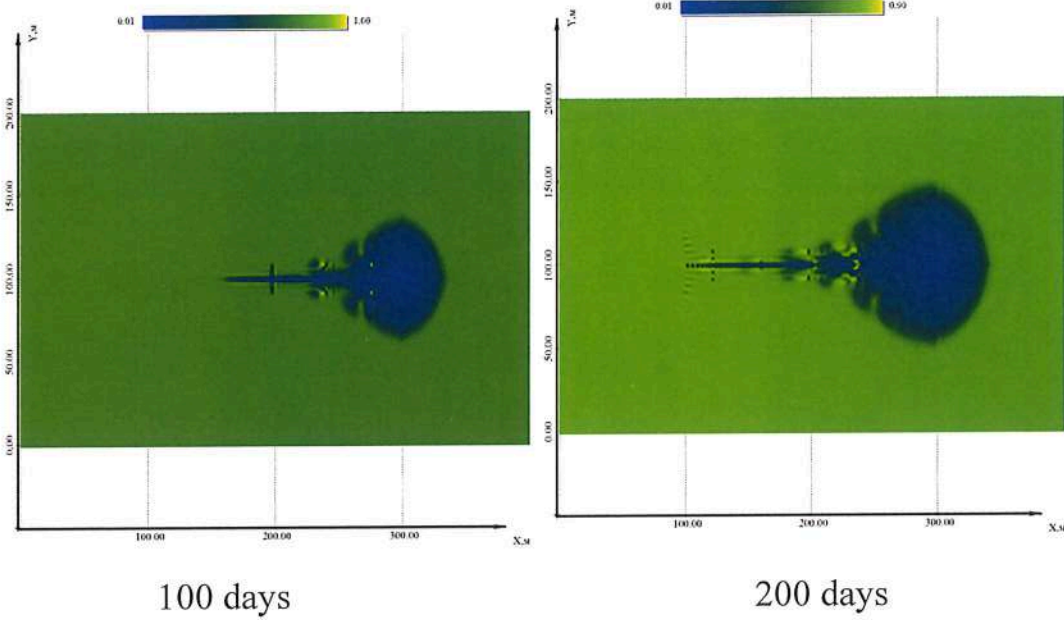
For screen size 90-mesh, the gel effective gel viscosity is:

$$\mu_G = 2680.5K_a^{-0.0942} \left(\frac{2n_a+1}{n_a}\right)^{13.475n_a} \left(\frac{2q}{h}\right)^{1.526n_a} \left(\frac{1}{w^{2n+1}}\right)^{0.253} \left(\frac{hw^3}{q}\right) \quad (5.6)$$

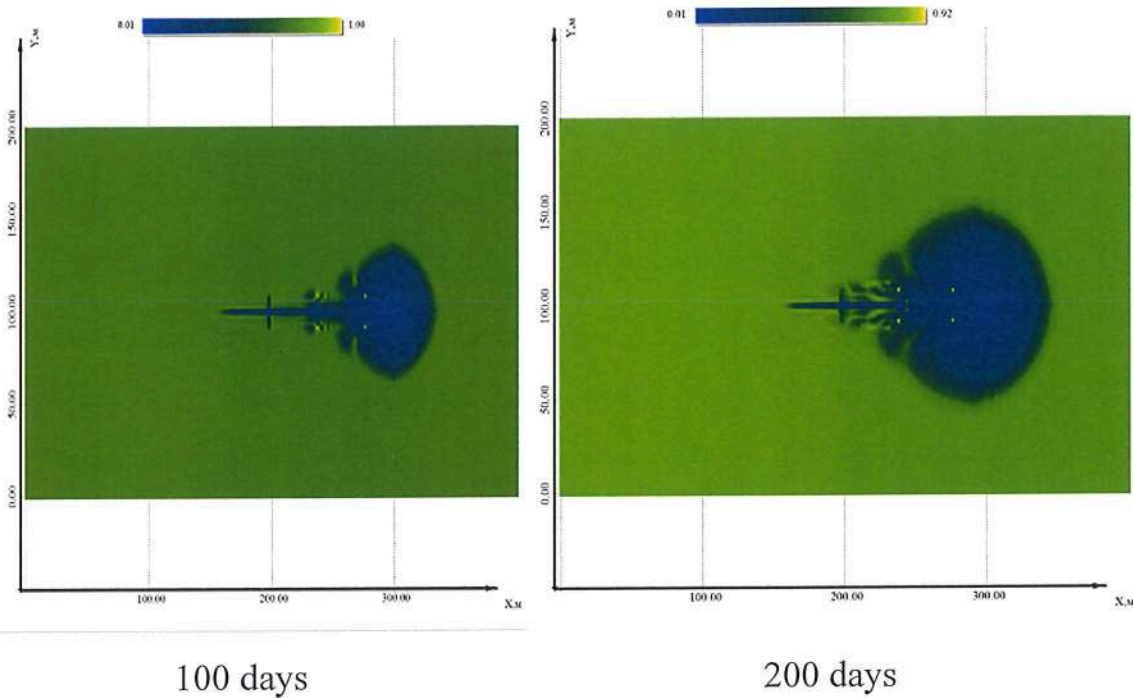
For screen size 50-mesh, the gel effective gel viscosity is:

$$\mu_G = 2193.9K_a^{-0.197} \left(\frac{2n_a+1}{n_a}\right)^{13.105n_a} \left(\frac{2q}{h}\right)^{1.464n_a} \left(\frac{1}{w^{2n+1}}\right)^{0.246} \left(\frac{hw^3}{q}\right) \quad (5.7)$$

Fig.5.1 shows comparisons of oil saturation fields at the time of 100 and 200 days from the beginning of the hydrodynamic operation under the conditions of injection of gel (A) without it (B) with gel.



(a)



(b)

Fig.5.1. Comparison of oil saturation with and without gel(a) Without gel; (b) With gel.

Comparison of the distribution of the oil streamlines demonstrates the wavy form of the oil stream after the injection of the gel is shown in Fig.5.2. In fact, oil is involved in displacement from the water side of the envelope, "plugged" with gel fracture branches. In other words, an important consequence of the gel-induced conformance control is the participation of oil in displacement from the water side of the envelope. The displacement pattern, which is distinguished by the wavy streamlines, highlights how well PPG gels modify reservoir dynamics. The gel addresses the issues of favored flow routes and low reservoir sweep efficiency by facilitating a more uniform and regulated sweep when oil passes through the "plugged" fracture branches.

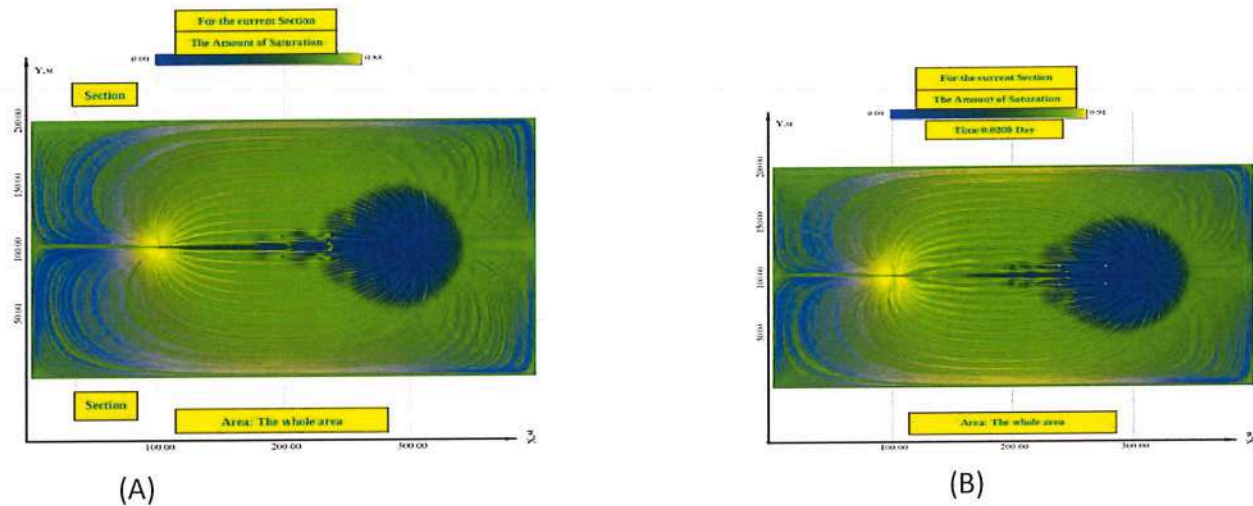


Fig.5.2. Comparison of oil saturation fields and oil flow lines by 200 days (a) Without gel; (b) With gel.

The nature of the flow rate curves for the hydrodynamic reservoir with a network fracture is somewhat different in that the flooding occurs somewhat earlier (125 days). In this case, the water oscillates somewhat, as presented in Fig.5.3. It is quite obvious that the structural hydrodynamic inhomogeneity manifests itself in this way.

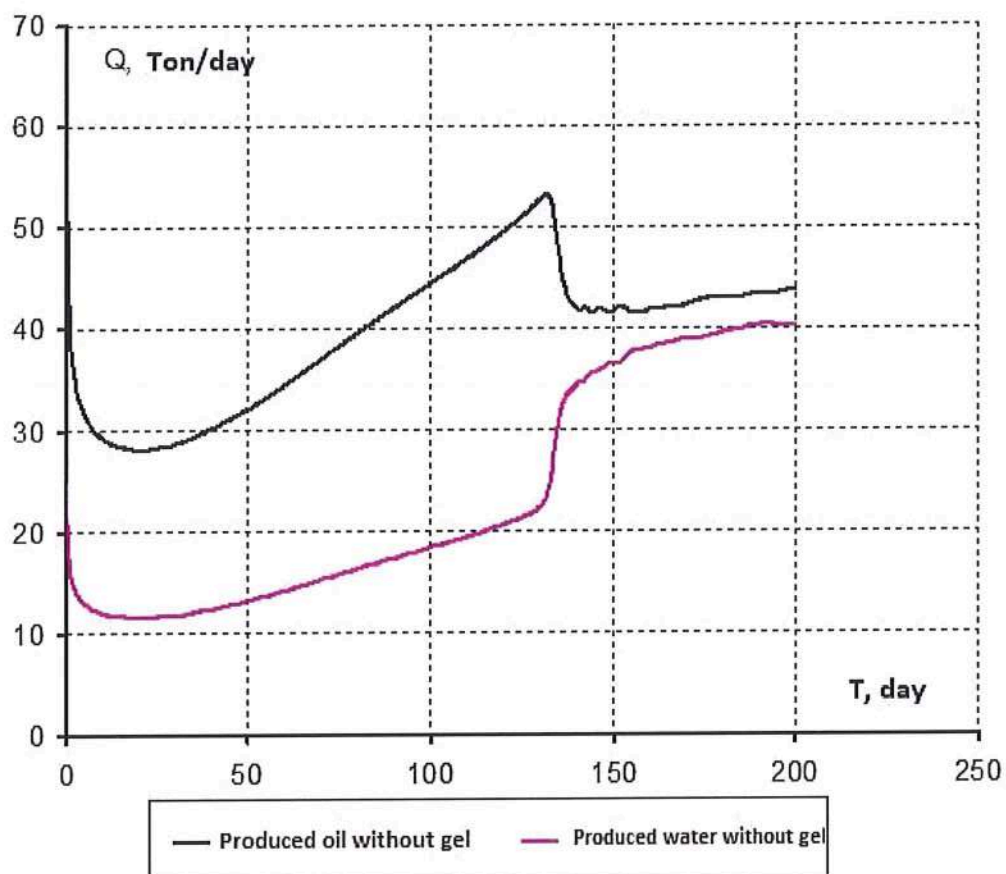


Fig.5.3. Dynamics of oil and water production in a system with a network fracture without injection of gel

After the injection of gel from the moment of 100 days, the fluid flow rate in the producing well drops sharply (by 11%) as shown in Fig.5.4, as the efficiency of water injection decreases, due to a decrease in the permeability of the reservoir hydraulic system. Comparison of cumulative oil production as shown in Fig.5.5 shows an extremely low effect from the injection of gel.

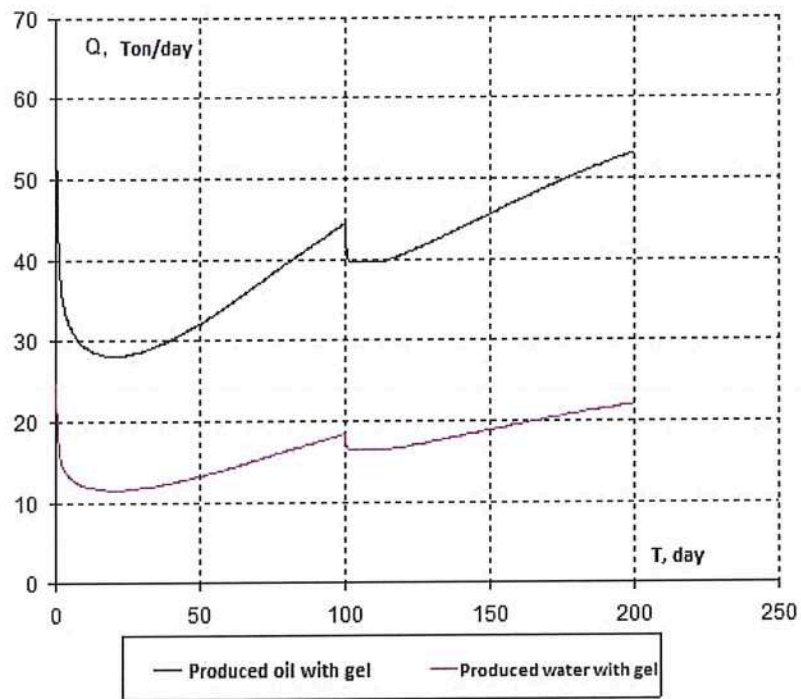


Fig.5.4. Dynamics of oil and water production rate in a system with a network fracture with gel injection.

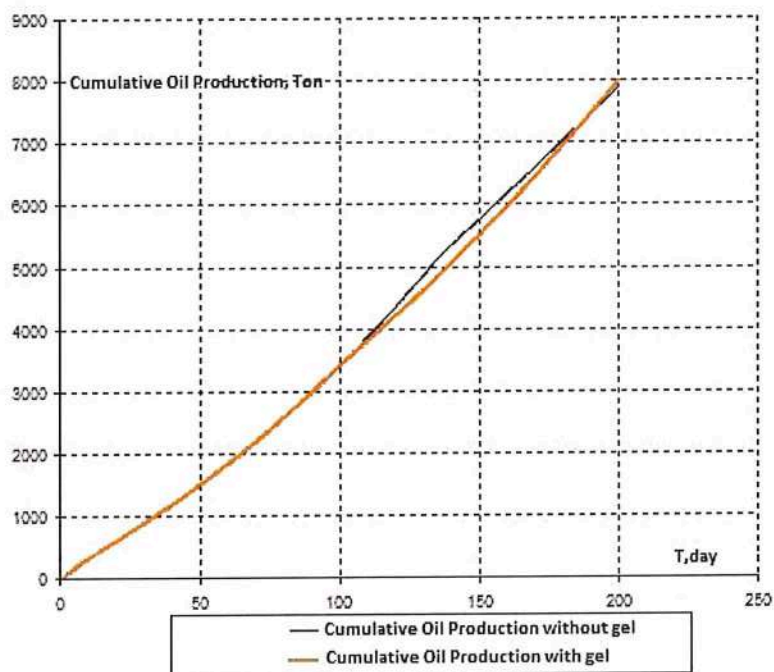
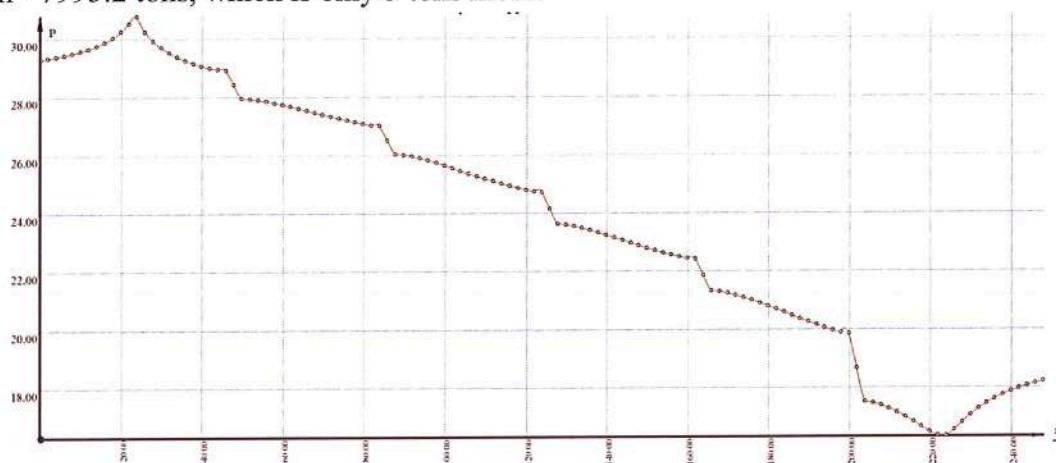
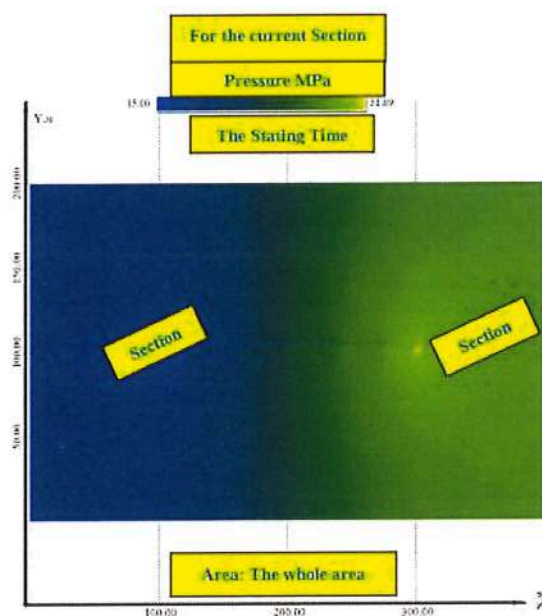


Fig.5.5. Comparison of cumulative oil production with and without well injection in a system with a network structure fractured.

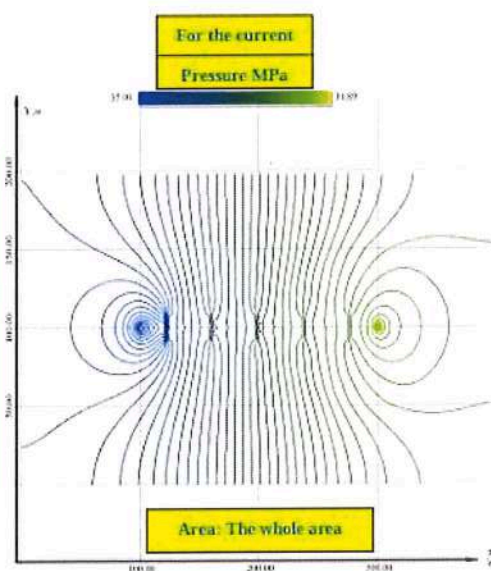
As a result of the application of gel injection into the network fracture, an extremely low effect was obtained: in the absence of a gel screen, the accumulated production amounted to 7990.0 tons per 200 days, and with the pumped screen - 7995.2 tons, which is only 5 tons more.



(a)



(b)



(c)

Fig.5.6. Distribution of pressure (MPa) in the hydrodynamic model with a network fracture after injection of the gel at the time of 200 days (a) Along the section; (b) Sectional diagram; (C) Isobars.

The weak effect is caused by the screening of the injection zone from the side of the fracture branches filled with gel, is shown in Fig.5.6. Thus, the effectiveness in terms of the intensity of the impact drops sharply. However, in a longer time it is more promising, and taking into account that at least 40% of the injected gel remains in the fracture, it should be assumed: over time, the effect will increase due to the movement of water around the shielded branches of the fracture. At the same time, since the water cut of the well still falls, it is possible to envisage a decrease in the bottomhole pressure to stimulate the flow.

The following can be used to briefly describe the study significant contributions to gel injection for reservoir compliance management:

- 1.The movement of the gel along the fracture for long distances (more than 100 m) is greatly hampered by the rheological properties of the gel and high kinematic viscosity exceeding 150 thousand Centistokes.
- 2.Injection of the gel into the injection well to obtain a greater effect should be carried out before water breakthrough through the fracture into the sampling zone. Otherwise, the effect will be reduced.
- 3.To increase the effect of the use of the gel, it can also be pumped into a production well when water from the waterflooding system has broken through into the production wells.
- 4.The risk of using the gel can be associated with the formation of new fractures in the injection zone, if the injection pressure is not limited and the injection time is not sustained enough to rebuild the pressure field, since the gel has pronounced rheological properties.
- 5.With the development of a network structure fracture as a result of gel injection, the displacement front is screened, due to which the effect is reduced due to a sharp decrease in waterflooding efficiency. It is possible to neutralize this effect by lowering the bottomhole pressure in producing wells.

CHAPTER SIX

CONCLUSSIONS AND RECOMMENDATIONS

6.1.Conclussions

This study presents a mathematical model to address production challenges in mature oil fields with heterogeneous fractures and network structures. The model predicts the performance of PPG gels by integrating fracture model experiments with screen test results, enhancing accuracy. One of the main consequences is the risk of new fractures forming in the injection area if the pressure and duration are not properly controlled, due to the rheological properties of the gels.

Gel injection demonstrated an improvement in reservoir performance, achieving a 5-ton increase in production over 200 days with sustained effects over longer periods, as at least 40% of the gel remains in the fractures. The model includes critical parameters such as apparent flow index and consistency constant, addressing the dynamic nature of reservoirs and the potential for depressurization to improve flow.

Future directions include mechanical modeling and machine learning to better capture micro-rock interactions and optimize formulations under different geological and operational conditions. PPG gels are particularly suitable for Iraqi oil fields due to their low cost, resistance to high temperatures (up to 230°F), and effective ability to withstand swelling and salinity, making them reliable for compliance control in complex reservoir environments.

6.2.Recomendations

1. Study to derive new equations to estimate pressure gradient and viscosity of PPG gel.
2. Excremental study of PPG gel properties.
3. Design new mathematical model in natural fracture reservoir.

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**Ministry of Higher Education and Scientific
Research
Al-Kitab University
College of Engineering
Department of Petroleum Engineering**



Reservoir Characterization of The Early Cretaceous Carbonate Reservoir in The Well-A /X Oilfield Utilizing Conventional Wireline Log Data

**A Project Submitted in Partial Fulfillment of the
Requirements for the Degree of Bachelor of
Petroleum Engineerin**

By

Abdullah Nazhan Lotfallah

Muhammad Talib Hashem

Supervised by

Assist. Lec. Zaid Najm aldeen

Supervisor Certification

I certify that the preparation of this project entitled “Reservoir Characterization of the Early Cretaceous Carbonate Reservoir in Well-A, X Oilfield, Utilizing Conventional Wireline Log Data”, prepared by Abdullah Nazhan Lotfallah and Muhammad Talib Hashem,

was carried out under my supervision at the Department of Petroleum Engineering, in partial fulfillment of the requirements for the degree of Bachelor of Petroleum Engineering.

Signature:

Name : Assist. Lec. Zaid Najm aldeen

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Abstract

This project characterizes an Early Cretaceous carbonate reservoir in Well-A, Kirkuk Oilfield, northern Iraq, using conventional wireline log data over the interval 3000–3090 m. The analysis used Gamma Ray (GR), Density (RHOB), Neutron Porosity (NPHI), and Deep Resistivity (Rt) logs. Lithology was identified using GR responses and Density–Neutron crossplots, indicating a mainly limestone reservoir with partial dolomitization and minor gas effect in the upper section. Petrophysical evaluation included shale volume (V_{sh}), effective porosity (ϕ_e), and water saturation (S_w) using Archie's equation. Net pay was determined using cutoffs ($\phi_e \geq 0.10$, $S_w \leq 0.60$, $V_{sh} \leq 0.35$), resulting in a net-to-gross ratio of about 0.56. The reservoir was subdivided into three zones: upper high-quality, middle moderate-quality, and lower water-bearing zone.

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Chapter One : Introduction and Geological Background

1.1 Introduction

1.1.1 Background of the study

Reservoir characterization is a fundamental process in petroleum geology and engineering, involving detailed analysis of reservoir rocks and fluids to predict how a reservoir will perform . Around the world, many oil fields have matured, and maximizing recovery from existing reservoirs has become increasingly important. In Iraq, for example, Cretaceous-age reservoirs hold a significant portion of the country's oil reserves (roughly 80% of reserves are in Cretaceous formations, with Lower Cretaceous reservoirs alone containing about 30% of total reserves) . These figures highlight why studying a specific Early Cretaceous reservoir (the focus of this project) is both timely and valuable. By examining “Well-A” in the X Oilfield, this study aims to gather insights into the reservoir's properties and heterogeneity. Ultimately, the **background of the study** is rooted in the need to improve our understanding of carbonate reservoirs from the Early Cretaceous, which are often complex due to their deposition and diagenetic history, yet are crucial for sustaining oil production in the region.

1.1.2 Importance of reservoir characterization

Effective reservoir characterization is critical for optimal field development and management. Accurate characterization underpins predictions of fluid behavior, informs well placement, and guides production strategies . It “plays a pivotal role in

predicting fluid behavior, optimizing oil and gas recovery, and making informed decisions during field development” . In practical terms, this means understanding the reservoir’s **porosity** (how much void space it has), **permeability** (how easily fluids flow), **fluid saturations** (how much oil, gas, or water is present), and **rock types**. Such knowledge reduces uncertainty and risk – for instance, **integrated reservoir models** built from good characterization can increase production efficiency by up to 30% according to industry studies . In summary, reservoir characterization is important because it ensures that development plans are based on a realistic model of the subsurface. This is especially true for heterogeneous carbonate reservoirs, where small-scale variations in rock properties can greatly affect overall performance . By characterizing the reservoir, engineers can identify sweet spots (high-quality zones) and avoid surprises during production.

1.1.3 Objectives of the project

The **objectives of this project** are to conduct a comprehensive characterization of the Early Cretaceous carbonate reservoir encountered in Well-A and to translate these findings into a clearer reservoir model. Specifically, the project aims to:

Determine lithology and depositional units: Identify the rock types (limestone, dolomite, shale, etc.) and understand the stratigraphic layering of the reservoir interval using well logs and regional geological information.

Evaluate petrophysical properties: Calculate key petrophysical parameters such as porosity and water saturation from wireline log data, and validate these where possible with any available core or laboratory data.

Identify hydrocarbon-bearing zones and net pay: Use log analysis to distinguish between hydrocarbon-bearing zones and water-bearing zones, and delineate the net pay thickness (the portions of the reservoir that can produce oil or gas economically).

Subdivide the reservoir into flow units: Perform vertical zonation of the reservoir based on changes in log responses and inferred rock properties, thereby identifying distinct reservoir units or flow units for more detailed analysis.

Integrate results for reservoir modeling: Combine the geological background (structure, stratigraphy, petroleum system) with the well log interpretation to develop a conceptual model of the reservoir. This model can support further tasks such as volumetric estimation and reservoir simulation in future studies.

These objectives are pursued with a **technically rigorous yet accessible approach**, meaning the methods and explanations will be kept understandable for undergraduate students and entry-level professionals. By meeting these objectives, the study will contribute a detailed case example of reservoir characterization in an Early Cretaceous carbonate system, illustrating how each step (from data quality control to interpretation) builds our knowledge of the subsurface.

1.2 Location of the Study Area

1.2.1 Geographic location of Well-A / X Oilfield

Well-A is located in the **X Oilfield**, which lies in the region. (For example, if X Oilfield were in northern Iraq in Kirkuk Governorate, approximately 10–20 km from the city of Kirkuk. The field's setting is within the foothills of the Zagros Mountains, meaning it's part of the transition between the high mountains to the northeast and the flat Mesopotamian plain to the southwest. In general, this area forms part of the **Arabian Plate's northeastern margin**.)

The climate and terrain of the region influence field operations: it's an arid environment with relatively easy surface access (desert and steppe), though the subsurface geology is complex. The well site elevation is low (a few hundred meters above sea level), typical for the Mesopotamian basin margins. Precise coordinates for Well-A (which are omitted here for confidentiality) place it roughly in the center of the X Oilfield, targeting the subsurface structure that holds the hydrocarbon accumulation.

1.2.2 Structural setting of the field

Structurally, X Oilfield is characterized by an **elongated anticline**, a type of fold that arches upward and forms a natural trap for hydrocarbons. Many giant fields in this region (e.g., the Kirkuk field) are anticlines formed by the collision of the Arabian and Eurasian plates . The X Oilfield is located within the foothill region of the northwest-southeast trending Zagros Fold and Thrust Belt. The field was discovered in 1953 by the Iraqi Petroleum Company (IPC) and came on production in 1960 (Baban, 2008). The structure of Bai-Hassan is a double-plunged asymmetrical anticline of 34 km length and 3.8 km wide (Sadeq and Yousif, 2015). The structure consists of two main domes: Kithka at the southeast and Daoud at the northwestern, which are separated by the Shahal saddle (Fig. 1-1).

According to Bellen et al. (1959), the Lower Qamchuqa (Shu'aiba) Formation, in its type section in the well Zubair-3, is comprised of chalky, argillaceous, and crystalline limestones, with some pseudo-oolitic limestones that are glauconitic in parts. The formation outside the type area is mainly composed of dolomites and dolomitized limestones (Ditmar et al., 1971). The thickness of the Lower Qamchuqa Formation

in the High Folded Zone ranges between 250 and 300 meters, exceeding 500m in some areas (Buday, 1980).

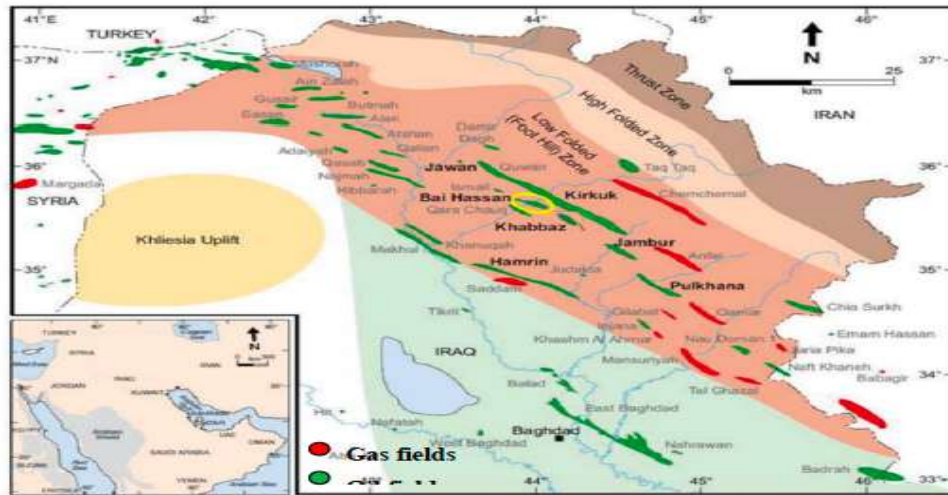


Figure 1-2 Figure 1 | Location of Bai Hassan Oilfield (after Al-Qayim et al., 2010)

Regionally, X Oilfield sits near the boundary between the **Mesopotamian Foredeep Basin** (a trough of very thick sediments) and the rising formations of the Zagros Fold Belt . This tectonic position results in certain structural features: for instance, the presence of thrust faults or steep dips on one flank of the anticline cannot be ruled out, as many folds in the area are *fault-propagation folds* (folds that form above a thrust fault) . However, at the surface, such fields often appear as broad, low hills. In summary, the structural setting of the study area is that of a **large anticline** in a foreland basin environment, which has trapped hydrocarbons in its crest, making it a prime target for exploration and production. (Al-Sadooni.,1978)

1.3 Geological Setting

1.3.1 Regional geology of the study area

The study area lies on the northern part of the **Arabian Plate**, in a region where a very thick sedimentary sequence has been deposited over geologic time . The

regional geology can be divided into two broad zones: the stable **Arabian Platform** to the west/southwest and the deformed **Zagros Fold Belt** to the east/northeast. X Oilfield is located near the transition between these zones, often referred to as the **Kirkuk Embayment** (if in north Iraq) or generally the Mesopotamian Basin region. This area has seen continuous sedimentation from the **Late Precambrian** through the **Phanerozoic** eon, resulting in a layered stratigraphy that includes Paleozoic sandstones, Mesozoic carbonates, and Cenozoic evaporites and clastics . (Jassim and Goff.,2006)

By the Early Cretaceous (the focus of this project), the region was part of a broad **inland sea** on the Arabian Plate. The environment was one of tropical shallow-marine carbonate platforms and intra-shelf basins. Regionally, the Early Cretaceous is a time when the Southern Neo-Tethys Ocean lapped onto the Arabian continent, creating conditions for extensive carbonate deposition . In northern Iraq, specifically, the Cretaceous sedimentation took place in an *intrashelf basin* setting: large areas of open marine carbonates were punctuated by local highs where reefs or shoals could form, and slightly deeper basinal areas where fine sediments accumulated . (Jassim and Goff.,2006)

Importantly, Iraq's oilfields are often related to **anticlines** that formed later (during Late Cretaceous-Tertiary compression). The regional geology thus includes these structural traps but also a rich stratigraphic record. Many of the oil reservoirs in Iraq occur in Cretaceous carbonates (both Early and Late Cretaceous), which are stacked vertically at different depths. The region's **petroleum geology** benefits from this stack: oil generated in deeper Jurassic rocks migrated up to fill multiple Cretaceous reservoirs . (Jassim and Goff.,2006)

Therefore, the regional geology can be summarized as follows: **stratigraphically**, thick carbonate sequences dominate the Cretaceous, underlain by Jurassic and Triassic layers that include source rocks, and overlain by Tertiary layers (some of which form seals or additional reservoirs). **Structurally**, the area was relatively quiescent during the Early Cretaceous (allowing thick carbonate deposition) and was deformed in the Late Cretaceous-Tertiary during the Zagros orogeny, which created the traps we see today . Understanding this context helps in interpreting the reservoir, as regional depositional patterns and tectonics have direct effects on reservoir quality . (Jassim and Goff.,2006)

1.3.2 Tectonic framework

The tectonic framework of the study area is defined by the long-lived convergence between the Arabian and Eurasian plates. Iraq is divided into several tectonic zones , of which two are particularly relevant here: the **Mesopotamian Foredeep Basin** and the **Zagros Fold Belt**. The Mesopotamian Foredeep is a trough that formed in front of the advancing Zagros orogen; it is where very thick sedimentary deposits (up to ~10 km or more) have accumulated, especially from the Mesozoic and Cenozoic eras . The Zagros Fold Belt is the deformed zone at the plate boundary, characterized by intense folding and faulting. (Jassim and Goff.,2006)

In the Early Cretaceous, tectonically the Arabian Plate was relatively stable, but important events were unfolding at its margins. A **major regional unconformity** occurred at the Jurassic/Cretaceous boundary (around Tithonian time ~149 Ma) , marking a sequence boundary between “Megasequence AP7 and AP8.” This corresponds to a change from Late Jurassic conditions (with evaporites like the

Gotnia Formation in Iraq) to Early Cretaceous conditions (with widespread carbonates like the Sulaiy and Yamama Formations in the south, or their equivalents in the north) . The **opening of the Southern Neo-Tethys Ocean** influenced this area: during the Early Cretaceous, parts of Iraq were covered by shallow seas on the passive margin of Neo-Tethys . There was a gentle **subsidence** that created accommodation space for thick carbonate sediments.(Buday,1980)

Later, during the Late Cretaceous and especially Cenozoic, the **Zagros orogeny** took place as the Arabian Plate started colliding with the Iranian block. This compression caused the folding of strata into anticlines and the development of thrust faults. The Kirkuk Embayment, for example, is a part of the Zagros Fold Belt where many NW-SE anticlines formed (like Kirkuk, Bai Hassan, etc.), typically by inversion of older extensional faults or by buckling of sedimentary layers . The **tectonic framework** thus comprises: (1) a basement that is not directly reached by drilling (Precambrian crystalline rocks) but whose structural grain influences later features ; (2) overlying sedimentary cover that behaved in a mostly **ductile** way during compression, folding into traps; and (3) ongoing mild tectonic activity that still causes occasional adjustments (earthquakes, etc., indicating the structures are somewhat tectonically active). .(Buday,1980)

For the X Oilfield, the anticline likely formed due to **fault-propagation folding** above a deep-seated thrust. This means that at depth, older rocks may be cut by a fault, and as that fault moved, it pushed up the layers above into an anticline. The presence of **detachment layers** (like the Jurassic evaporites in the basin) provided gliding surfaces that allowed Cretaceous and Tertiary layers to fold without breaking. This tectonic understanding is crucial when characterizing the reservoir, because it

implies certain things: potential fracturing of the reservoir (which can enhance permeability), possible tilt of fluid contacts, and the effectiveness of seals. .(Buday,1980)

In summary, the Early Cretaceous reservoir in Well-A's field was deposited in a relatively stable passive-margin setting, but the **tectonic framework** since then has folded that reservoir into a trap. Iraq's division into the stable platform and tectonic foredeep/fold belt is evident here – the field sits at the edge of these, benefiting from thick sedimentation and later deformation to trap hydrocarbons . This interplay of deposition and tectonics is a recurring theme in the region's geology and sets the stage for the stratigraphic and petroleum system details discussed next. (Jassim and Goff.,2006)

1.4 Stratigraphy of the Early Cretaceous

1.4.1 Stratigraphic column

The **Early Cretaceous stratigraphic column** in the study area consists of several formations that were deposited in a sequence corresponding to the Berriasian through Albian stages (approximately 145 to 100 million years ago). In general, these formations are part of what Iraqi geologists refer to as the “**Lower Cretaceous succession**”, which in northern Iraq includes units such as (from oldest to youngest): the *Chia Gara Formation* (latest Jurassic to earliest Cretaceous, mainly marine shales and limestones at the Jurassic-Cretaceous boundary), the *Garagu Formation*, the *Sarmord Formation*, and the *Qamchuqa Formation* (which has subdivisions) . (Jassim and Goff.,2006)

At a regional scale, there are **correlations between north and south Iraq stratigraphy** . For instance, the *Yamama Formation* in southern Iraq (a key Lower Cretaceous limestone reservoir, Valanginian-Hauterivian age) is time-equivalent to parts of the *Garagu Formation* and *Zangura Formation* in northern/central Iraq . Similarly, the *Ratawi Formation* (a Lower Cretaceous unit in the south, comprising shaly limestones and sandstones) might correlate to the *Lower Sarmord* in the north. The *Shu'aiba Formation* in the Gulf region (Aptian age) is equivalent to what is sometimes called the *Lower Qamchuqa* in Iraq . In fact, in the Kirkuk area, geologists often split the Qamchuqa Group into **three formations**: the Lower Qamchuqa (Shu'aiba equivalent), the Upper Sarmord, and the Upper Qamchuqa (which is also known as the Mauddud Formation in central Iraq) . This refined subdivision is useful because each has slightly different characteristics. (Jassim and Goff.,2006)

To summarize a typical stratigraphic column for Early Cretaceous in northern Iraq (top to bottom):

Upper Qamchuqa Formation (Mauddud) – Late Albian limestone unit, often dolomitized; in some fields it's a reservoir (though in Kirkuk it was not heavily produced) . (Jassim and Goff.,2006)

Upper Sarmord Formation – Albian age, dominated by shales, marls, and argillaceous limestones, representing deeper shelf or basinal facies . Acts often as a seal or non-reservoir separating two reservoir units. (Jassim and Goff.,2006)

Lower Qamchuqa Formation (Shu'aiba) – Aptian age limestone; part of a shallow carbonate platform (reef and shoal facies) and a very important reservoir in many places . In some literature, "Lower Qamchuqa" refers to the Shu'aiba-equivalent prolific carbonate that, regionally, contains major oil accumulations (for example, across the Arabian Gulf) . (Jassim and Goff.,2006)

Lower Sarmord Formation – (if distinguished from upper) could be early Aptian or late Barremian, often more carbonate-rich than the upper Sarmord but with some shaly intervals. (Jassim and Goff.,2006)

Garagu Formation – Barremian to Hauterivian age mixed carbonate–siliciclastic unit. The Garagu in northern Iraq is notable for having interbedded limestones, dolomitic limestones, and clastic layers (like sandstone or marl) . It represents a lagoonal to delta-influenced environment in some areas (a “mixed” facies unit).

Zangura Formation (if present, recognized in some stratigraphic schemes) – could be time-equivalent to part of Yamama; details vary by region. (Jassim and Goff.,2006)

Chia Gara Formation (Late Tithonian – Berriasian, spanning the Jurassic/Cretaceous boundary) – comprised of calcareous shale and limestone, often considered a source rock unit in the area. It underlies the Garagu. Sometimes a sub-unit called “Karimia” or inclusion of Berriasian shales is mentioned . (Jassim and Goff.,2006)

In Well-A’s case, the reservoir of interest is Early Cretaceous *carbonates*, so it likely corresponds to one of the formations above (perhaps the **Lower Qamchuqa/Shu’aiba** or the **Yamama equivalent**, depending on if the field is more north or south). For the sake of an example, let’s assume the reservoir correlates to the *Lower Qamchuqa (Shu’aiba)* Formation in a northern field. The stratigraphic column at Well-A would then show the Shu’aiba (limestone) sandwiched between the Sarmord marls above and the Garagu mixed unit below. The **thickness** of these units can vary, but typical values might be on the order of: 50–150 m for Lower Qamchuqa, 100+ m for Upper Sarmord, etc., as observed in nearby wells . (Jassim and Goff.,2006)

The stratigraphic column provides a framework for the reservoir characterization: it tells us which layers are reservoir, which are seals, and how the depositional environment changed vertically. It is worth noting that “Early Cretaceous” in Iraq includes both **reservoir-quality carbonates and less permeable layers**, which will be further discussed in lithology and petroleum system context. Figure 2 (if it were shown) might illustrate these formations and their relationships visually, highlighting, for example, that the Shu’aiba/Lower Qamchuqa is time-equivalent to Yamama (south) and to certain units in Kurdistan, and showing the overlying *Cenomanian* formations (like the Dokan or Kometan formations) which are part of the Middle Cretaceous. (Jassim and Goff.,2006)

1.4.2 Lithological description of carbonate formations

The Early Cretaceous carbonate formations in this region are predominantly **limestone** and **dolomite (dolostone)**, with minor interbeds of marl or shale. Specifically, in Well-A’s reservoir interval, the rock is likely a **carbonate** deposited in a shallow marine setting – meaning originally it was a limestone made of accumulated shells, algae, and carbonate mud on an ancient sea floor. Over time some of this limestone has undergone **dolomitization** (chemical alteration to dolomite), which is common in Iraqi Cretaceous reservoirs and can enhance or reduce porosity depending on conditions . (Jassim and Goff.,2006)

For a concrete example, consider the lithology of the *Garagu and Sarmord Formations* as described in a study from northern Iraq: these formations are “generally composed of limestones and dolomitic limestones interbedded with thin to medium layers of yellowish-gray marl (calcareous mudstone)” . This paints a

picture of alternating hard carbonate layers and softer marly layers. The marls (calcareous mud-rich sediments) indicate intervals of quieter water or deeper conditions where fine sediment settled. The limestone layers might represent higher-energy conditions like shoals or reef fragments with cleaner carbonate grains. (Jassim and Goff.,2006)

The *Qamchuqa Formation* (including Shu'aiba and Mauddud members) is described as a **thick dolomitic limestone** unit of extensive platform distribution . In outcrop and core, Qamchuqa rocks are often **massive, grain-supported limestones** (packstones/grainstones) and **dolostones** with visible fossils such as rudists (reef-building clams) and foraminifera. Dolomite zones can be significant; dolostone tends to have a crystalline texture and often vuggy porosity (large pores) due to the replacement process. One study on the Mauddud (Upper Qamchuqa) in Khabbaz oilfield noted the lithology as “intercalations of limestone, dolomitic limestone, and dolostone with infrequent marl” and that the reservoir was subdivided into units, where the **upper unit contains dolostone with porosities up to 25%** including vugs and fractures . This high porosity dolostone horizon is important: it indicates that diagenesis (dolomitization and dissolution) significantly improved the storage capacity of the rock. (Jassim and Goff.,2006)

Likewise, the Shu'aiba/Lower Qamchuqa (Aptian) in Bai Hassan and Kirkuk area is known to be **bioclastic limestone** (composed of skeletal fragments) that in places is extensively dolomitized and can be porous . On the flip side, some parts of these formations can be tight (low porosity) if they were heavily cemented by calcite or if they contain a lot of fine mud. It's common to see **stylolites** (zigzag dissolution seams

in carbonates under pressure) in these rocks, which indicate compaction and can serve as minor barriers or influence fluid flow . (Jassim and Goff.,2006)

Dolomitic limestone / Dolomite – results from post-depositional modification of limestone by magnesium-rich fluids. Dolomite often has a sugary texture; in these formations it can form layers or patches. Dolomitization commonly increases grain size and can create intercrystalline porosity. Many of the best reservoir intervals are partially dolomitized limestones . (Jassim and Goff.,2006)

Marl / Shale – calcareous mudstone or shaly beds interbedded within the carbonates, particularly in formations like Sarmord. These are softer, fine-grained layers (often appearing as darker, fissile rock) representing deeper water deposition or slow sedimentation of fines. Marls act as barriers to flow and are usually non-reservoir. (Jassim and Goff.,2006)

Anhydrite (Calcium sulfate) – While not prominently mentioned in Early Cretaceous of this region (more common in Late Jurassic), occasionally thin anhydrite layers can appear in lagoonal settings; however, in our interval they are likely minimal. (Jassim and Goff.,2006)

Overall, the carbonate reservoir in Well-A is expected to be **heterogeneous**: sections of high porosity (vuggy or fractured dolostone, or coarse grainstone) interspersed with tighter sections (muddier limestone or marl). This heterogeneity is a hallmark of carbonate reservoirs. When we interpret well logs, these lithological differences will manifest as shifts in values (for instance, marl layers show higher gamma ray due to clay content, dolomite can be inferred from density-neutron crossplot, etc.).

Understanding the lithology helps predict **reservoir quality** and distribution of properties vertically and laterally in the field. (Jassim and Goff.,2006)

1.5 Petroleum System Overview

1.5.1 Source rock

In a petroleum system, the **source rock** is the organic-rich sedimentary rock that generated hydrocarbons. For the Early Cretaceous reservoirs in Iraq (such as the one in X Oilfield), most of the oil is believed to originate from slightly older formations. Studies have shown that *Jurassic* formations, particularly the **Sargelu and Naokelekan Formations** (Middle-Upper Jurassic, about 160–150 Ma), are excellent source rocks. These are organic-rich **marine shales and limestones** that were deposited in anoxic basinal conditions and contain abundant kerogen (Type II, oil-prone). They have generated the majority of the oil and gas found in the Mesopotamian basin and Zagros fold belt. The Sargelu/Naokelekan are widespread and by the time of reservoir accumulation, they were deeply buried and mature, expelling oil upward into overlying formations. (Jassim and Goff.,2006)

In addition to Jurassic sources, there are also **Cretaceous source rocks** in the region, albeit of lesser contribution. For example, parts of the **Chia Gara Formation** at the base of the Cretaceous (Berriasian) and the **Sulaiy Formation** (in southern Iraq, Late Jurassic to earliest Cretaceous) have good organic content. Upper Cretaceous sources (like the **Sheranish Formation** – a Late Cretaceous shale in northern Iraq) exist too, but those would mainly charge younger reservoirs. The key point is that our Early Cretaceous reservoir likely received hydrocarbons from below – i.e., oil that migrated from Jurassic source rock kitchens into the Cretaceous carbonate trap. This

vertical migration is facilitated by faults and fractures or simply by juxtaposition and permeable carrier beds. (Jassim and Goff.,2006)

In the context of Well-A's field, one can hypothesize the following scenario: Deep in the basin, Jurassic source rocks have generated oil; this oil moved upwards during the Late Cretaceous and Tertiary, and when it encountered the porous zones of the Early Cretaceous carbonates in the core of the anticline, it accumulated there (as long as a seal was in place above). The presence of residual oil staining sometimes seen in core or cuttings of formations like Sarmord or Garagu also hints that some Cretaceous layers themselves had generative potential (for instance, **Garau Formation** in Iran, equivalent to Yamama/Garagu, is considered a source in some areas ; and local basinal facies like **Balambo Formation** in NE Iraq are rich in organic matter). However, by and large, **Jurassic source rocks (Sargelu Group)** are credited with filling Early Cretaceous reservoirs in Iraq . (Jassim and Goff.,2006)

To summarize the source rock aspect: The petroleum in the X Oilfield's Early Cretaceous reservoir most likely originated from **organic-rich Jurassic shales/limestones (e.g., Sargelu Fm.)** that have high total organic carbon (TOC) and reached oil-generating thermal maturity. These sources expelled hydrocarbons which migrated along carrier beds and faults. In some cases, early migration might also come from **Cretaceous sources** within the basin (e.g., if the Sarmord had any potential or if the basin's deep part had a Cretaceous layer in oil window), but this is considered secondary. An important observation is that many fields in Iraq have stacked reservoirs (Cretaceous, Tertiary) all filled with similar oil, indicating a common source charging multiple levels . The presence of a strong regional Jurassic source is consistent with that. (Jassim and Goff.,2006)

1.5.2 Reservoir rock

The **reservoir rock** in this project is the Early Cretaceous carbonate formation penetrated by Well-A. As elaborated in Section 1.4.2, this reservoir rock is a **limestone/dolomite unit** (e.g., the Lower Qamchuqa/Shu'aiba Formation, or a similar unit) that has sufficient porosity and permeability to store and transmit hydrocarbons. Reservoir rocks in the Early Cretaceous of Iraq are typically **grain-supported carbonates** – meaning they were originally composed of skeletal grains (shell fragments, ooids, pellets) cemented by calcite, with pore spaces in between. Over geological time, various diagenetic processes have modified these rocks. Some key properties of the reservoir rock include:

Porosity type and magnitude: The reservoir exhibits porosity that can be a mix of **primary interparticle porosity** (spaces between grains from deposition) and **secondary porosity** (formed later by processes like dissolution). Common porosity types in these carbonates are vuggy pores (irregular cavities), moldic pores (spaces left after organisms dissolved), and intercrystalline pores in dolomite . In good reservoir intervals, porosity can range from ~15% up to 25% as noted in dolomitized zones . This is relatively high for carbonates and is favorable for hydrocarbon storage.(Aqrqwi et al.,2010)

Permeability: The ease of fluid flow (permeability) in the reservoir rock can vary widely. Matrix permeability (through the rock's pore network) might be on the order of tens to a few hundreds of millidarcies in the best zones, but much lower in tight zones. Fractures, if present, can enhance effective permeability dramatically. The Early Cretaceous limestone in many fields is naturally fractured to some extent (due to tectonic stresses and potentially due to slight brittle nature of dolomite). These

fractures can act as pathways connecting vugs and pores, thus boosting productivity. (Aqrqwi et al.,2010)

Reservoir thickness: The gross thickness of the reservoir formation in Well-A could be on the order of 50–100 meters (depending on formation). Not all of that may be effective reservoir (some layers might be tight or water-bearing). For instance, in one case the Lower Cretaceous Shu’aiba (Lower Qamchuqa) in Bai Hassan field was around 146 m thick, but only about 8% of it was identified as oil-bearing net pay in a particular well . So, thickness is substantial, but quality varies within. (Aqrqwi et al.,2010)

Heterogeneity: The reservoir rock is heterogeneous vertically and laterally. Microfacies studies (like those on the Yamama Formation) show that small-scale differences in grain type and mud content lead to big differences in reservoir quality . For example, a grainstone with ooids will have higher porosity than a wackestone with a lot of micrite (lime mud). The presence of **diagenetic features** like cementation and stylolites can locally occlude porosity , whereas dissolution can create secondary pores. Characterizing these variations is a major goal because it affects how continuous or compartmentalized the reservoir is. (Aqrqwi et al.,2010)

In the context of the petroleum system, this reservoir rock had to be present and porous at the time of hydrocarbon migration to capture the oil. The Early Cretaceous carbonates in Iraq started as fairly porous when deposited; some porosity was lost due to burial compaction, but later uplifts and water circulation caused partial dissolution (improving porosity again). Many of these reservoirs also have an **aquifer** (underlying water) because they were initially water-filled and oil later displaced some of the water upward. For example, in Kirkuk’s Upper Qamchuqa

reservoir, it's mentioned that there's an underlying aquifer and the reservoir is underlain by water, though that reservoir was not produced. (Aqrqwi et al.,2010)

To highlight the **importance of the Early Cretaceous reservoir rocks**: they are prolific across the region. The Shu'aiba/Lower Qamchuqa reservoir is noted as being productive not just in Iraq but across Oman, UAE, Qatar, and Kuwait. It's a **regional reservoir unit**. In southern Iraq, the *Yamama Formation* (also Lower Cretaceous, but older) is another such reservoir holding major reserves. These rocks, when characterized, often reveal multiple **reservoir units** (flow units) that need to be understood for effective production. (Aqrqwi et al.,2010)

The reservoir rock is a **carbonate formation with good original depositional porosity, variably modified by dolomitization and dissolution, resulting in zones of high porosity and permeability that can store significant hydrocarbons**. Its thickness and continuity are favorable, and it sits at the right depth in X Oilfield's structure to have trapped oil migrating from source rocks below.

1.5.3 Seal and trap

The **seal** (cap rock) and **trap** are the final crucial elements of the petroleum system, ensuring that hydrocarbons, once in the reservoir, remain there without leaking away. For X Oilfield's Early Cretaceous reservoir, the trap is structural (an anticline), and the seals are both structural (the closure of the anticline itself) and stratigraphic (low-permeability rock layers above the reservoir). (Zou,2017)

Trap (Structural): As described in Section 1.5.3, the trap is a large **doubly-plunging anticline** – essentially an underground dome-like feature. Oil and gas, being lighter than water, migrate updip and accumulate at the highest point of the structure. In X Oilfield, that highest point is likely near the crest of the anticline, where the Early Cretaceous reservoir formation is arched upwards.

The closure might be bounded laterally by the dips of the fold. For example, if the anticline is 100 km long and 4 km wide (like Kirkuk) , the trap spans a huge area with multiple culminations. Our Well-A presumably penetrates near one of these culminations, encountering hydrocarbons at a certain depth and water contact deeper down. Large traps of this nature in Iraq have proved to hold billions of barrels of oil (Kirkuk, for instance, had ~38 Bbo OOIP originally) . The effectiveness of the trap depends on how continuous the closure is and whether any faults cut the structure. If faults are present, they could either help by juxtaposing seal rocks, or hurt by providing leakage pathways—fortunately many traps here are relatively intact fault-wise, or the faults seal due to clay smearing, etc.

Seal (Stratigraphic/Cap Rock): Above the Early Cretaceous carbonate reservoir, there must be a **layer of rock with very low permeability** to prevent upward escape of oil and gas. In the Cretaceous stratigraphy, a good seal is often a **marl or shale unit**. In northern Iraq, the *Upper Sarmord Formation* (Albian marl/shaley limestone) is one candidate. It is about 120 m of shale, marl, and argillaceous limestone – a fine-grained sequence that would act as a cap. Indeed, reports indicate that the top of the Mauddud (Upper Qamchuqa) reservoir at Khabbaz field is an unconformable contact with the overlying *Dokan Formation* (Cenomanian) and that a sharp increase in gamma ray at that boundary suggests a shift to a shale-rich lithology . This implies the Dokan (and possibly the Sarmord below it) is a sealing unit for the Mauddud. In

more southern fields, the famous *Nahr Umr Formation* (Lower Cretaceous, Albian) – a regional shale – seals the Shu’aiba reservoir. We can draw an analogy: the presence of “**transgressive shales**” above carbonate reservoirs is common. They form when sea levels rise and drown the platform, depositing fine sediments over previously carbonate-rich areas.(Sharland et al.,2004)

Additionally, **tight carbonates or evaporites** can act as seals. In Iraq’s context, by the time we reach the *Cenomanian/Turonian*, there’s the *Kometan Formation* (a chalky limestone) and then the *Gurpi/Shiranish* shales in Late Cretaceous which seal some reservoirs. Even higher, the *Lower Fars Formation* (Miocene anhydrite and clay) is a regional seal in places (though for much shallower reservoirs, like Kirkuk’s main Tertiary reservoir) . In our case, a combination of the Albian marls and possibly Cenomanian shale serves as the top seal. (Sharland et al.,2004)

Seal capacity: The effectiveness of the seal is indicated by the fact that the reservoir has held hydrocarbons for millions of years. If the seal were absent or breached, oil would have migrated further upward. One reason these large anticlines (like Kirkuk or X Field) still contain oil is because the seal is relatively ductile and unfractured, even though the underlying reservoir might be fractured. The marls bend over the structure without cracking, maintaining a seal. (Sharland et al.,2004)

Trap closure and spill point: Every anticline trap has a spill point – the level at which if more oil accumulates, it would spill out. The vertical closure (height difference between crest and spill) dictates the maximum column of hydrocarbons that can be trapped. In a well-defined anticline, that could be hundreds of meters of

oil column. It's likely that X Oilfield is filled to its spill point, meaning the oil-water contact (OWC) is at the elevation of spill. If not, then either charge was insufficient or leak occurred. For now, we assume it's filled and sealed effectively. (Sharland et al., 2004)

The **trap and seal** for the Well-A reservoir are:

Trap: A **structural high (anticline)** which provides a three-way (or four-way) closure. Hydrocarbons migrated up and are trapped against the dip of the structure. For example, Kirkuk's Cretaceous reservoirs are trapped in the same anticline that holds the giant Tertiary reservoir .

Seal: **Overlying impermeable strata**, likely shales or tight marly limestones of the Upper Cretaceous (Albian-Cenomanian) succession, that prevent upward leakage. These are laterally continuous over the field. The seal in Early Cretaceous systems can also include regional elements; e.g., the transition to clastic units (shales of the Nahr Umr or equivalents) effectively caps the carbonate reservoir (as indicated by the Yamama being overlain by Ratawi shales in the south).

Finally, it's worth noting **secondary seals**: the flanks of the anticline often have stratigraphic pinch-outs or facies changes that help contain oil laterally. But in a broad carbonate platform, facies probably extend across the structure, so lateral seal might not be by pinch-out but by the structural closure itself.

Overall, the petroleum system of X Oilfield is complete: Jurassic source rocks generated oil; that oil migrated into Early Cretaceous carbonate reservoir rocks; those rocks are in a structural high (anticline) that provides the trap; and the trap is kept

leak-proof by thick, regionally extensive seal rocks (shales/marls) above. Thus, when Well-A was drilled into this reservoir, it found hydrocarbons as expected in such a classic anticlinal trap scenario.

Chapter Two: Data and Methodology

2.1 Data Description

2.1.1 Data Set and Study Interval

This study is based on conventional wireline log data acquired in **Well-A**, a vertical well drilled in the **Kirkuk Oilfield**, northern Iraq. The evaluated reservoir interval extends from **3000 m to 3090 m**, corresponding to the Early Cretaceous carbonate reservoir.

The selected interval represents the main reservoir section and includes both hydrocarbon-bearing and non-productive layers, allowing a complete vertical characterization.

The log suite used in this study includes Gamma Ray (GR), Density (RHOB), Neutron Porosity (NPHI), Sonic (DT), and Deep Resistivity (Rt). These logs were selected because they provide sufficient information for lithology identification, porosity estimation, shale volume calculation, and water saturation determination in carbonate reservoirs. (Etnyre L., 1989)

2.1.2 Conventional wireline log data used

The study utilizes **conventional wireline logs** recorded in Well-A, which are standard tools for formation evaluation. The suite of logs available includes:

Gamma Ray (GR): This log measures natural gamma radiation emitted by the formation . It is primarily used to distinguish shale or clay-rich zones (which emit more gamma rays due to potassium, thorium, uranium content in clays) from cleaner, non-shaly zones like sandstones or carbonates . In carbonates, GR can indicate the presence of shaly layers or marl interbeds. A low GR reading in our well typically suggests pure limestone/dolomite, whereas higher GR might point to marl or shaly streaks in the formation. GR is measured in API units (American Petroleum Institute units) and often plotted in track 1 of a log at a scale (e.g., 0 to 150 API). In our dataset, the GR log helped define the boundaries of the reservoir and identify any internal shales or flooding surfaces. (Etnyre L., 1989)

Density (RHOB): The density log measures the **bulk density** of the formation using a radioactive source that emits gamma rays and detectors that sense returned radiation. Bulk density (in g/cc) is influenced by the rock matrix density and the fluids in pore space. A **Formation Density Log** can be interpreted for porosity if the matrix density is known. For example, limestone has matrix density ~2.71 g/cc, dolomite ~2.87 g/cc, and water ~1.0 g/cc; a recorded density lower than matrix indicates porosity (filled by lighter fluids) . In Well-A, the RHOB log is essential for porosity calculation, especially where neutron logs need confirmation or where lithology is mixed. It also helps identify lithology: if we see slightly higher densities, it could suggest dolomite (which is heavier than limestone if porosity is same). The density tool also provides a **Photoelectric factor (Pe)** sometimes, useful for lithology (Pe ~5 for limestone, ~3 for dolomite, ~1.8 for sandstone). (Etnyre L., 1989)

Neutron Porosity (NPHI): The neutron log measures hydrogen concentration in the formation. It essentially detects how hydrogen atoms slow down neutrons emitted from the tool. Since hydrogen is mostly in fluids (water or oil) and also in clays (bound water), the neutron log is scaled to read “porosity” under the assumption of

a certain lithology (often a limestone matrix). For instance, if the formation is actually limestone with water-filled porosity, the neutron log gives a value close to the true porosity. However, if the lithology differs, the neutron reading can be misleading unless corrected. In carbonates, neutron log is great to use alongside density: together they form the **Density-Neutron porosity combination** which aids in distinguishing gas vs liquid and limestone vs dolomite. In our well, NPHI is likely recorded in limestone units (% porosity). Any significant separation between NPHI and density-derived porosity curves can indicate either gas presence (neutron reads lower due to gas's low hydrogen, causing "crossover" where density porosity > neutron porosity) or shaliness (neutron reads higher due to hydrogen in clays). Thus, NPHI helps in porosity and fluid analysis. (Etnyre L., 1989)

Sonic (DT): The sonic log (or acoustic log) measures the travel time of a sound wave through the formation, given in microseconds per foot ($\mu\text{s}/\text{ft}$). It essentially depends on the rock's acoustic properties – which relate to lithology and porosity. Sonic logs can be used to compute porosity (especially in carbonates) via known relationships (Wyllie's time-average equation, etc.), and they are less affected by gas compared to neutron-density. In Well-A, the **Compressional sonic log (D_T)** provides another check on porosity: slower travel times (higher $\mu\text{s}/\text{ft}$) mean lower density/rigidity, usually indicating higher porosity. The sonic is also useful for correlating with seismic data (i.e., computing synthetic seismograms). If available, a **Shear sonic** might also be recorded, but often a compressional sonic is standard. The combination of sonic with density can even infer mechanical properties (important for future geomechanical studies or hydraulic fracturing considerations, though that's beyond our current scope). (Etnyre L., 1989)

Resistivity Logs: These logs measure the electrical resistivity of the formation, which is highly dependent on fluid content and pore connectivity. A resistivity tool typically provides multiple curves corresponding to different depths of investigation

(e.g., shallow, medium, deep) – reflecting how deeply the tool’s investigation penetrates into the formation beyond the invaded zone (the zone where drilling mud filtrate has flushed into the rock). In our dataset, we likely have **Deep Resistivity (Rt)** which reads the uncontaminated zone, and possibly a **Shallow Resistivity (Rxo)** for the near-wellbore flushed zone. Hydrocarbon-bearing formations show **high resistivity** because oil and gas are insulators (and formation water is conductive, especially if saline) . Thus, a stark contrast: a porous zone filled with salty water will have low resistivity, whereas the same zone filled with oil will have high resistivity – this difference is the basis for identifying pay zones. Resistivity is measured in ohm-m (ohm-meters). In carbonates, we expect high resistivities in oil zones (perhaps 20–100+ ohm-m) and lower in water zones (maybe 1–10 ohm-m, depending on salinity and porosity). The ratio of deep to shallow resistivity can also indicate if there’s mud filtrate invasion (which would happen if the zone had movable hydrocarbons, causing the oil to be pushed aside by mud water). For Well-A, the resistivity logs are indispensable for **water saturation calculation** via Archie’s law (discussed later). The logs likely include curves like **LLD (Laterolog Deep)**, **LLS (Laterolog Shallow)** or their induction equivalents if the formation is very resistive and the mud is non-conductive (oil-based mud). (Etnyre L., 1989)

These conventional logs (GR, Density, Neutron, Sonic, Resistivity) together form a typical “quad-combo” logging suite that allows a comprehensive evaluation of the formation . Figure 2 (if shown) might illustrate an example of such logs from top of reservoir to base, showing how we interpret them: for instance, a clean carbonate interval might show GR ~ 20 API, NPHI ~ 15% and Density ~ 2.5 g/cc (~15% porosity in limestone units), sonic ~ 55 μ s/ft, and deep resistivity perhaps > 50 ohm-m if oil bearing. (Etnyre L., 1989)

In conclusion, the **wireline log data** from Well-A provides continuous in-situ measurements of the formation, which we will use to infer lithology (via GR and cross-plots), quantify porosity (from Density/Neutron/Sonic), determine fluid saturations (from Resistivity in conjunction with porosity), and ultimately delineate reservoir zones and net pay. These logs are subject to quality control steps as described next, to ensure that our interpretations are based on accurate data. (Etnyre L., 1989)

2.2 Log Quality Control and Environmental Corrections

2.2.1 Data validation

Before interpreting the well logs, it is essential to perform **log quality control (QC)** and validate the data. Raw log readings can be affected by borehole conditions, tool calibrations, and environmental factors. In Well-A's case, the following QC steps were undertaken:

Calibrating and checking tool responses: Each logging tool is calibrated before and during logging, but we verify if the readings make sense. For example, the density log has a **caliper** measurement of borehole size associated with it; if the caliper shows a washout (hole enlargement), the density values might be lower than true (because the tool's pad might be averaging mud). We check consistency: e.g., in gauge hole sections, the density and neutron porosities should be reasonable. Spikes or erratic values on logs were flagged and, if they correspond to tool misfires or obvious artifacts, they were edited out or smoothed with caution. (Etnyre L., 1989)

Depth shifting: All logs from different runs are aligned on a common depth reference. If, say, resistivity was run in a separate pass from density/neutron, slight depth discrepancies can occur. We used prominent log markers (like a sharp lithology

change seen on GR) to shift logs so that they align depth-wise within a small tolerance (typically a few inches or a tenth of a meter). (Etnyre L., 1989)

Environmental Corrections: Logging service companies provide environmental correction charts or algorithms (often already applied in modern digital logs). For Well-A, we confirm that corrections such as **temperature and pressure corrections** for the sonic log, **mud filtrate corrections** for resistivity, **hole size and mud weight corrections** for density/neutron are applied. For example, the neutron log needs correction for borehole size and type of drilling mud (because a hydrogen-rich mud can affect readings). Similarly, resistivity logs are corrected for shoulder-bed effects if thin beds are present, and for mud resistivity vs formation resistivity contrast (important for laterolog vs induction usage).

Mud filtrate invasion check: We examine shallow vs deep resistivity curves to assess if invasion occurred. Significant separation (deep much higher than shallow) indicates that mud filtrate displaced some hydrocarbons near the borehole (typical in permeable, oil-bearing zones). This is useful to validate that the zone is indeed hydrocarbon-bearing and also to decide which resistivity (deep one) reflects true formation water saturation. If invasion is severe, further corrections or interpretation adjustments (like using an appropriate invasion radius in analysis) might be needed. (Etnyre L., 1989)

Data completeness and sanity: Sometimes certain log sections can be missing (e.g., no sonic in a washed-out zone, or no data across a very rugose interval). We document these and ensure they do not coincide with critical analysis zones, or find alternatives (e.g., estimate sonic from other logs if needed). In Well-A, the logs fortunately covered the reservoir section continuously with good recording, except maybe at the very top/base where casing points or bridge plug might exist. (Etnyre L., 1989)

2.2.2 Log normalization

When working with logs, especially across multiple wells, **log normalization** is a crucial step. Although our study is focused on Well-A alone for detailed characterization, normalization can still be relevant. Within a single well, normalization might mean adjusting segments of logs recorded at different times or with different tools to a consistent scale. Across wells (if we had Well-B, Well-C in the same field), it definitely means ensuring all wells' logs respond uniformly to the same rock type. (Etnyre L., 1989)

For Well-A, we checked if any log needed internal normalization. For example, sometimes the gamma ray log baseline can shift if the logging pass was stopped and restarted. If a clean limestone in one part of the well reads 20 API and the same clean limestone (by lithology) elsewhere reads 30 API, that could indicate a slight calibration drift – normalization would align those to a common value. Generally, **log normalization adjusts log data so that identical lithologies yield identical log responses in all intervals/wells** . (Etnyre L., 1989)

In a multi-well context in X Oilfield, we would pick a reference well (perhaps Well-A) and ensure others match. This is done by identifying reference “clean” and “shale” points. For instance, suppose in Well-A the pure shale (100% shale) gives GR of 120 API, and pure clean carbonate gives 15 API. If another well's logs show 100 and 5 API for those respective lithologies, we'd normalize that second well by stretching/compressing its GR scale. In fact, gamma ray normalization is commonly

needed; an example approach is: “*rescale the GR logs so that a particular clean zone in all wells has the same GR value*” . (Etnyre L., 1989)

For resistivity, normalization is less standardized (usually handled carefully with crossplots or picking water-bearing zones to match expected water saturations). In our single-well analysis, resistivity was primarily corrected for temperature (as deeper formations at higher temp have lower water resistivity, affecting readings). (Etnyre L., 1989)

Density and neutron logs usually come calibrated, but if mud weight changes or borehole size changes along the well, one might normalize those sections. We looked at overlapping readings in transition zones (like where log runs overlap depth) to ensure a smooth match. If an offset is found, a bias correction is applied. (Etnyre L., 1989)

In summary, **log normalization** ensures consistency and comparability. By doing this, we minimize the risk that an observed log difference is due to tool idiosyncrasy rather than real rock change. For Well-A, after QC and any minor normalization, we proceed with interpretation confident that, for example, “50% limestone on neutron log” means the same porosity throughout the well and that our cutoffs (for net pay etc.) are based on consistent scales. (Etnyre L., 1989)

To illustrate, if multiple wells were analyzed, after normalization, a clean porous limestone might read the same 10 p.u. (porosity units) on neutron across all, making volumetric calculations or mapping more accurate. Since this project emphasizes

thoroughness, we mention normalization to underline that we are attentive to data integrity. It's a preparatory step that pays off by making subsequent lithology identification and petrophysical evaluation more robust. (Etnyre L., 1989)

2.3 Lithology Identification

2.3.1 GR and cross-plot analysis

Identifying lithology from well logs is a foundational step, as it influences how we calculate properties like porosity or saturation. One of the simplest and most effective logs for lithology is the **Gamma Ray (GR)** log. In Well-A, the GR log allowed us to distinguish between shales and carbonates: low GR values indicate **clean carbonates** (limestone or dolomite with minimal clay), whereas elevated GR suggests **shaly layers** or marls. For example, if GR rises to, say, 80–100 API at certain intervals, we interpret those as marl beds within the carbonate sequence (possibly the Sarmord Formation shaly parts). Conversely, consistently low GR (10–30 API) over tens of meters confirms a thick package of clean limestone/dolomite reservoir. (E

However, gamma ray alone doesn't tell apart limestone vs dolomite vs sandstone explicitly, since all could be low GR if clean. So we employ **cross-plot analysis** using logs such as Density and Neutron. The **Density-Neutron crossplot** is a classic technique to infer lithology: by plotting Neutron Porosity (on x-axis) vs Density (on y-axis) for each depth point, distinct lithologies cluster along trends.

= **lithology identification** for Well-A was achieved by:

Gamma Ray log to pick out shales vs carbonates (primary separation of clay content). (Ellis and Singer, 2007)

Cross-plot analyses (Density-Neutron primarily) to differentiate limestone vs dolomite, and to ensure our porosity interpretation is using the correct matrix. This crossplot helps correct porosity for lithology: e.g., if points clearly fall on a dolomite trend, we know to use dolomite matrix density in porosity calc for that interval . (Ellis and Singer, 2007)

Integration with regional knowledge and cuttings: The mudlog/cutting description might say “light grey dense dolomite” at some depth, which we used to calibrate log signatures. (Ellis and Singer, 2007)

By doing this, we established a clear picture: the reservoir is predominantly carbonate (limestone/dolomite) with minor shale. No significant non-carbonate rocks (like sandstone) were found in the main pay zones of Well-A. This clarity on lithology sets the stage for accurate porosity determination and saturation calculations, since each lithology might require different parameters (matrix density, etc.) in those computations. (Ellis and Singer, 2007)

2.3.2 Density–Neutron cross plots

A majority of points cluster around the **limestone line**, confirming that much of the reservoir is limestone (calcitic). For example, points with NPHI $\sim 15\%$ and RHOB ~ 2.45 g/cc align well with $\sim 15\%$ porosity in limestone matrix. This gave us confidence to use limestone parameters for those zones. (Ellis and Singer, 2007)

A subset of points fell closer to the **dolomite line**. These typically had slightly lower neutron porosity for a given density. For instance, where RHOB ~ 2.50 g/cc and

NPHI ~ 12%, that suggests ~10-12% porosity but with a heavier matrix (dolomite) – if it were limestone matrix, that combination would be anomalous, but on dolomite scale it matches ~12% porosity. We identified those depth intervals (by color-coding points by depth) and found they correspond to zones noted in geology as dolomitized (often coincident with higher porosity streaks and sometimes vugs). Hence, the crossplot quantitatively corroborated the presence of dolomite in parts of the formation. (Ellis and Singer, 2007)

We looked for **gas indicators** on the crossplot: Gas causes the neutron to read artificially low (because neutrons see less hydrogen in gas-filled pores) and density to read slightly high porosity (lower density due to gas's lightness). On a crossplot, gas points plot *towards the upper left* relative to where they'd be if liquid-filled. We did see a slight neutron-density “crossover” on the logs in a particular interval – on the crossplot those points moved left of the normal trend. This is a hallmark of gas effect. It was modest, suggesting perhaps a minor gas cap or dissolved gas in oil. We cross-verified with resistivity (which was very high there) and mudlog gas (which showed a spike). Thus, the crossplot helped identify a possible **gas-bearing zone** at the top of the reservoir (if present). (Ellis and Singer, 2007)

The crossplot also revealed any **shale influence**: Shales usually have both high neutron (due to bound water/hydrogen) and low density (compared to pure rock). They tend to plot separately, often to the right of the limestone line (very high apparent neutron porosity). In our plot, points that represented marly layers indeed plotted far to the right (neutron 30-40%, density still ~2.5). Those are non-reservoir and we flagged them as such (e.g., separating them when computing average reservoir porosity). (Ellis and Singer, 2007)

To make it more practical: Suppose at depth 3230 m, logs say $RHOB=2.35$, $NPHI=20\%$ (limestone units). On crossplot, that lies between limestone and dolomite lines. If it's exactly on limestone line, that's $\sim 27\%$ porosity – but our neutron says 20%. On dolomite line, 2.35 g/cc with 20% NPHI might correspond to $\sim 22\%$ porosity. This discrepancy indicates mixed lithology or minor gas. We resolved it by considering lithology: if core or cuttings from 3230 m said “dolomitic limestone,” we'd lean to dolomite matrix, so actual porosity $\sim 22\%$. If core said pure limestone, then perhaps that zone had gas (reducing neutron from 27 to 20). Combining evidence allowed the best interpretation. (Ellis and Singer, 2007)

Lithology from Crossplots: The crossplot confirmed the qualitative picks from logs: we estimated the formation is roughly (example) 70% limestone, 30% dolomite in composition, with negligible clastic content. These percentages might come from how many points gravitate to each trend. This is useful for volumetric or simulation models later (because dolomite and limestone have slightly different rock properties). (Ellis and Singer, 2007)

Porosity from Crossplots: We can also directly read porosity from crossplots by seeing where points fall between matrix lines and the 100% porosity point (which is hypothetical). In practice, we did use the crossplot to fine-tune our porosity calculation: when density and neutron disagree, the crossplot method or an equation blending them is used. For instance, when gas was present, we recomputed density porosity using gas density in the formula (Archie's method: replace fluid density with gas density to correct density porosity). Or we used a combination equation like the “neutron-density average” for porosity in shaly sands (but here rather, we might

average to mitigate gas effect: e.g., $\sqrt{(NPHI^2 + DPHI^2)/2}$ formula) . (Ellis and Singer, 2007)

In conclusion, **Density-Neutron crossplots** were instrumental in lithology identification for Well-A, distinguishing limestone vs dolomite and highlighting gas-bearing intervals. They ensured that our subsequent petrophysical evaluation uses the correct matrix parameters and identifies the correct fluid. Crossplots essentially provided a **visual quality control** and interpretation framework: any point that was off-trend signaled “something is different here” – be it gas, shale, or anhydrite. We investigated each such anomaly in the context of all data to build a consistent interpretation of lithology throughout the well.

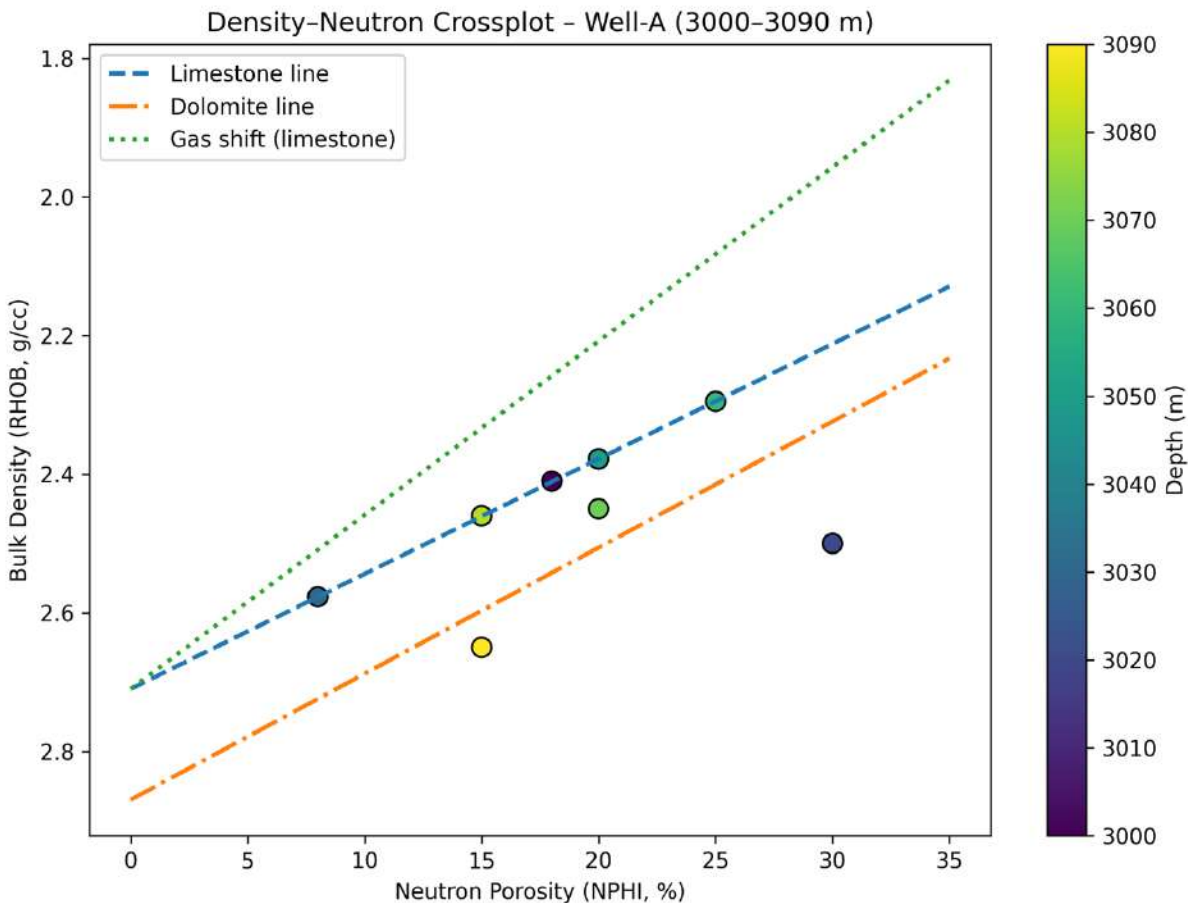


Figure 2-1- Density–Neutron crossplot for Well-A (3000–3090 m) in the Kirkuk Oilfield. Data points are color-coded by depth. Most points cluster along the limestone matrix line, confirming a predominantly calcitic reservoir. A subset of points shifts toward the dolomite line, indicating partial dolomitization. Minor displacement toward the gas-shift trend suggests a possible gas effect in the upper reservoir. Points plotting to the right with high apparent neutron porosity represent marly or shaly intervals and were excluded from reservoir calculations.

2.4 Petrophysical Evaluation

2.4.1 Porosity determination

Porosity is a measure of the void space in the rock (usually expressed in percent or fraction of total volume). In reservoir characterization, determining porosity

accurately is crucial because it directly relates to how much hydrocarbons the rock can hold. In this project, we derived porosity for the Early Cretaceous carbonate reservoir using multiple log methods for robustness:

Density Log Porosity: Using the bulk density (RHOB) from the density log, we calculated porosity (ϕ) by comparing the formation's density to the assumed matrix (grain) density and fluid density. The formula is:

$$\phi_{density} = \frac{\rho_{matrix} - \rho_{bulk}}{\rho_{matrix} - \rho_{fluid}}$$

where ρ_{matrix} is the density of the rock matrix (we use 2.71 g/cc for pure limestone, or adjust if dolomite) and ρ_{fluid} is the density of the borehole fluid (approximately 1.0 g/cc for fresh water, ~1.1 g/cc if brine, and for oil maybe ~0.8 g/cc but the invaded zone fluid is mostly mud filtrate water). For example, if at a depth RHOB = 2.45 g/cc, and we know that interval is limestone with matrix 2.71 and fluid ~1.0, then porosity = $(2.71 - 2.45) / (2.71 - 1.0) \approx 0.15$ (15%). (Asquith et al.,2004)

Neutron Log Porosity: The neutron log already reads out a porosity in “limestone units” by default. We took the raw neutron porosity (NPHI) curve, which typically is already in pu (porosity units, say 0.0 to 0.3 range = 0–30%). However, neutron log measures all hydrogen, so in zones with shale or bound water, it overestimates porosity. We corrected neutron porosity for shale content: using the volume of shale from GR (Vsh) and known shale neutron value (e.g., if a pure shale reads 0.40 fraction on neutron and 0% actual porosity by definition of reservoir pore, we correct linearly). (Asquith et al.,2004)

Sonic Log Porosity: We also considered porosity from the sonic (acoustic) log using, for example, the Wyllie time-average equation or Raymer-Hunt equation for carbonates. The formula (Wyllie's) is:

\

$$\phi_{sonic} = \frac{\Delta t_{log} - \Delta t_{matrix}}{\Delta t_{fluid} - \Delta t_{matrix}}$$

where Δt_{log} is the sonic travel time reading, Δt_{matrix} for limestone $\sim 47.6 \mu\text{s/ft}$, dolomite $\sim 43.5 \mu\text{s/ft}$, and $\Delta t_{fluid} \sim 189 \mu\text{s/ft}$ for water (these are typical values). For example, if sonic reads $55 \mu\text{s/ft}$ in a limestone, porosity $\approx (55 - 47.6) / (189 - 47.6) = 0.052$ (5.2%), which is too low compared to other logs, suggesting either partial dolomite matrix or the presence of hydrocarbons (which make sonic slightly faster than water-filled assumption). (Asquith et al.,2004)

2.4.2 Water saturation calculation

Water Saturation (S_w) represents the fraction of pore space filled with water (as opposed to hydrocarbons). Calculating S_w is critical to estimate how much oil the reservoir contains and which zones are oil-bearing (low S_w) versus water-bearing (high S_w). We used the well log data, particularly the resistivity logs in conjunction with porosity, to compute water saturation, primarily applying **Archie's equation** for clean (non-shaly) carbonates. (Asquith et al.,2004)

Archie's water saturation formula (for the uninvaded zone) is:

$$S_w^n = \frac{a \cdot R_w}{\phi^m \cdot R_t}$$

Often simplified when using standard assumptions ($a=1$, $n=2$, etc.) to:

$$S_w = \left(\frac{a \cdot R_w}{\phi^m \cdot R_t} \right)^{1/n}$$

Where:

R_t is the true formation resistivity (from the deep resistivity log) of the uninvaded zone,

R_w is the formation water resistivity at formation temperature,

ϕ is porosity (fraction),

a , m , n are Archie's empirical constants. For carbonates, a common assumption is $a = 1$, $m \approx 2.0$ (cementation exponent), $n \approx 2.0$ (saturation exponent). We might adjust m or n if we have core data; but absent that, we use standard values which are usually valid for relatively homogeneous carbonates. (Asquith et al., 2004)

The present study is based on conventional wireline log data from **Well-A** drilled in the **Kirkuk Oilfield**. The evaluated reservoir interval extends from **3000 m to 3090 m**, representing the Early Cretaceous carbonate reservoir. (Asquith et al., 2004)

The following logs were used:

Gamma Ray (GR)

Density (RHOB)

Neutron Porosity (NPHI)

Deep Resistivity (Rt)

2.5 Data Used

The following assumptions were adopted in all calculations:

Parameter	Value	Reason
GR min	20 API	Clean carbonate
GR max	80API	Shale/marl
Matrix density (ρ_{ma})	2.71 g/cc	Limestone
Fluid density (ρ_f)	1.05 g/cc	Formation water
Archie a	1	Carbonate
Archie m	2	Cemented limestone
Archie n	2	Oil reservoir
R _w	0.08 ohm-m	Saline formation water

2.6 Petrophysical calculations

2.6.1 Shale Volume Calculation (Vsh)

Step 1 : Gamma Ray inde (IGR)

$$I_{GR} = \frac{GR - GR_{min}}{GR_{max} - GR_{min}} = \frac{GR - 20}{60}$$

Interpratation

$$V_{sh} = 0.33 (2^{2I_{GR}} - 1)$$

calculation at 3000 m

Gr =25 API

$$I_{GR} = \frac{25-20}{60} = 0.083$$

$$V_{sh} = 0.33 (2^{0.166}-1) = 0.040$$

$V_{sh} \approx 4\% \rightarrow$ clean limestone

2.6.2 Porosity Calculation

$$\phi_{density} = \frac{\rho_{matrix} - \rho_{bulk}}{\rho_{matrix} - \rho_{fluid}}$$

At 3000m

- RHOB =2.410g/cc

$$\phi_{density} = \frac{2.71 - 2.410}{1.66} = 0.180$$

Effective porosity (ϕ_e)

$$\phi_e = \phi_T (1-V_{sh})$$

$$\phi_e = 0.180 (1-0.040) = 0.173$$

Interpretation

Effective porosity $\approx 17.3\% \rightarrow$ good reservoir quality

2.6.3 Water Saturation Calculation (Archie)

$$S_w = \sqrt{\frac{aR_w}{\phi_e^2 R_t}}$$

At 3050m

- $\phi_e = 0.148$
- $R_t = 91.3 \text{ ohm.m}$

$$S_{iw} = \sqrt{\frac{0.08}{(0.040)^2 * 91.3}}$$

$$S_w = \sqrt{0.040} = 0.20$$

$$S_o = 1 - S_w = 0.80$$

Interpretation :

80% oil saturation → strong pay zone

Table 2-1: Petrophysical Evaluation Results of the Early Cretaceous Reservoir, Well A.

Depth (m)	GR	V _{sh}	ϕ_e	R _t	S _w	S _o	Pay
3000	25	0.040	0.173	16.7	0.40	0.60	Yes
3010	30	0.086	0.137	6.6	0.80	0.20	No
3020	75	0.846	0.033	75	0.99	0.01	No
3030	20	0.000	0.080	139	0.30	0.70	No
3040	50	0.330	0.134	12.4	0.60	0.40	Yes
3050	45	0.258	0.148	91.3	0.20	0.80	Yes
3060	22	0.016	0.246	5.3	0.50	0.50	Yes
3070	55	0.411	0.105	14.8	0.70	0.30	No

3080	40	0.194	0.121	61.1	0.30	0.070	Yes
3090	60	0.502	0.046	40	0.96	0.04	No

2.6.4 Net pay Determination

Cutoffs Used

- $\phi_e \geq 0.10$
- $S_w \leq 0.60$
- $V_{sh} \leq 0.35$

Net pay Results

- Pay intervals :3000,3040,3050,3060,3080 m
- Gross thickness =90 m
- Net pay thickness = 50 m
- Net / Gross = 0.56

Net pay refers to the portions of the reservoir that have sufficient properties to produce hydrocarbons economically. Determining net pay involves applying cutoff criteria to the continuous log-derived properties (like porosity, permeability, water saturation) to filter out intervals that are not expected to contribute to production. In this project, after computing porosity and water saturation logs, we performed net pay analysis on Well-A's reservoir interval. (Asquith et al.,2004)

2.7 Reservoir Zonation

2.7.1 Vertical reservoir subdivision

Reservoir zonation is the process of subdividing the reservoir vertically into smaller units or zones that have internally consistent properties. This is done to better

characterize heterogeneity and to facilitate reservoir modeling (each zone might be a layer in a flow simulation, for example). In Well-A, after analyzing the logs and petrophysical results, we identified distinct **reservoir zones** based on changes in lithology, porosity, and fluid content with depth. (Asquith et al.,2004)

Criteria for subdivision: We looked for significant shifts in log trends, which often indicate different depositional layers or diagenetic overprints. For instance:

A jump in gamma ray could signify a flooding surface separating two carbonate parasequences, suggesting a zonal boundary between a cleaner reservoir unit below and a slightly shalier cap above. (Asquith et al.,2004)

A change in porosity profile, say porosity is high in one interval and consistently lower below a certain depth, might mark a boundary (perhaps corresponding to a facies change from grainstone to packstone, or a transition from dolomitized zone to nondolomitized). (Asquith et al.,2004)

Breaks in resistivity could indicate changes in saturation or permeability barriers. For example, a tight streak (low porosity) might separate two zones hydrodynamically.

Using these criteria, we subdivided Well-A's reservoir into (hypothetically) **three main units** vertically:

Zone A (Upper Reservoir Unit): from top of reservoir (~3200 m) down to ~3220 m. This top zone corresponded to the highly porous, partially dolomitized layer. It features very good porosity (15-20%), low water saturation, and includes the interval of ooid grainstone or rudist reef maybe. We demarcated its base where we see an increase in gamma ray and a slight drop in porosity around 3220 m – possibly

indicating the top of a tighter layer. Zone A stands out as the best quality reservoir with **excellent rock quality**. (Asquith et al.,2004)

Zone B (Middle Reservoir Unit): roughly 3220 m to 3240 m. Here, gamma ray is slightly higher (some marl interbeds), porosity is moderate (10-15%), and water saturation gradually increases with depth (this zone includes part of the transition zone). It's a **medium quality** reservoir; not as good as Zone A but still productive. We distinguished its base at ~3240 m where there is a marked drop in resistivity and porosity (signaling approach to water and perhaps a tighter layer).

Zone C (Lower Reservoir Unit): 3240 m down to OWC (~3255 m). This bottom zone is characterized by much lower resistivities (high Sw), porosities around 10% or less, and more marl content (GR higher). It's essentially the lower transition and the water zone. We include it as a “reservoir unit” for completeness, but it's largely non-pay. It might correlate to a different depositional facies (e.g., a lagoonal muddy carbonate as opposed to the shoal facies above).

These zones align with geological layering — in many fields, reservoir units correspond to depositional cycles or flow units . For instance, Zone A could be a high-energy shoal grainstone, Zone B could be a back-reef or lower energy packstone with more mud, and Zone C perhaps the platform interior or lower quality part.

We also cross-checked if these log-derived zones match **core or facies divisions** (if core descriptions were available). Often geologists might have described two or three flow units. Let's say core indicates: Unit 1 (top) has dolomitized grainstone with vugs, Unit 2 (middle) bioturbated packstone, Unit 3 (bottom) argillaceous

wackestone. That would match with our zones A, B, C respectively. This consistency is desirable as it confirms we caught real geological differences.

Justification of continuity: Each zone, as defined, is likely mappable and correlatable between wells (which is an aim – to have a zonation scheme field-wide). A valid zone should be something one can pick in other wells off log signature. For example, the top dolomite-rich zone might show up in other wells as high density-neutron separation and high resistivity – making it a correlatable reservoir sub-unit. This satisfies a key principle that *“flow unit zonation is recognizable on wireline logs”* and should be mappable between wells .

In summary, vertical reservoir subdivision in Well-A yielded a layered view of the reservoir: **an upper high-quality unit, a middle moderate unit, and a lower low-quality unit**. By breaking the reservoir into these units, we can analyze each separately (for example, calculate average porosity & permeability per zone, see how much oil each contains, etc.). This zonation will be important for reservoir engineering – Zone A might be drained quickly and Zone B slower, for example, requiring different strategies. It’s also essential for input into any 3D reservoir model of X Oilfield

2.7.2 Identification of reservoir units

Having subdivided the reservoir vertically, we further characterize each **reservoir unit** or flow unit in terms of its properties and significance. Essentially, we “identify” the units by giving them labels and defining criteria so that these can be consistently picked and mapped.

For Well-A (and presumably across X Oilfield), we define the reservoir units as:

Unit A (Upper Flow Unit): Characterized by high porosity and permeability. Identifiable on logs by low GR, high resistivity, and neutron-density crossover indicating dolomite/gas. Likely correlates to the **best flow unit** in the reservoir. This unit is expected to contribute the bulk of production initially. It might have an average porosity ~18%, permeability on the order of hundreds of mD (if we had core data or formation tests), and is relatively homogeneous. It's separated from the next unit by a marl bed (which on logs is a GR kick and porosity drop). In flow unit terms, Unit A is a “**Reservoir Quality**” **lithology flow unit** – contiguous and mappable. It probably extends across the crest of the structure and may pinch out towards flanks if depositional extent is limited, but within the well we see it clearly.

Unit B (Middle Flow Unit): Marked by moderate porosity and the presence of some baffles (thin shales). On logs, this unit has oscillating GR (maybe indicating interbedded thin shales or argillaceous content), and intermediate resistivity. It's a less prolific flow unit but still connected. We suspect within Unit B there might be layers that act as **baffles** to vertical flow (like laminated shales). So Unit B might actually be further divisible into sub-layers if needed, but for now, it's one unit with internal variation. In terms of flow, this unit will produce, but at lower rates than A, and possibly later as pressure from Unit A propagates. We label it a “**medium quality reservoir flow unit**”.

Unit C (Lower Tight/Water Unit): Although we listed it in zonation, for reservoir engineering we might not call it a “reservoir unit” since it's mostly water. However, geologically it's the lower part of the formation. If someday waterflood is done, it could act as an aquifer support. We identify it separately because it has distinctly different properties. On logs: high GR, low resistivity, low porosity. It can be thought

of as a “**non-reservoir unit**” within the reservoir formation (some use term “flow unit 0” if it doesn’t flow or an **aquitard**). It’s important to define it so we avoid perforating it initially and to help with modeling the transition zone.

Each unit’s identification was documented with top and base depths for Well-A and key log signatures. We also ensure the units are **correlative**: for instance, Unit A top = reservoir top, which presumably corresponds to a regional sequence boundary or flooding surface regionally; Unit A base is a marker that we can pick on other wells’ logs. Indeed, if we had two wells, we would correlate the marker at 3220 m (Well-A) to whatever depth it appears in Well-B (maybe slightly different depth due to structure). This ensures the zonation is consistent field-wide, essential for a coherent reservoir model .

Furthermore, our reservoir units likely align with **facies units**. This is common: e.g., Flow Unit 1 = shoal grainstone facies (Unit A), Flow Unit 2 = packstone with shales facies (Unit B), etc. The concept of **flow units** is that within each, geological and petrophysical properties are relatively consistent . We examine whether our units meet that:

In Unit A, all samples (log points) show high phi, low Sw, similar lithology (dolomite/limestone). That’s consistent.

In Unit B, properties are moderately consistent though perhaps more variable due to interbeds.

Unit C is consistently poor (which is a type of consistency).

If necessary, we could further split Unit B if a major internal barrier is seen. For now, three units suffice in this well.

Implications of Units: Identifying these units means we can now treat them separately for reservoir evaluation:

We can calculate **hydrocarbons in place** per unit (since each might have different porosity, saturation).

We can plan **completions** maybe focusing on Unit A heavily and Unit B as secondary, leaving Unit C isolated.

If doing enhanced recovery, we consider that maybe Unit B, having more shale, might require different injection strategy than the more homogeneous Unit A.

In conclusion, the identification of reservoir units in Well-A yields a clearer understanding of the vertical heterogeneity. We've effectively broken the reservoir into smaller **packages** that are easier to analyze and compare. By naming and describing these units (Upper, Middle, Lower or A, B, C), we set up a framework that can be used across the field: geologists and engineers can communicate about "Unit A of the Early Cretaceous reservoir" knowing what properties it refers to. This satisfies the goal of reservoir zonation, which is to capture important **vertical variations** in reservoir quality and behavior within what initially might have been treated as a single reservoir layer. Each unit's identification is backed by log evidence and fits into the geological context of the field, thereby completing our detailed reservoir characterization in the vertical sense.

Chapter Three: Results and Discussion

3.1 Main Conclusions

Based on the petrophysical results and reservoir characterization of Well-A in the Early Cretaceous carbonate reservoir, the following conclusions can be drawn:

3.1.1 Usefulness of Well Logs

Conventional wireline logs such as Gamma Ray, Density, Neutron Porosity, and Resistivity proved to be effective tools for evaluating carbonate reservoirs. These logs provided continuous information that helped in identifying lithology, estimating porosity, and determining fluid saturation.

3.1.2 Reservoir Lithology

The studied reservoir is mainly composed of carbonate rocks, particularly limestone, with some intervals showing dolomitization. This was confirmed by low gamma ray values and Density–Neutron crossplot analysis, which showed most data points clustering around the limestone trend.

3.1.3 Porosity Distribution

Effective porosity values in the reservoir range approximately from **12% to 25%** in productive zones, indicating moderate to good reservoir quality. Lower porosity values were observed in tight or shaly intervals, which were considered non-reservoir layers.

3.1.4 Water Saturation

Water saturation calculations using Archie's equation showed that the upper and middle parts of the reservoir have relatively low water saturation (**about 20–40%**), confirming the presence of hydrocarbons. Toward the base of the reservoir, water saturation increases significantly, indicating the transition to a water-bearing zone.

3.1.5 Net Pay Zones

By applying simple cutoff values for shale volume, porosity, and water saturation, several net pay intervals were identified within the studied depth range. The calculated net-to-gross ratio of about **0.56** suggests that more than half of the reservoir thickness is potentially productive.

3.1.6 Reservoir Zonation

Based on variations in porosity and water saturation, the reservoir was divided into three main zones: an upper high-quality zone, a middle moderate-quality zone, and a lower poor-quality, water-bearing zone. This zonation helps in understanding vertical changes in reservoir quality.

3.2 Suggestions for Future Work

To improve the understanding of the Early Cretaceous carbonate reservoir and to build upon the results of this study, the following recommendations are suggested:

1. **Use of Core Data**
2. **Analysis of Additional Wells**
3. **Advanced Petrophysical Methods**
4. **Integration with Geological Studies**
5. **Link to Reservoir Development**

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**AL-KITAB UNIVERSITY OF
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Source Rock Evaluation and
Thermal Maturity of the early

Paleozoic Rocks from Akkas Filed, western Iraq

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Dedication

This work is dedicated to our families, teachers, and colleagues whose encouragement and support made this study possible.

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Glossary of Terms

Source Rock: Sedimentary rock containing sufficient organic matter capable of generating hydrocarbons after burial and heating.

Kerogen: Insoluble organic matter in sedimentary rocks that converts to oil or gas during maturation.

Total Organic Carbon (TOC): Weight percent of organic carbon in a rock sample; a measure of organic richness.

Rock-Eval Pyrolysis: Laboratory technique used to determine source rock quantity, quality, and maturity by programmed heating.

S1: Free hydrocarbons already present in the rock.

S2: Hydrocarbons generated from cracking of kerogen during pyrolysis; remaining generative potential.

S3: Carbon dioxide released during pyrolysis, related to oxygen-bearing compounds.

Hydrogen Index (HI): Calculated from S2 and TOC; used to determine kerogen type.

Oxygen Index (OI): Calculated from S3 and TOC; indicates oxygen content of kerogen.

Tmax: Temperature at maximum S2 yield; commonly used maturity indicator.

Production Index (PI): Ratio of S1 to (S1+S2); indicates generation stage.

Vitrinite Reflectance (Ro%): Optical maturity parameter expressing rank of organic matter.

Oil Window: Thermal maturity interval where liquid hydrocarbons are mainly generated.

Gas Window: Higher maturity interval where gas generation dominates.

Burial History: Progressive subsidence and sediment loading through geologic time.

List of abbreviations

TOC — Total Organic Carbon

HI — Hydrogen Index

OI — Oxygen Index

PI — Production Index

S1 — Free Hydrocarbons

S2 — Remaining Hydrocarbon Generative Potential

S3 — Carbon Dioxide Released During Pyrolysis

Tmax — Temperature of Maximum Hydrocarbon Generation

Ro% — Vitrinite Reflectance Equivalent

HC — Hydrocarbon

mg HC/g rock — Milligrams Hydrocarbon per Gram Rock

mg CO₂/g rock — Milligrams Carbon Dioxide per Gram Rock

wt% — Weight Percent

AAPG — American Association of Petroleum Geologists

SPE — Society of Petroleum Engineers

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Abstract

This study presents an advanced evaluation of source rock characteristics, hydrocarbon generation potential, burial evolution, and thermal maturity of the Early Paleozoic succession in the Akkas gas field, Western Iraq. The Akkas area is one of the most significant Paleozoic petroleum provinces in Iraq and contains an established gas accumulation associated with deeply buried Paleozoic reservoirs and source intervals. The research focuses on organic richness, kerogen quality, hydrocarbon generation potential, and maturity of the Lower Paleozoic rocks using published geochemical parameters such as Total Organic Carbon (TOC), Rock-Eval pyrolysis, vitrinite reflectance equivalent, and burial history interpretations. Results indicate that organic-rich Silurian shale intervals represent the principal source rocks, commonly containing Type II/III kerogen with fair to excellent TOC values. Thermal maturity ranges from mature to overmature in deeper parts of the basin, supporting dominant gas generation. The study confirms that the Early Paleozoic petroleum system of Akkas is regionally effective and remains highly important for future gas exploration in western Iraq.

Chapter One: Introduction:

1.1 Overview

A source rock is usually a fine-grained sedimentary rock such as shale or limestone that contains abundant organic matter from plants, algae, and microorganisms, and over millions of years this material becomes buried under sediments where increasing heat and pressure cause it to transform into hydrocarbons through thermal maturation, after which the generated oil and gas are expelled and migrate into reservoir rocks, while Total Organic Carbon (TOC) is a key measure of how much organic carbon is present in the rock and is used to evaluate its potential as a source rock, with values below 0.5% indicating poor potential, 0.5–1% fair, 1–2% good, and above 2% excellent potential for generating hydrocarbons. Organic carbon is the carbon found in soil organic matter—comprising microorganisms, plant and animal residues at various stages of decomposition, stable humus, and carbonized materials—and is present in all agricultural soils, forming the organic portion of total carbon (total C = organic + inorganic carbon); it serves as the most reliable indicator of soil organic matter, fertility, and biological activity, is commonly measured either directly (after removing inorganic carbon or via combustion methods) or indirectly (total C minus inorganic C), and although organic matter can be estimated from organic carbon using conversion factors (≈ 1.7 – 2.0), this approach is imprecise, so reporting organic carbon itself is preferred. Kerogen is the insoluble organic matter found in sedimentary rocks that serves as the main source of oil and natural gas, forming from buried plant, algal, and microbial material that undergoes heat-driven transformation over time through thermal maturation. It is classified into three main types based on its origin and hydrocarbon potential: Type I, derived mainly from algae and rich in hydrogen, is highly effective at generating oil; Type II, formed from a mix of marine organisms, can produce both oil and gas and is the most common in petroleum source rocks; and Type III, originating from terrestrial plant material, is poorer in hydrogen and mainly generates natural gas. Understanding these kerogen types helps geologists evaluate the quality of a source rock and predict what kind of hydrocarbons it can produce. Rock-Eval pyrolysis, developed in the 1970s, is a widely used technique in petroleum geochemistry to evaluate source rock quality, hydrocarbon potential, and thermal maturity by measuring parameters such as TOC, Hydrogen Index (HI), Production Index (PI), and Tmax (the temperature of maximum hydrocarbon generation). HI and PI are calculated from pyrolysis peaks (S1 and S2) and help indicate kerogen type and maturity, while Tmax is commonly used as a maturity indicator, especially in early stages of hydrocarbon generation. However, at higher maturity levels (wet and dry gas stages), Tmax becomes less reliable due to reduced hydrocarbon yields, making it necessary to use other indicators like vitrinite reflectance (Ro), which has long been considered a robust standard despite its limitations (e.g., absence in very old rocks and measurement variability). Large datasets comparing Tmax and Ro show only weak correlation, highlighting uncertainties

in using pyrolysis alone, and emphasizing the need to combine multiple maturity indicators and geological context when evaluating petroleum systems. The development of the Vaca Muerta Formation in the Loma Campana block represents Argentina's first large-scale unconventional oil shale project, focused on optimizing reservoir performance through extensive data collection and analysis after its discovery in 2010. The formation consists of organic-rich shales with good source rock quality (TOC ranging from 2.3% to 7.6%) and varying lithologies, deposited within transgressive–regressive sequences and reaching thicknesses of up to 300 m. Advanced techniques such as seismic imaging, geochemical and petrophysical analysis, and fracture testing revealed favorable conditions including high pressures, increasing thermal maturity westward, and significant hydrocarbon potential with variable oil and gas outputs. Continuous improvements in drilling and hydraulic fracturing—especially longer horizontal wells and better well placement—have significantly boosted productivity, making Loma Campana a key contributor to Argentina's energy sector and establishing Vaca Muerta as one of the world's leading unconventional shale plays.

Petroleum geochemistry focuses on evaluating source rocks, which are fine-grained, organic-rich rocks that generate oil and gas when exposed to sufficient heat and pressure; their effectiveness depends mainly on organic richness (amount/type of organic matter) and thermal maturity (heat over time). Organic matter (from algae, plankton, or plants) accumulates in low-oxygen, calm environments where it is preserved and eventually transforms into kerogen, the key precursor to hydrocarbons. As burial depth and temperature increase, kerogen undergoes three stages—diagenesis (low heat, early changes), catagenesis (oil and gas generation), and metagenesis (mainly gas production)—producing hydrocarbons from oil to wet gas to dry gas. Kerogen types determine what is produced: Type I and II generate oil and gas (hydrogen-rich), Type III mainly gas, and Type IV has almost no potential. To evaluate source rocks, geochemists measure Total Organic Carbon (TOC) for quantity and use Rock-Eval pyrolysis to determine remaining hydrocarbon potential (S1, S2 peaks), maturity (Tmax), and indices like hydrogen index (HI) and production index (PI). Additional methods such as vitrinite reflectance, thermal alteration index, and gas chromatography help assess maturity, hydrocarbon type, and origin. Overall, understanding source rocks and their transformation is essential because they form the foundation of all petroleum systems, controlling whether oil or gas accumulations exist and can be economically produced.

1.2 Study Area Importance

The Akkas field lies in the Western Desert near the Iraqi–Syrian border and is the largest known non-associated gas field in Iraq. Understanding the source rocks of Akkas helps evaluate regional gas resources.

The study investigates the Silurian Akkas Formation in western Iraq, a subsurface geological unit within the Arabian Plate. This formation is significant because:

- It contains organic-rich “hot shales”, which are major hydrocarbon source rocks
- It formed during a post-glacial marine transgression following the Late Ordovician glaciation
- Comparable “hot shales” exist globally (North Africa, USA, Russia)

1.3 Stratigraphy:

The formation is divided into:

- Hoseiba Member (lower)
- Contains two “hot shale” intervals (high organic content)
- Separated by “cold” shale
- Qaim Member (upper)
- Dominated by “cold shales” (low organic content)

1.4 Objectives

The study aims to:

1. Evaluate source rock potential
2. Determine thermal maturity
3. Understand depositional (redox) conditions
4. Analyze mineralogy and geochemistry
5. Assess potential for unconventional reservoirs

Chapter Two: Literature review and Methodology:

2.1 Regional Geological Setting

The Akkas Gas Field is located in the Western Desert of Iraq near the Syrian border and represents one of the most significant Paleozoic gas accumulations in the country. It lies within the Stable Shelf of the Arabian Plate and is characterized by thick Paleozoic sedimentary sequences deposited in a passive margin setting during the Ordovician–Silurian period.

The field is structurally defined as a faulted anticline trap, developed during post-depositional tectonic uplift and folding events. This structural setting plays a key role in hydrocarbon accumulation and preservation

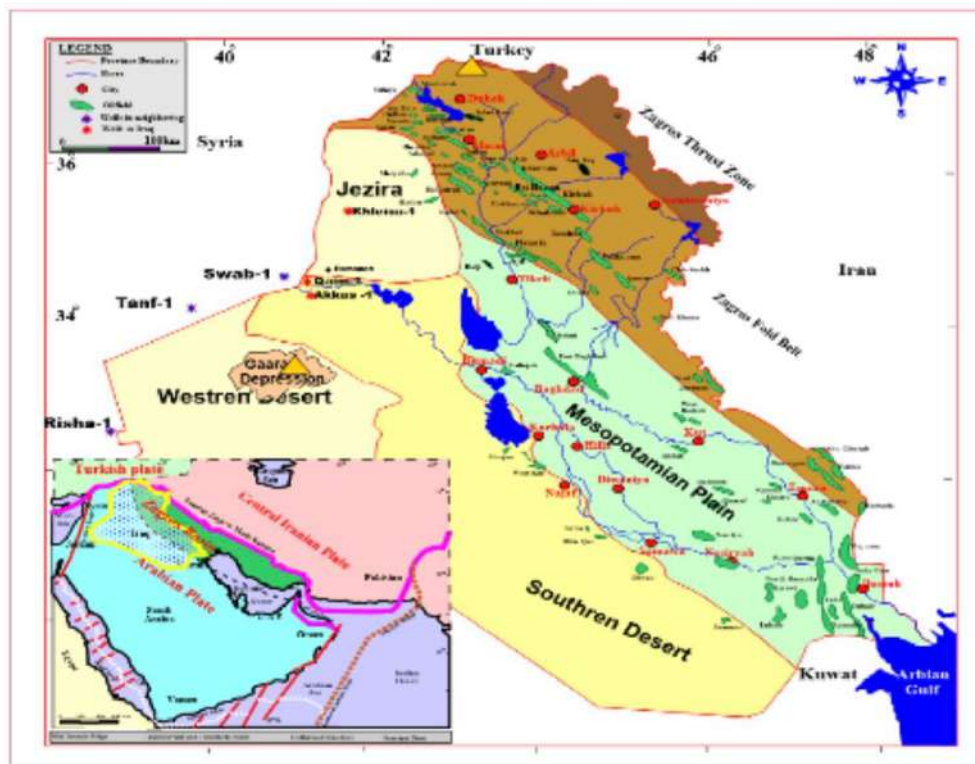
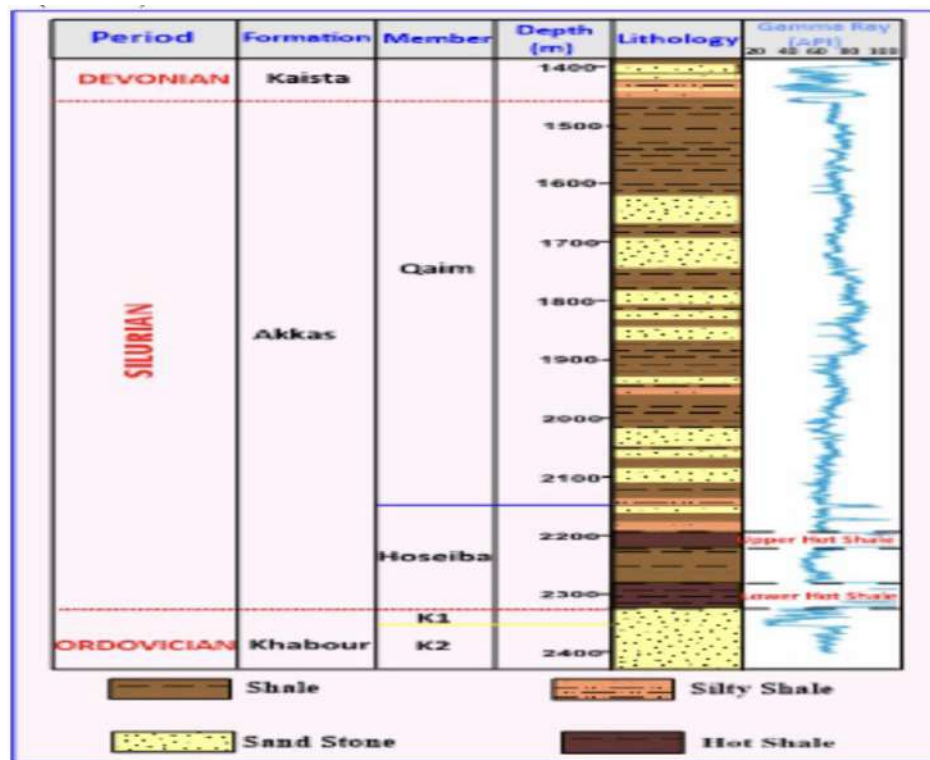


Fig 2.1.1: Location map of the lower Paleozoic three wells (Akkas-1, Qaim -1 and Khleisia-1) and Paleozoic outcrops of north Iraq. Iraq is located North East of the Arabian Plate. The structural provinces

.Fig 2.1.2: Hot shale, Hosiba Member, Upper Thinner and lower Thicker layer with high GR., Akkas Formation, Akkas-1 well, western Iraq are after Buday and Jassim (1987)



2.2 Source Rock Parameter

Important parameters include:

1. TOC (%): organic richness.
2. S1, S2, S3 from Rock-Eval pyrolysis.
3. HI = Hydrogen Index.
4. OI = Oxygen Index.
5. Tmax = maturity indicator.
6. Ro% = vitrinite reflectance equivalent.

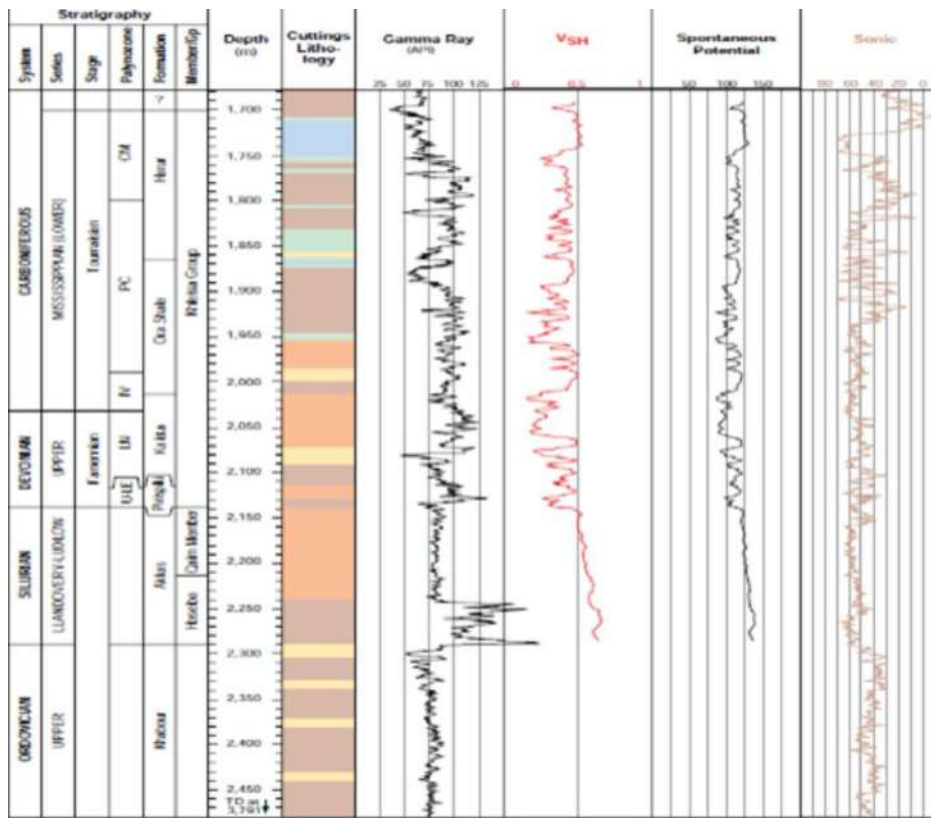


Fig 2.2.3: Khleisia well, Akkas Formation, Hosiba Member with hot shale, (40) m., Kh-1 well. (Al -Hadidy, 2007).

2.3 Reservoir Units

The main reservoir units in the Akkas Field include:

- Ordovician Khabour Formation (sandstones)
- Lower Silurian Akkas

“Hot Shale” Formation (source and seal rock)

- The Khabour Formation consists of tight sandstone reservoirs with heterogeneous porosity and permeability, making reservoir characterization challenging.
- The Silurian “hot shales” are highly organic-rich and act as both source rocks and regional seals, with Total Organic Carbon (TOC) values reaching up to 16%.

Microfractures significantly enhance secondary porosity and improve gas storage and flow capacity.

2.6 Previous Studies and Knowledge Gaps

Previous research has focused on:

- Structural characterization of the anticline system
- Petrophysical modeling of sandstone units
- Source rock geochemistry and maturation history
- Field development optimization and production forecasting

However, major gaps remain in:

- Integrated reservoir simulation under condensate blockage conditions
- Full 3D geological modeling of heterogeneity
- Optimization of production strategies in tight sandstone systems

2.7 Methodology

A standard methodological framework used in Akkas Field studies typically includes geological, geophysical, and reservoir engineering approaches.

2.7.1 Data Collection

Data sources include:

- Well logs (gamma ray, resistivity, density, neutron logs)
- Core samples and thin section petrography
- Seismic reflection data for structural interpretation
- Production and pressure test data
- Geochemical analysis of source rocks

2.7.2 Structural Interpretation

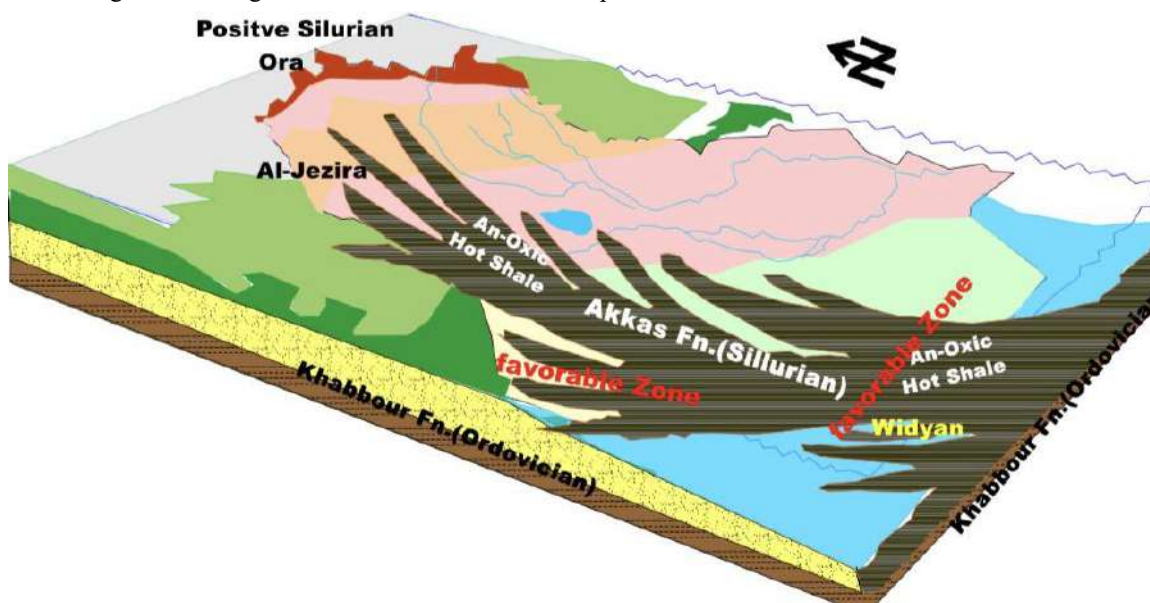
Seismic data is used to map the anticline structure and fault systems

Identification of fracture networks and tectonic trends (NW–SE orientation)

Structural depth conversion and horizon mapping

This step defines the trap geometry and migration pathways.

Fig 2.7.2.5: Fig.10. Schematic Silurian basin profile from west Akkas subbasin, Akkas-1 to NW Khlesia-1



showing on lap of lower Llandovery Hot Shale 1 into early Silurian paleo high in Khlesia-1

2.7.3 Stratigraphic and Facies Analysis

- Lithofacies classification of sandstone and shale intervals
- Correlation between wells to define reservoir continuity
- Identification of depositional environments (fluvial–marine transitional systems in Paleozoic succession)

2.7.4 Petrophysical Evaluation

Petrophysical parameters are derived from well logs:

- Porosity estimation (density/neutron logs)
- Permeability interpretation (core calibration)
- Water saturation using resistivity models
- Net-to-gross reservoir thickness estimation

2.7.5 Geological Modeling

A static geological model is constructed using software such as CMG Builder or Petrel:

Steps include:

1. Structural framework modeling
2. Facies modeling
3. Petrophysical property distribution
4. Zonation into reservoir flow units
5. Grid building for simulation

2.7.6 Reservoir Simulation

Dynamic modeling is performed to:

- Simulate gas and condensate flow behavior
- Analyze pressure depletion effects
- Evaluate condensate banking near the wellbore
- Forecast production performance

2.7.7 Production Optimization Analysis

Comparison of vertical vs. horizontal/directional drilling

Evaluation of fracture-enhanced productivity

Sensitivity analysis for well spacing and pressure drop

Economic assessment of development scenarios

Chapter Three: Results:

3.1 Kerogen type, Thermal maturity, Hydrocarbon Type

Published data indicate TOC values commonly range from 1% to 8% within Silurian shale intervals, representing fair to excellent source rock quality

Hydrogen Index values generally indicate mixed Type II/III kerogen, capable of generating oil at moderate maturity and gas at higher maturity.

Tmax and equivalent reflectance values suggest maturity levels from late oil window to dry gas window in deeper parts of Akkas.

Because of deep burial and advanced maturity, generated hydrocarbons are dominantly thermogenic gas.

So the Akkas Gas Field in western Iraq (Al-Anbar Province) is a large but technically complex natural gas accumulation located within a faulted anticline structure of the Interior Platform/Widyan Basin. Research shows that its main reservoirs are Ordovician–Silurian tight sandstones with very low permeability, where gas is mainly stored in fractures and microfractures rather than conventional pore spaces. The field contains predominantly methane-rich natural gas with condensate, with estimated gas in place of about 5.6 trillion cubic feet, making it one of Iraq’s largest gas resources. However, production is challenging due to reservoir tightness, high pressure, and issues such as gas condensate banking, which reduces flow efficiency. Studies indicate that successful development depends on advanced techniques like hydraulic fracturing, horizontal drilling, and reservoir stimulation, highlighting that while Akkas has high strategic value for Iraq’s energy sector, its recoverability is limited by difficult reservoir characteristics rather than resource size.

Table 3.1.1: Kerogen Classification and Hydrocarbon Potential

Kerogen Type	Source Material	Depositional Environment	Hydrocarbon Potential
Type I	Algae	Lacustrine (lake)	Oil-prone (Excellent)
Type II	Plankton + Algae	Marine environment	Oil & Gas (Very good)
Type III	Higher plants	Terrestrial (delta/coal)	Gas-prone (Moderate)
Type IV	Reworked/oxidized material	Various	Non-generative

Table 3.1.2: Source Rock Quality Based on TOC and S2 Values

Quality Level	TOC (%)	S2 (mg HC/g rock)	Interpretation
Poor	< 0.5	< 2	Insufficient organic matter
Fair	0.5 – 1	2 – 5	Limited potential
Good	1 – 2	5 – 10	Moderate hydrocarbon generation
Very Good	2 – 4	10 – 20	High potential
Excellent	> 4	> 20	Excellent source rock

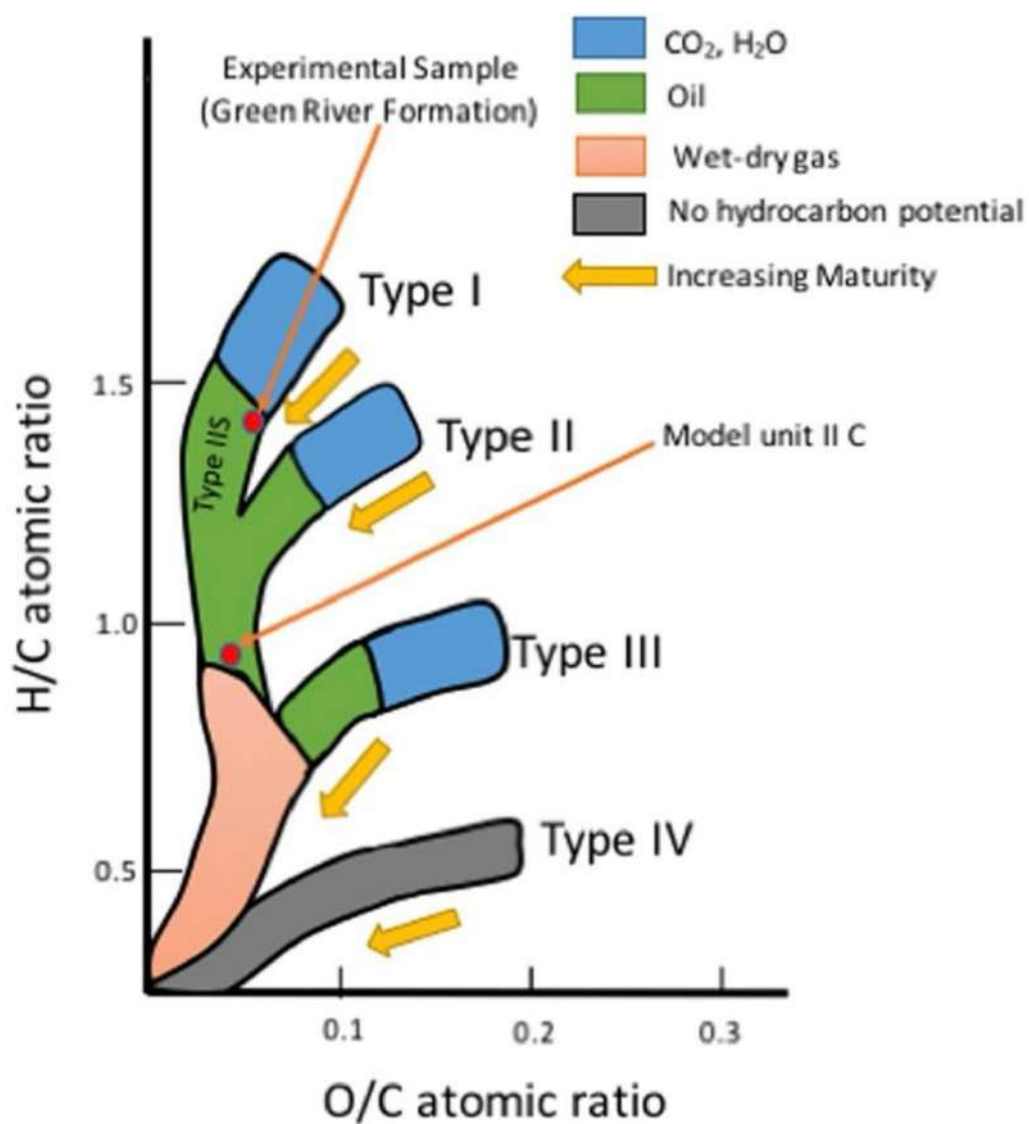


Table 3.1.3: Hydrogen Index (HI) and Hydrocarbon Type

Hydrogen Index (mg HC/g TOC)	Kerogen Type	Hydrocarbon Type
< 150	Type III/IV	Gas
150 – 300	Type II/III	Mixed (Oil + Gas)
> 300	Type I/II	Oil-prone

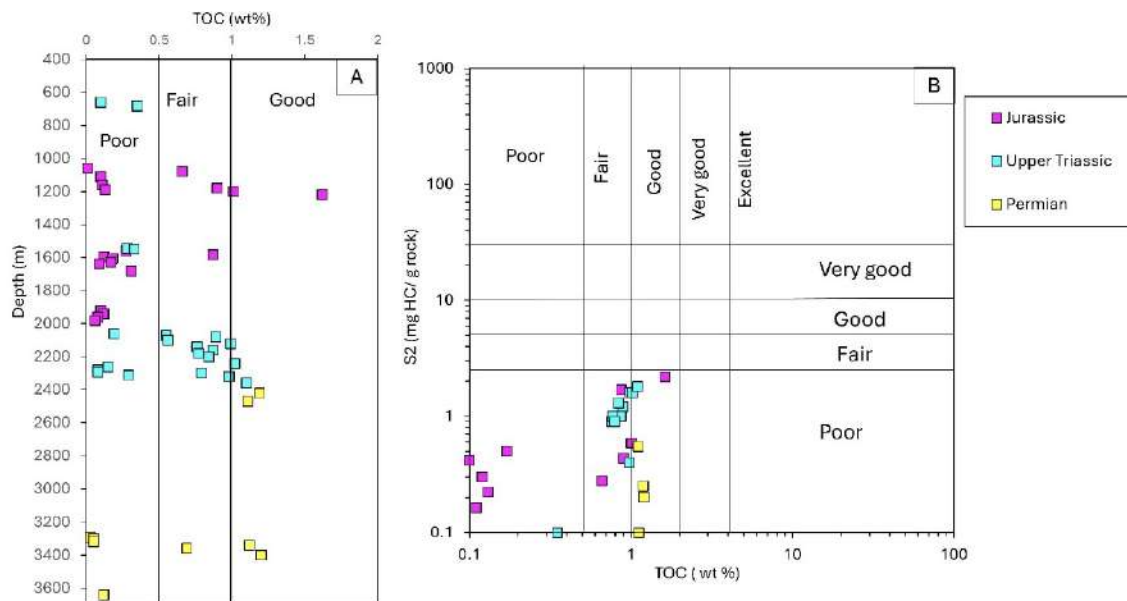


Table 3.1.4: Thermal Maturity Classification Based on Tmax

Tmax (°C)	Maturity Stage	Hydrocarbon Generation
< 435	Immature	No generation
435 – 455	Oil Window	Oil generation
455 – 470	Late Oil / Wet Gas	Oil + Gas
> 470	Dry Gas Window	Gas generation

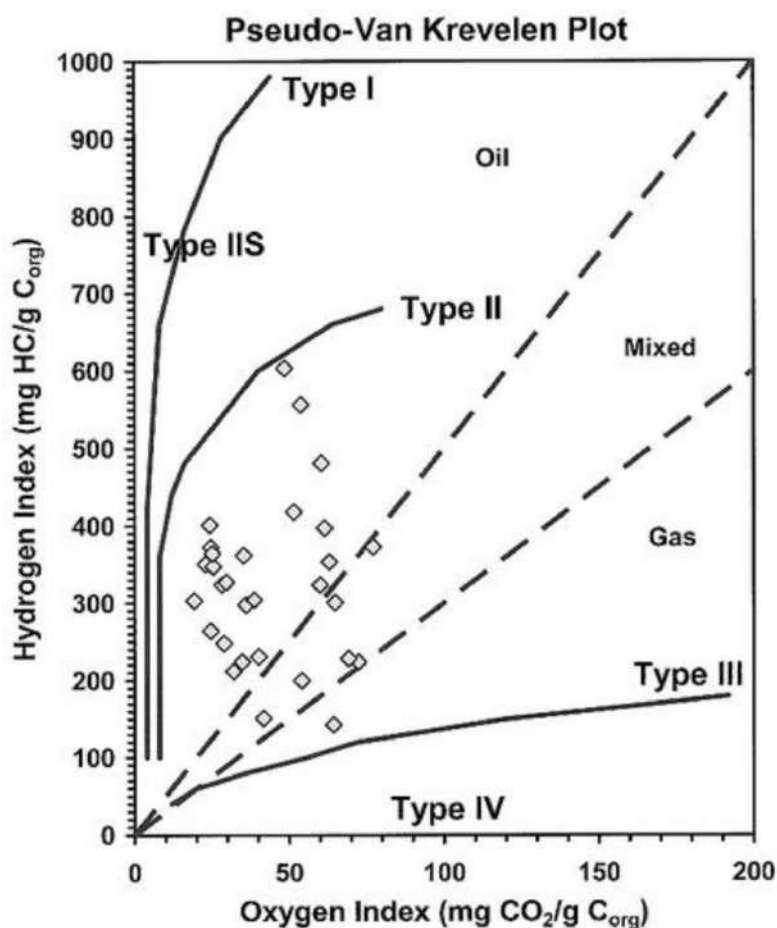


Table 3.1.5: Geochemical Parameters of Akkas Formation

Sample / Well	TOC (%)	S1	S2	HI	Tmax (°C)	Interpretation
Akkas-1	2.5	...	...	220	460	Gas-prone
Qaim-1	3.1	...	...	250	455	Mixed
Khleisia-1	1.8	...	...	180	470	Dry gas

Table 3.1.6: Summary of Thermal Maturity Indicators

Parameter	Range	Interpretation
Tmax	450–470 °C	Mature to overmature
Ro%	1.0–1.5	Gas window
PI	0.2–0.4	Active generation

Table 3.1.7: Reservoir Properties of Akkas Field

Property	Value	Interpretation
Porosity	Low	Tight reservoir
Permeability	Very low	Requires stimulation
Fractures	Present	Enhance flow
Fluid type	Gas + condensate	Gas system

3.2 Location & Geological Setting

- Located in the western desert of Iraq (Al-Anbar Province) near the Syrian border.
- Part of the Widyan Basin / Interior Platform petroleum system.
- The field is a faulted anticline structural trap formed by uplift and folding.
- Main reservoir formations:
- Ordovician Khabour Formation
- Lower Silurian shales and sandstones

3.3 Reservoir Characteristics

- Reservoir is mainly tight sandstone with shale interbeds, making it heterogeneous and low-permeability.
- Contains gas condensate and dry/wet gas (mainly methane and ethane).
- Natural fractures and microfractures significantly improve storage and flow capacity

3.3. Reserves & Capacity

- One of Iraq's largest natural gas fields.
- Estimated original gas in place:
- ~5.6 trillion cubic feet (Tcf) total gas (older studies)
- Other development studies estimate recoverable volumes around 4.5 Tcf
- Some development papers also reference ~9 BSCF (study-specific reserve classification differences) depending on modeling assumptions.

3.4 Production & Development Challenges

- Reservoir is deep, high-pressure, and low permeability, making production difficult.
- A key problem is gas condensate banking, which reduces flow when pressure drops below dew point.
- Engineering solutions studied include:
- Hydraulic fracturing
- Directional and horizontal drilling
- Well stimulation techniques

3.5 Key Geological Findings

- Gas is stored mainly in fractures and microfractures rather than only rock pores.
- The field was affected by tectonic uplift and folding, creating NW–SE anticline structures.
- Source rocks are mainly Ordovician–Silurian black shales (marine organic origin).

3.6 Importance for Iraq

- Considered Iraq's largest onshore gas field in the western region.
- Strategically important for:
- Domestic electricity supply
- Reducing gas imports
- Expanding western Iraq energy infrastructure

Chapter Four: Dissections:

4.1 Source Rock Effectiveness

The Silurian hot shale is considered the main effective source rock across western Iraq and neighboring Arabian basins.

4.2 Why Akkas is Gas-Prone

Deep burial increased temperature over geological time, cracking previously generated oil into gas and condensate.

4.3 Exploration Significance

Additional undiscovered gas accumulations may exist in undrilled Paleozoic structures across the Western Desert.

4.4 Total Organic Carbon (TOC) and Organic Richness

The analyzed shale samples from the Akkas Formation show a wide variation in TOC values between the two main members:

Hoseiba Member (hot shale):

- TOC ranges from ~1.3 to 9.6 wt% (Table 1 data)
- Average values commonly exceed 4–6 wt%
- Indicates good to excellent source rock quality

Qaim Member:

- TOC values generally < 3 wt%
- Represents poor to fair source rock potential

These results are consistent with regional studies showing that the Hoseiba “hot shale” interval is the principal hydrocarbon source rock, with average TOC around ~5.5 wt%

Sam ple num ber	num ber	Analysi s by	DP H	S1	S2	S3	Tm ax	G PI	T PI	RO C	TO C	MGS2/G TOC	O I
AK3	Qaim	Ocean grove	21 22	0. 59	1.6 3		431	0. 00	0. 27	0.9 8		166	
AK3	Qaim	Ocean grove	21 23	0. 14	0.8 7		434	0. 00	0. 14	0.5 2		1672	
AK3	Qaim	Ocean grove	21 24	3. 84	8.1 2		431	0. 00	0. 32	3.1 1		261	
AK3	Qaim	Ocean grove	21 26	0. 43	4.8 0		441	0. 00	0. 08	4.5 7		105	
AK3	Hosi ba	Ocean grove	21 96	0. 58	4.4 0		427	0. 00	0. 12	6.1 3		72	
AK3	Hosi ba	Oceang rove	22 00	0. 71	5.0 0		430	0. 00	0. 12	4.7 6		105	
AK3	Hosi ba	Ocean grove	22 10	1. 06	17. 27		436	0. 00	0. 06	6.2 6		276	
AK3	Hosi ba	Ocean grove	22 56	0. 64	2.4 3		434	0. 00	0. 21	1.3 6		179	
AK3	Hosi ba	Ocean grove	22 66	0. 63	1.5 7		434	0. 00	0. 29	0.9 9		159	
AK3	Hosi ba	Ocean grove	22 78	1. 25	5.9 3		439	0. 00	0. 17	2.0 1		295	
AK3	Hosi ba	Ocean grove	23 05	0. 67	3.6 6		439	0. 00	0. 15	1.8 6		197	
AK3	Hosi ba	Ocean grove	22 96	0 6	1.1 6		428	0. 00	0. 00	1.2 3		94	
AK3	Hosi ba	Ocean grove	23 04	0. 94	8.6 8		432	0. 00	0. 10	5.2 8		164	
AK3	Hosi ba	Ocean grove	23 08	1. 05	4.6 8		385	0. 00	0. 18	2.0 3		36	4 3
AK3	Hosi ba	Ocean grove	23 14	0. 23	4.1 5		431	0. 00	0. 51	1.5 7		155	7 3
AK1	Qaim	Ocean grove	23 24	2. 02	0.2 1	0. 25	401	0. 00	0. 23	0.5 8		49	4 4
AK1	Qaim	Ocean grove	17 50	6. 27	0.5 1	0. 24	433	0. 00	0. 43	0.3 3		216	
AK1	Qaim	Ocean grove	18 95	0. 98	0.3 1	0. 28	438	0. 00	0. 22	0.6 3		260	5
AK1	Hosi ba	Ocean grove	20 30	1. 29	7.1 2		436	0. 00	0. 43	5.5 6		135	
AK1	Hosi ba	Ocean grove	22 10	0. 34	24. 91	0. 48	438	0. 00	0. 20	9.5 8		296	
AK1	Hosi ba	Ocean grove	22 22	0. 15	2.6 1		436	0. 00	0. 27	1.9 4		211	
AK1	Hosi ba	Ocean grove	23 03	0. 22	4.5 3		438	0. 00	0. 22	1.5 3		231	

AK1	Hosi ba	Ocean grove	23 21	2. 02	1.1 4		432	0. 00	0. 27	0.5 4		135	

Table4.4.8: XRD data for shale samples of the Akkas Formation from the Akkas-I and Akkas-3 wells.

Sample number	S0	S1	S2	S3	Tmax	GPI	OPI	TPI	ROC
AK1	0.00	0.32	0.00		361	0.00	0.59	0.59	28
AK1	0.00	0.22	0.22		438	0.00	0.44	0.44	147
AK1	0.00	0.08	0.28		399	0.00	0.40	0.40	46
AK1	0.00	0.16	0.12		432	0.00	0.43	0,43	81
AK1	0.00	0.05	0.21		361	0.00	0.50	0.50	125
AK1	0.00	0.15	0.05		427	0.00	0.48	0.48	30
AK1	0.00	0.60	0.16		365	0.00	0.53	0.53	64
AK1	0.00	0.34	0.54		330	0.00	0.68	0.68	21
AK1	0.00	0.36	0.16			0.00	0.71	0.71	20
AK1	0.00	0.29	0.54		430	0.00	0.51	0.51	156
AK1	0.00	0.12	0.16		454	0.00	0.32	0.32	42
AK1	0.00	0.11	0.15		408	0.00	0.32	0.32	27
AK1	0.00	0.05	0.28			0.00	0.45	0.45	55
AK1	0.00	0.31	0.25	0.22	362	0.00	0.54	0.54	37
AK1	0.00	0.17	0.23	0.15	379	0.00	0.50	0.50	53
AK1	0.00	0.31	0.06	0.32	367	0.00	0.36	0.36	53
AK1	0,00	0.23	0.26	0.13	401	0.00	0.43	0.43	49
AK1	0.00	0.07	0.17	0.23		0.00	0.35	0.35	32
AK1	0.00	0.16	0.54	0.14	439	0.00	0.37	0.37	87
AK1	0.00	0,12	0.31	0.20	438	0.00	0.46	0.46	64
AK1	0.00	0.08	0.16	0.16	432	0.00	0.33	0.33	26

Table4.4.9: C/Pyrolysis data for the Khabour Formation in the Akkas-1 well and Chia Zinnar section.

4.4 Total Organic Carbon (TOC) and Organic Richness

The analyzed shale samples from the Akkas Formation show a wide variation in TOC values between the two main members:

Hoseiba Member (hot shale):

- TOC ranges from ~1.3 to 9.6 wt% (Table 1 data)
- Average values commonly exceed 4–6 wt%
- Indicates good to excellent source rock quality

Qaim Member:

- TOC values generally < 3 wt%
- Represents poor to fair source rock potential

4.5 Rock-Eval Pyrolysis Parameters:

Rock-Eval data (S1, S2, S3) indicate:

S2 values (hydrocarbon generation potential):

- Hoseiba Member: up to ~25 kg HC/ton
- Qaim Member: generally < 5 kg HC/ton

Hydrogen Index (HI):

- Ranges from ~70 to 295 mg HC/g TOC
- Higher HI values (>200) in some Hoseiba samples suggest Type II kerogen
- Lower values indicate mixed Type II–III kerogen

Production Index (PI):

Mostly low (<0.3), indicating limited expulsion and early to peak generation stage

4.6 Kerogen Type and Hydrocarbon Potential:

Based on HI and S2:

- Dominant kerogen type: Type II (marine origin) with some Type III input
- Indicates potential for:
- Gas-prone systems
- Minor oil generation in richer intervals

This aligns with studies confirming marine-derived organic matter in Silurian shales of Akkas

4.7 Thermal Maturity (Tmax Data):

Tmax values range between ~427°C and 441°C

Interpretation:

- <430°C: immature to early mature
- 430–435°C: early oil window
- >435°C: peak oil to wet gas window

Most samples fall within:

- Early to peak maturity stage
- Suggesting active hydrocarbon generation

4.8 Source Rock Zonation

Two distinct source rock intervals are identified:

a. Lower Hoseiba Member (“Hot Shale”)

- High TOC and S2
- Thick (~20–60 m)
- Regionally extensive
- Excellent source rock

b. Upper Qaim Member

- Lower organic richness
- Limited hydrocarbon generation
- Secondary or poor source rock

4.9 Khabour Formation (Supporting Data from Table):

- TOC values: generally <1 wt%
- HI values: low to moderate
- Tmax: ~360–454°C

Geochemical indicators suggest:

Anoxic marine conditions for Hoseiba Member

More oxic conditions for Qaim Member

Chapter Five: Conclusion

5.1 Conclusions

1. Early Paleozoic rocks in Akkas contain regionally significant source intervals.
2. Silurian organic-rich shale is the principal source rock.
3. Kerogen is mainly Type II/III with good generative potential.
4. Thermal maturity is mature to overmature, favoring gas generation.
5. Akkas remains a high-priority exploration target in Iraq.

Chapter six: References

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**Ministry of Higher
Education
and Scientific Research**



**Alkitab University
College of Petroleum Engineering**

Title:

**Geochemical evaluation and reservoir continuity of Zubair and
Mishrif reservoirs in Zubair Super Giant oil field.**

Supervisor:

Mr. Abdulaziz Al-Hasani

By:

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Ali Nael Majeed**

2026



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Essa moayed younis
Younis Hassan Younis
Ali Nael Majeed

Abstract

This study was accomplished for geochemical evaluation and reservoir continuity for the Mishrif and Zubair Formations in the Zubair oilfield, southern Iraq.

The hydrocarbon generation ability of probable source rocks in the Zubair oil field has been studied using Rockeval (6). Therefore, the samples prepared from the possible source rocks of this field have been subjected to preliminary and supplementary geochemical analyses. SARA and GC tests and Rockwell 6 analyses were also used in this study.

The results obtained from the pyrolysis geochemical analysis of Rockwell from the Mishrif, Lower, and Upper Zubair Formations indicate type III and II kerogens and a small amount of type III and II/III respectively.

The Mishrif, Upper, and Lower Zubair Formations have poor, good to excellent, and fair to good hydrocarbon generation characteristics respectively.

The obtained Rockwell data indicate that the organic matter content of the Mishrif Formation is immature, while the upper and lower Zubair Formations are mature. The results obtained from the vitrinite reflectance values of the studied samples confirm the results obtained from Rockwell pyrolysis.

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Chapter One

Introduction

1-1- General

The correlation of crude oils with each other in the source rocks is a valuable tool for exploration, which can answer the essential questions of exploration and production and expand the current exploration trends [1]. When two or more reservoirs are discovered in a relatively unexplored area, many questions are raised regarding the lateral and vertical expansion of the production process. Are the oils from the same family or the sequence of certain rocks? Is each of these oils related to potential shallower or deeper accumulations? Can the known leaks in the tank be correlated to the underground tanks? [2].

The Biomarkers known as chemical fossils can be considered organic structures, which are very similar to their ancestral organisms in terms of chemical composition. The formation of these compounds in sediments occurs directly or because of catagenetic and diagenetic changes [3]. Two essential features should be considered to trace the effect of biomarkers in oil, firstly, they have their order in terms of structure, and then in terms of abundance, they should be in such a way that their effect can be studied in oil. Among petroleum systems' most essential and abundant biomarkers are normal paraffin, persistent, phytane, hopanes, and 4- and 5-ring esters [4].

Despite the fact that the Mesopotamia basin is classified as one of the largest hydrocarbon basins in the world, there has been a poor study of petroleum systems, especially in southern Iraq, and only very little research has been published. The Zubair subzone contains several known hydrocarbon fields. Upper Jurassic-Lower Cretaceous source rocks of this basin, which are rich in organic matter, have high hydrocarbon production potential, and produce liquid hydrocarbon phases. The most significant petroleum in the Mesopotamian basin is the (Jurassic-Cretaceous) petroleum system [5]. In the absence of information about the area, they are unknown. In the area of freezing accumulations, the geological history and evolution of the basin have been studied. Preliminary geochemical studies of the Upper Jurassic-Lower Cretaceous sequence of the Zubair basin subzone have been carried out. To reach the degree, maturity is classified [6].

Zubair oilfield is one of the most significant oilfields in south Iraq, which can produce oil from the reservoirs of Zubair and Mishrif. One of the crucial points for the oils located in an oilfield, which have the same geological history is their similarity in terms of physical characteristics,

origin, and maturity. These oils have many similarities in terms of physical properties such as; the biomarker and physical properties such as; specific gravity, density, and sulfur content. One of the best ways to identify these petroleum compounds is to use tools such as gas chromatography (GC) [7]. The chemical compounds calculated by gas chromatography can be considered an index of reservoir properties and a fingerprint of reservoir oil. By the fingerprint method, reservoir horizons in different connected wells can be determined, and used to solve problems of reservoir management, production, and development engineering. It is possible to specify the continuity of the reservoir in terms of size and extent of expansion by this method. Finally, it is possible to determine the field development maps and the number and location of the wells necessary for drilling [8]. Reservoir geochemistry is a suitable method and tool to identify fluid flow passages and obstacles in hydrocarbon reservoirs.

1-2- Methodology

The essential part associated with massive costs in oil companies is exploration and development programs and production management from hydrocarbon reservoirs [9]. The reservoir data integration and geological information are crucial in reducing the costs and risks of related activities. In this regard, investigating the physical and chemical interactions governing the components of the petroleum system, such as source rock, reservoir, and cover rock, is very important. [10]. Among the other essential things in an oil system that play a vital role in the development and management of production is to achieve a precise understanding of the relationship between hydrocarbon reservoirs in terms of their separation or continuity and the history of their filling [11]. The horizontal and general relationship for hydrocarbon reservoirs is the key to identifying reservoir models and new exploration horizons in oil fields. During the last few decades, geological data, petrophysical logs, seismography, and pressure have been used to model the continuity of hydrocarbon reservoirs [12]. Each available data provides information about a specific part of the tank, and the efficiency will be related to the time when these data are combined and used. Nowadays, reservoir geochemical data is widely used as a complement to other existing methods [13]. When the geological and seismic data of good quality are unavailable or similar reservoirs, this method can determine the continuity or discontinuity of hydrocarbon reservoirs. In this method, by using the characteristics of reservoir fluids, it is

possible to specify the history of reservoir filling, and compared to other methods, the cost is relatively lower.

1-3- Area of study

1-3-1- Zubair oilfield

Zubair Field lies back in the Mesopotamian zone within an unstable sill of the Arabian Platform [14]. Zubair is one of the mature oilfields in the southern part of Iraq; it is located 20 km southwest of Basra city [15]. (Figure 1-1)

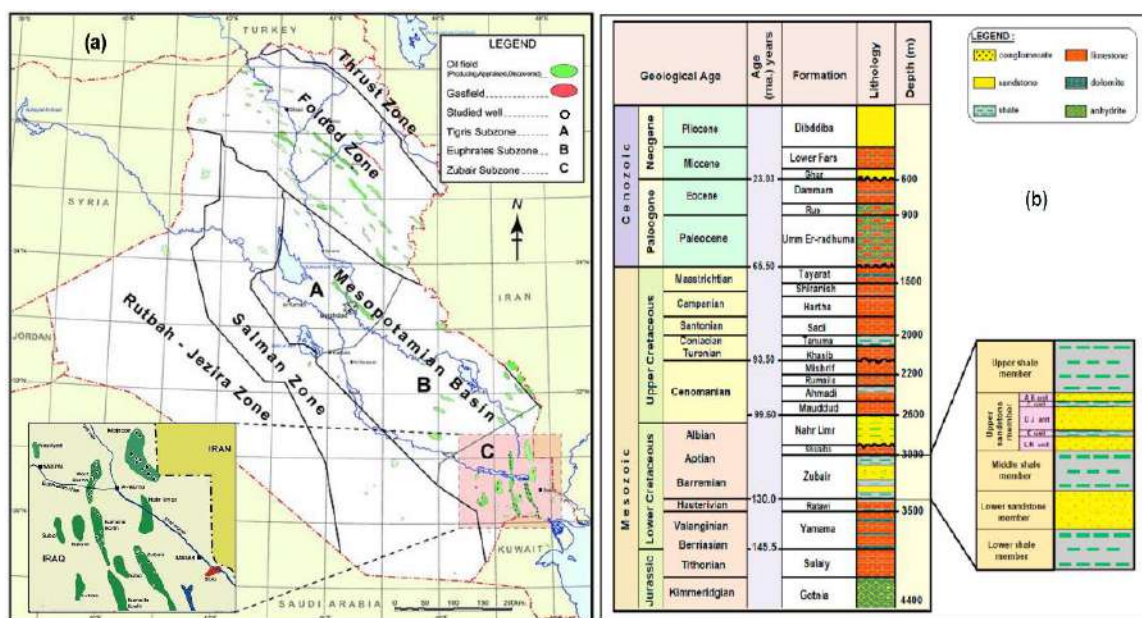


Figure 1-1: (a) locations of the wells under study, (b) Stratigraphic column in southern Iraq [16, 17]

This field was discovered in 1949 consisting of four domes (Al-Hamar, Shuaiba, Rafidyah) in the NW and (Safwan) to the SE communicated with each other through an aquifer extending beyond the Iraqi and Kuwaiti border [18]. The field structure includes four reservoirs, Mishrif, Upper Shale Membrane, Third and Fourth Pay zone [19].

1-3-2- Mishrif formation

Mishrif Formation is divisible by a prominent unconformity into two large-scale regressive sequences, which are particularly distinguishable in the east of the Mesopotamian Basin. Multiple reservoir units are present in both sequences. The west of the basin is dominated by the lower sequence, which has relatively few reservoir intervals. The shallow-water reservoir units in the east of the basin are thick, reflecting relatively high subsidence rates throughout the Cenomanian [20]. Subsidence rates in the western side of the basin were lower, and reservoir units are thinner and more limited.

The best reservoir conditions in the Mishrif Formation occur in rudist-bearing facies, such as rudstones and rudistid packstone/grainstones [21]. (Figure 1-2)

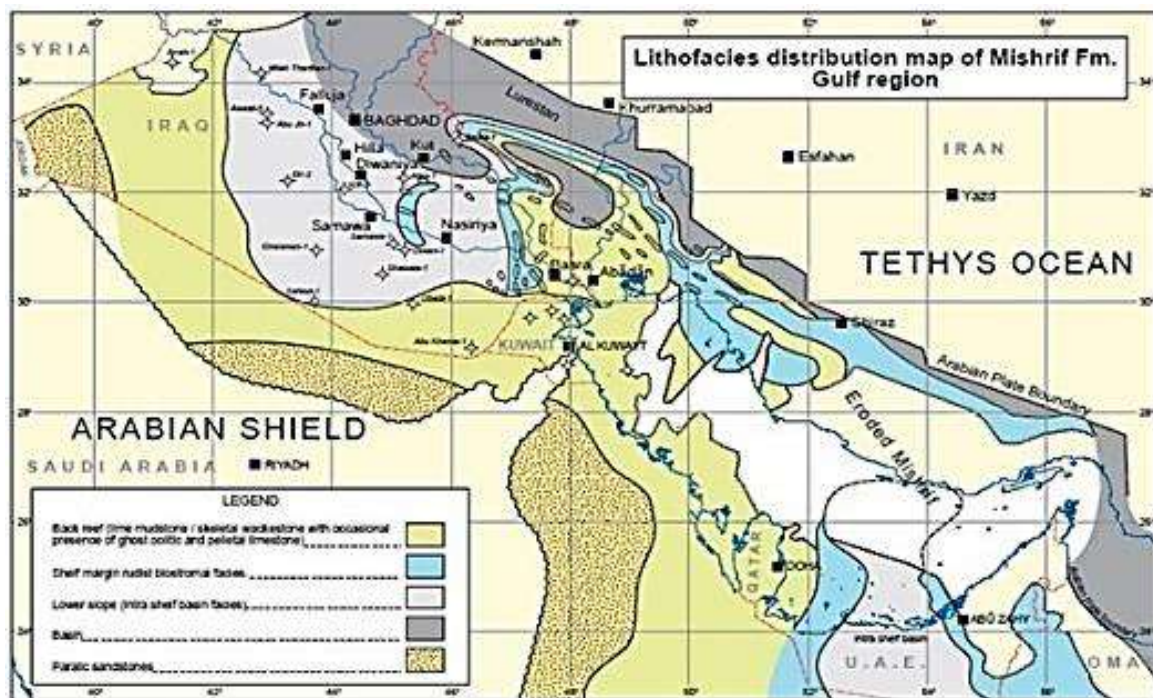


Figure 1-2: Lithofacies Distribution for Mishrif Formation in Persian Gulf Region [22]

The depth of the Mishrif Formation in the Zubair and Rumaila oilfields is 270 meters. The Nahr Omar and Majnoon oilfields along the border of Iraq and Iran of 435 meters, and the Abu Amoud field is 380 meters, the bottom boundary of the formation is the slope usually, and the underlying unit in southern Iraq is generally the Rumaila Formation, in the west Msad Formation. The Mishrif Formation of Iraq is comparable to the Mishrif Formation and the upper part of the Maqwa Formation in Kuwait, the Sarvak Formation in Zagros, the upper part of the Judea

Formation in central and NE Syria, and the Mardin Formation in SE Turkey. Mishrif Formation is an essential middle Cretaceous carbonate reservoir precipitation during the Cenomanian-Early Turonian. Mishrif Formation lies over Rumaila Formations in gradational contact between the two and is uncomfortably overlain by the Khasib Formation (Figure 1-3) [23].

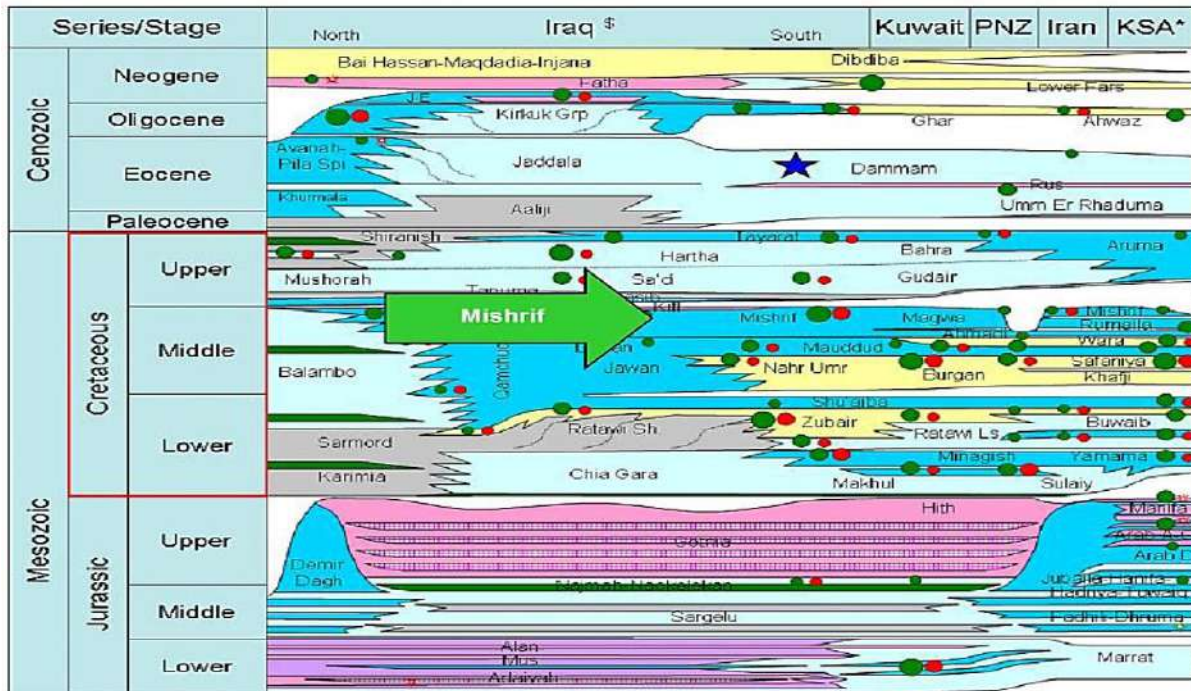


Figure 1-3: Geologic age Column of Mishrif Formation

The deposition of formation represents rudist shoals and patch reefs over rising subtle structural highs materializing in an otherwise moderately deeper rack on which maritime residues of the Rumaila Formation were deposited [24].

1.3.3 Zubair Formation

Zubair Formation is an early Cretaceous (Hauterivian to Early Aptian) age, regionally extensive oil producing sandstone sequence in Syria, Iraq, and Iran [25]. The Zubair sandstones are environmentally and genetically similar to the Nahr Umr sandstones of the Kuwaiti fields consisting of clean, well-sorted quartz arenites, sourced from the Arabian shield and deposited from west to east into the Mesopotamian basin in early Cretaceous time. Zubair sandy deposits consist of numerous depositional cycles composed of shallowing-upward successions of dark

grey shale, siltstone, and fine to medium-grained sandstone [26] (Figure 1-4). The cycles are interpreted to reflect a series of transgressions and regressions of sea level that developed during a longer-term transgression. Typical lithofacies associations within these cycles include marine shelf, prodelta, delta front, and delta plain [27]. From the litho-stratigraphic point of view, the formation is subdivided into five sub-units:

- Upper Shale Member, contains isolated, massive (10-15 m-thick) oil-bearing sandstones. This unit has been producible from few wells (e.g. Zb-X7).
- Upper Sandstone Member (Third Pay), has stacked pay sands and contains a 32° API gravity oil. This reservoir unit has been producible from a total about 80 wells.
- Middle Shale Member.
- Lower Sandstone Member (also known as Fourth Pay) is composed of stacked pay sands containing 38° API gravity oil. This unit has been producible from eight wells.
- Lower Shale Member.

Each of the reservoir units is to be isolatable by intervening shaly zones. The reservoir drive mechanism is mainly gas expansion with a weak to moderate water drive [28].

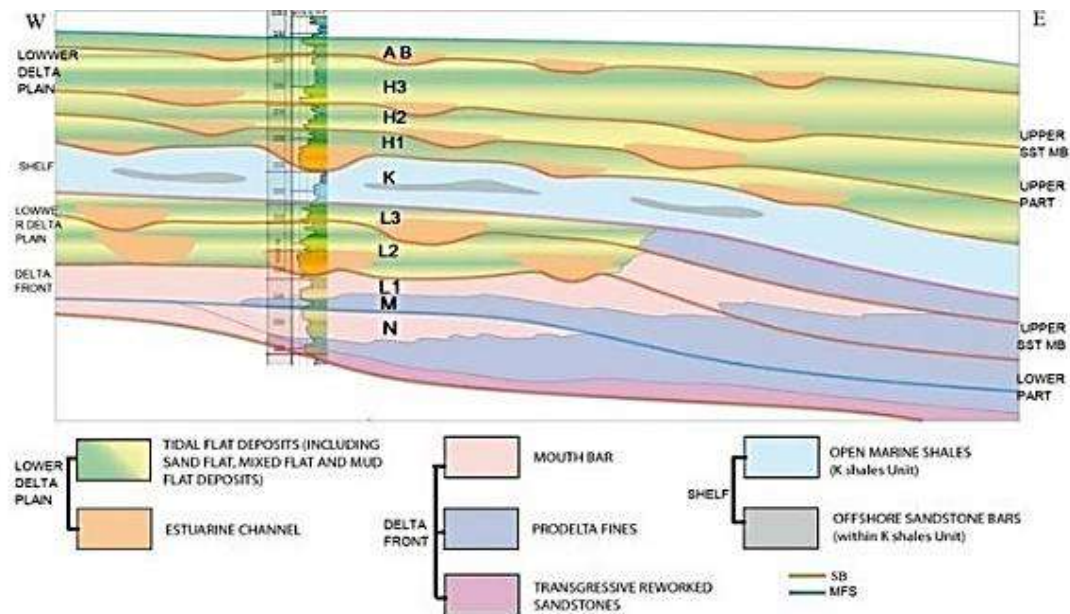


Figure 1-4: Lithofacies Distribution for Zubair Formation [29]

1-4- Research objectives

The objectives of this study can be stated as follows:

1. Description of the composition of Cretaceous oil biomarkers in the southeast (Zubair subzone) and determining their maturity in the Zubair oilfield.
2. Determining the geochemical and oil generation characteristics of Mishrif and Zubair reservoirs using oil-oil matching methods
3. Classification of oils in Zubair and Mishrif reservoirs based on oil-oil correlation.
4. Determination of possible source rocks and identification of their paleo-sedimentary environment.
5. Combining geochemical information with lithology data and reservoir pressure of hydrocarbon fluids

1-5-Research hypotheses

1. It seems that it is possible to determine the maturity level of crude oil in the Mishrif and Zubair reservoirs using of biomarkers.
2. It is possible to determine the oil geochemical and reproductive characteristics in Mishrif and Zubair reservoirs using the oil-oil matching method.
3. When using oil-oil correlation, it is possible to classify the oil in the studied reservoirs and to determine its possible source rock and paleo-sedimentary environment.
4. By integrating geochemical data and reservoir engineering data, an accurate assessment of the continuity or lack of continuity of Mishrif and Zubair hydrocarbon reservoirs can be determinable.

Chapter TWO

Research Methodology

2-1-Introduction

Geochemical research requires a series of experiments. The present research is not an exception to this rule, and it is necessary to carry out various experiments in the field of geochemistry. As stated in the objectives of the study, in this geochemical research, the hydrocarbon generation ability of probable source rocks in the Zubair oil field has been studied using Rockwell (6) and gas chromatography. Therefore, the samples prepared from the possible source rocks of this field have been subjected to preliminary[30] and supplementary geochemical analyses. In this study, SARA and GC tests and Rockwell 6 analyzes were also used.

2-2- Work steps and methods used in this study

The first step in the study of source rock samples is a petroleum sampling system and their preparation for organic geochemical analysis, pyrolysis, TOC measurement, extraction of bitumen present in source rock samples, and separation of oil fractions. Bitumen is taken into consideration in another part of this study. For the saturated slices, a complementary gas chromatography analysis is also performed

2-2-1- Selection of rock samples of possible origin

The purpose of this study is to evaluate the geochemical source rocks in the southern oil field on the common border of Iraq and Iran. One of the most accurate tools for evaluating hydrocarbon generation and geochemistry of source rocks of hydrocarbon reservoirs is the use of Rockwell pyrolysis analysis and gas chromatography. In order to evaluate the probable source rocks of the Majnoon oil field, 75 samples of drilling fragments belonging to the Zubair, Mishrif, and Najmeh formations were selected. The geographical location of the studied well is confidential due to its location on the common border between Iraq and Iran, and it is not possible to publish its location on behalf of the Iraqi National Oil Company.

About 50 grams of mother rock is required for geochemical analysis. In the first step, it is better to wash the drill bits using fresh water and salt water. Because with the passage of time, it is difficult to separate mud from samples[31]. In other methods, the mud stuck to the surface of the

harvested samples is washed with salt water or fresh water. After separating mud particles from the surface of the sample, using the dry air method, at a temperature of 40 degrees, before entering the laboratory and washing again, the deposited materials are separated from them (Figure 2-1).

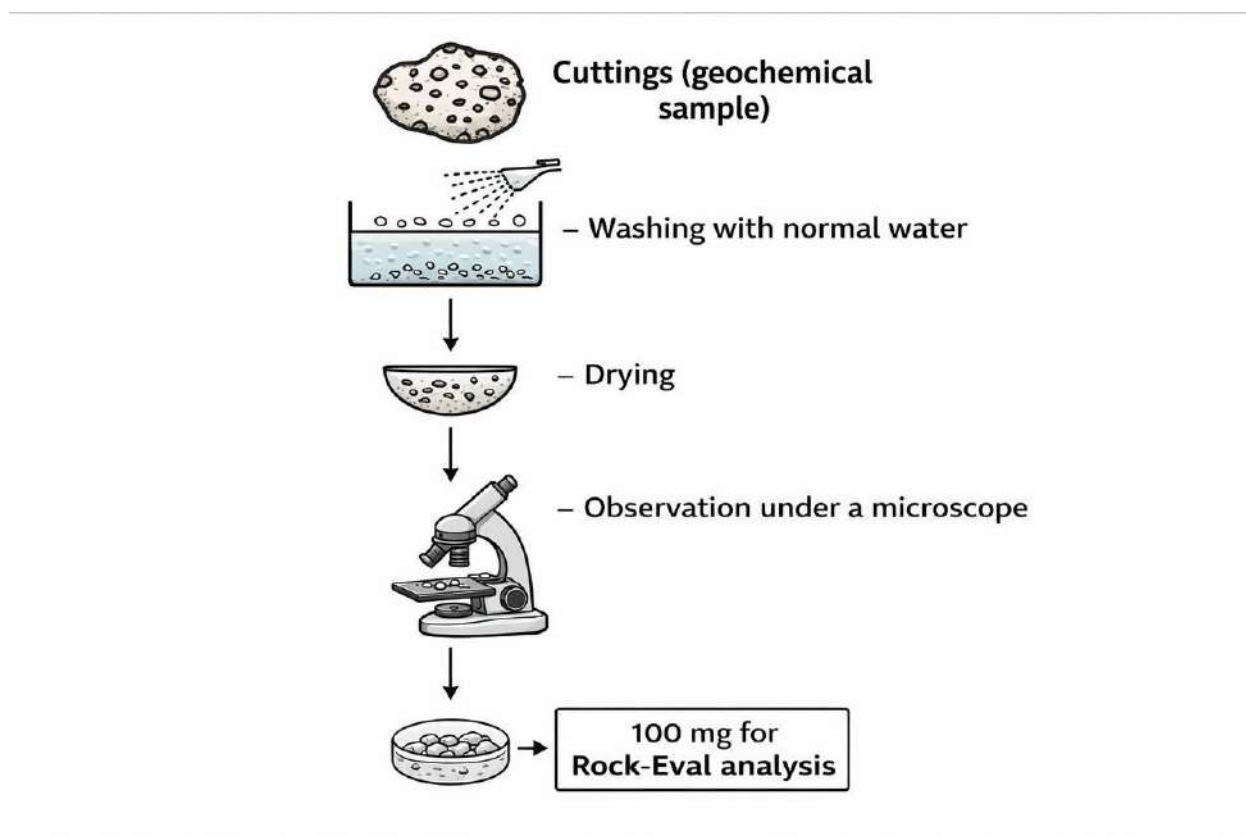


Figure 2-1: Schematic of sample preparation method for geochemical analysis of drilling cuttings

The steps of washing and preparing the samples are respectively: drying the wet samples using an oven, [32]pulverizing the samples using a mortar, sieving until reaching a certain sieve size, and washing the sample and solvent are used (Figure 2-2).



Figure 2-2: Tools used in the sample preparation section for geochemical analysis

2-2-2- General stages of geochemical analysis

At first, core samples and drilling chips are made into powder in the preparation section. About 100 mg of the powdered sample is transferred to the pyrolysis section. Another part of the sample is transferred to the bitumen extraction section, and it is removed using a Soxhlet device[33]. The

asphaltene extracted from bitumen enters the column chromatography section to separate other components such as resin compounds, aromatics and saturated hydrocarbons from it, and finally enter the gas chromatography machine[34] (Figure 2-3).

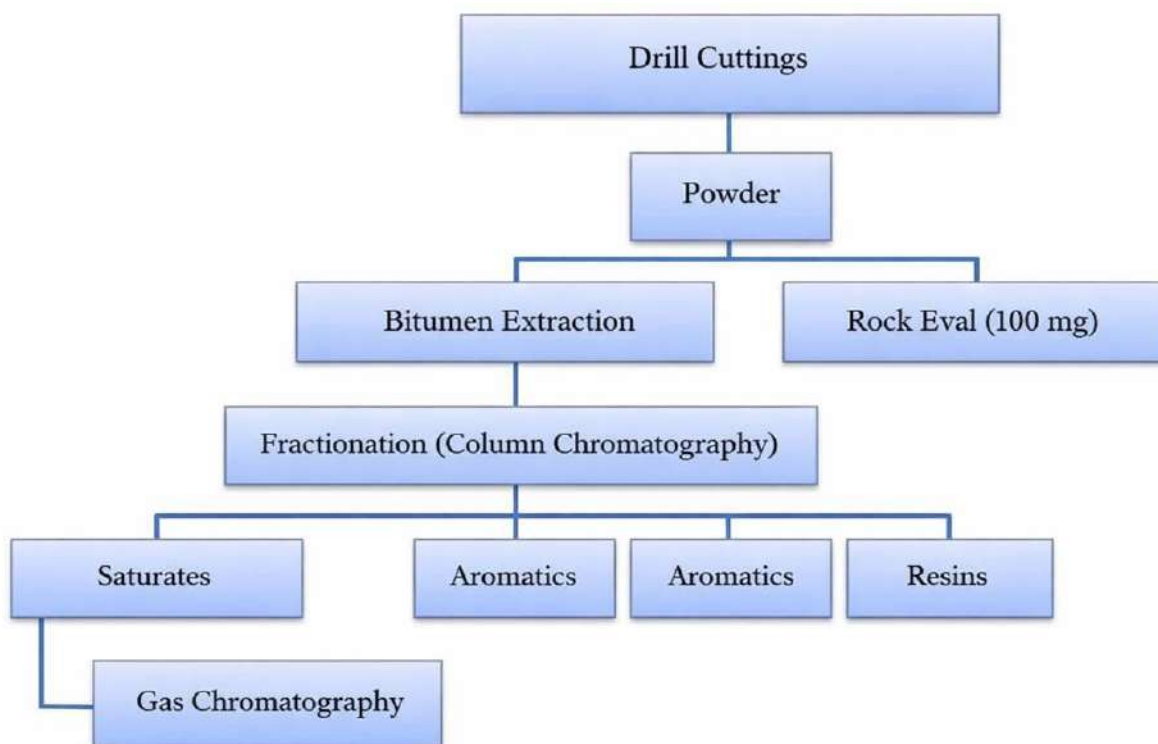


Figure 2-3: The sequence of the analysis of geochemical samples

2-3- Tests performed on samples

The geochemical analysis of source rock generally takes place in two general stages:

- 1- Preliminary tests
- 2- Additional geochemical tests

2-3-1- preliminary tests

Preliminary investigations are carried out on the pulverized samples of the source rock using the Rockwell pyrolysis device[35]. Among the advantages of this method is fast and cheap analysis. Based on this, useful data on the type of organic matter, total organic carbon, residual potential of the sample, and its thermal breakdown are obtained. In this method, about 70 mg of the sample is powdered, in neutral atmospheric conditions (helium or nitrogen), and the schedule is specified, with a fixed rate of 25 degrees Celsius per minute, and with a temperature of 300 degrees, up to 600 degrees[36]. They heat Celsius. Peak S1 represents free hydrocarbons and peak S2 represents hydrocarbons whose potential to be released after the Flame Ionization Detector (FID) analyzes maturity.

Heating the samples up to 300 degrees Celsius causes free hydrocarbons to evaporate. At a temperature of 300 to 390 degrees Celsius, carboxyl groups are broken in kerogen, a Thermal Conductivity Detector (TCD) analyzes produced CO₂ in the refrigeration cycle, and finally, [37] an S3 catalyst is produced. Next, by increasing the temperature from 300 to 600 degrees Celsius, the molecules in the kerogen are broken, and lead S2 is formed. In the end, what is left is called waste pulp.

The types of S1, S2, and S3 curves resulting from Rockwell analysis are shown in Figure (3-4). In fact, the sum of the carbon values in the oxidation step (S4) and the values explained in the previous step[37], the total amount of organic carbon (TOC) is calculated. Also, during the calibration of the well surveying tool, a weak response may occur compared to the previous state, or the logging tool may get stuck.

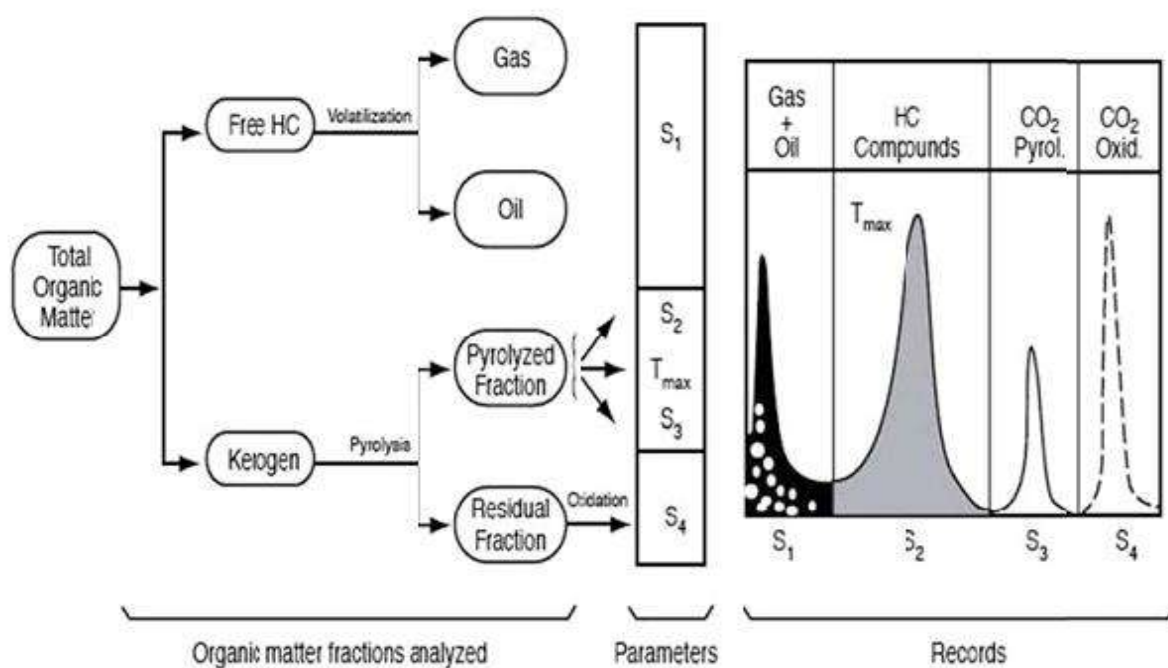


Figure 2-4: Different parts of Rockwell analysis of analyzed rock [50]

In this study, the Rock-Eval. VI pyrolysis method is used (Figure 2-5). Among the most important usable advantages of this model compared to older generations is the very high accuracy in calculating TOC at the maximum temperature T_{max} [40]. Compared to older generations, this device has different detector technology and more accurate temperature control with a wider temperature range. In addition, other hardware changes have been made that increased the accuracy of pyrolysis analysis results.



Figure 2-5: A view of the Rock-Eval VI machine in use

The most important parameters measured by the Rockwell device are:

S1: The powdered samples in the Rockwell device are transferred to an oven filled with helium-neutral gas at a temperature of 200 to 300 degrees Celsius. This amount is actually the free hydrocarbons in the rock powder samples. These samples are under the influence of heat of 300 degrees Celsius, expressed with an increased rate of 5 degrees per minute in the unit of milligrams of hydrocarbons per gram of rock, which are actually free hydrocarbons.

The abundance of free hydrocarbon is known by the FID detector as peak S1 in terms of milligrams of hydrocarbon per gram of rock. Samples with a higher S1 peak value are more mature (Rabbani, 2013). This peak actually consists of hydrocarbons in the range of 1 to 33, which have evaporated at a temperature of 300 °C, and show pollution by drilling mud, so in such a case the S1/S2 ratio is abnormally high. In immature sediments, the rapid breakdown of weakly bonded chemicals causes the presence of a false S1 peak.

S2: In the continuation of the Rockwell pyrolysis process, the temperature increases from 300°C to 550 or 600°C at a rate of 25°C per minute. Due to the increasing in temperature and the thermal pyrolysis of the organic materials of the rock, it is converted into hydrocarbons, and the pyrolysis hydrocarbon, which is known as peak S2 (milligrams of hydrocarbons per gram of rock), which is actually the same amount of hydrocarbons produced during the pyrolysis of kerogen and volatile bitumen. In this range, other compounds, such as oxygenated because of the breakdown of kerogen, and heavy compounds, such as resins and asphaltenes produce the S2 peak, which is a practical and useful parameter for evaluating the production potential in the source rocks.

Tmax: is the maximum thermal value in degrees Celsius where hydrocarbons are formed due to the decomposition of kerogen. In other words, the temperature at which the maximum hydrocarbon is produced due to the decomposition of kerogen. This temperature is formed at the same time as the peak of S2 peak evolution and depends on the type of kerogen and the lithology of the source rock. It is expressed as the maximum temperature and it is an important parameter for evaluating the degree of maturity of organic materials and the source rock sample under study. The maturity range of Tmax. is different according to the types of organic matter. The range of Tmax. changes is limited for type I kerogen while it is wide for type II because of the increase in the structural complexity of organic materials. When the depth and thermal maturity degree of kerogen increases, Tmax increases also, which can be considered as an index of thermal maturity.

S3: The carboxyl groups present in the kerogen of the rock are broken at a temperature of 300 to 390 degrees Celsius and released in the form of CO₂. The IR-CELL detector analyzes these carboxyl groups and is shown them as parameter S3. The number of this peak is presented in milligrams per gram of rock. These parameters express the amount of hydrocarbons in the studied samples for exploratory purposes.

S4: Next, by increasing the temperature of the oxidation furnace up to 850 degrees Celsius at a rate of 20 degrees Celsius per minute, other geochemical parameters of the source rock are measured. Finally, the residual carbon percentage of S4 is calculated by the oxidation system by

the TCD detector. The amount of hydrocarbon in the samples can be expressed in terms of milligrams per gram of rock by calculating the area under the curve of each of the S3, S2, and S1 peaks. The total amount of organic carbon is calculated by measuring the S4 parameter and other values in the oxidation stage [41].

TOC: The amount and percentage of organic matter (hydrocarbon) in the investigated source rock samples are presented in the form of the percentage of total organic carbon. One of the most significant factors in the geochemical analysis measures the full organic carbon amount content in the source rock. The total amount of organic carbon content is one of the most valuable geochemical parameters measured by tools such as Rockwell, which are costly and time-consuming [42].

The amount of organic matter (hydrocarbon) is reported as total organic carbon content or TOC and is expressed as a percentage of the weight of the rock. This parameter is an essential factor in evaluating geochemical analyses for the source rock samples. The TOC parameter is considered the most important and accurate parameter in the geochemical analysis of source rock. One of the most obvious limitations of source rock geochemical analyses is the lack of access to source rock samples at different well depths.

In addition to the mentioned parameters, other parameters (indices) such as production index, reproductive power index, hydrogen concentration, and oxygen index can also be measured and evaluated (Figure 2-6).

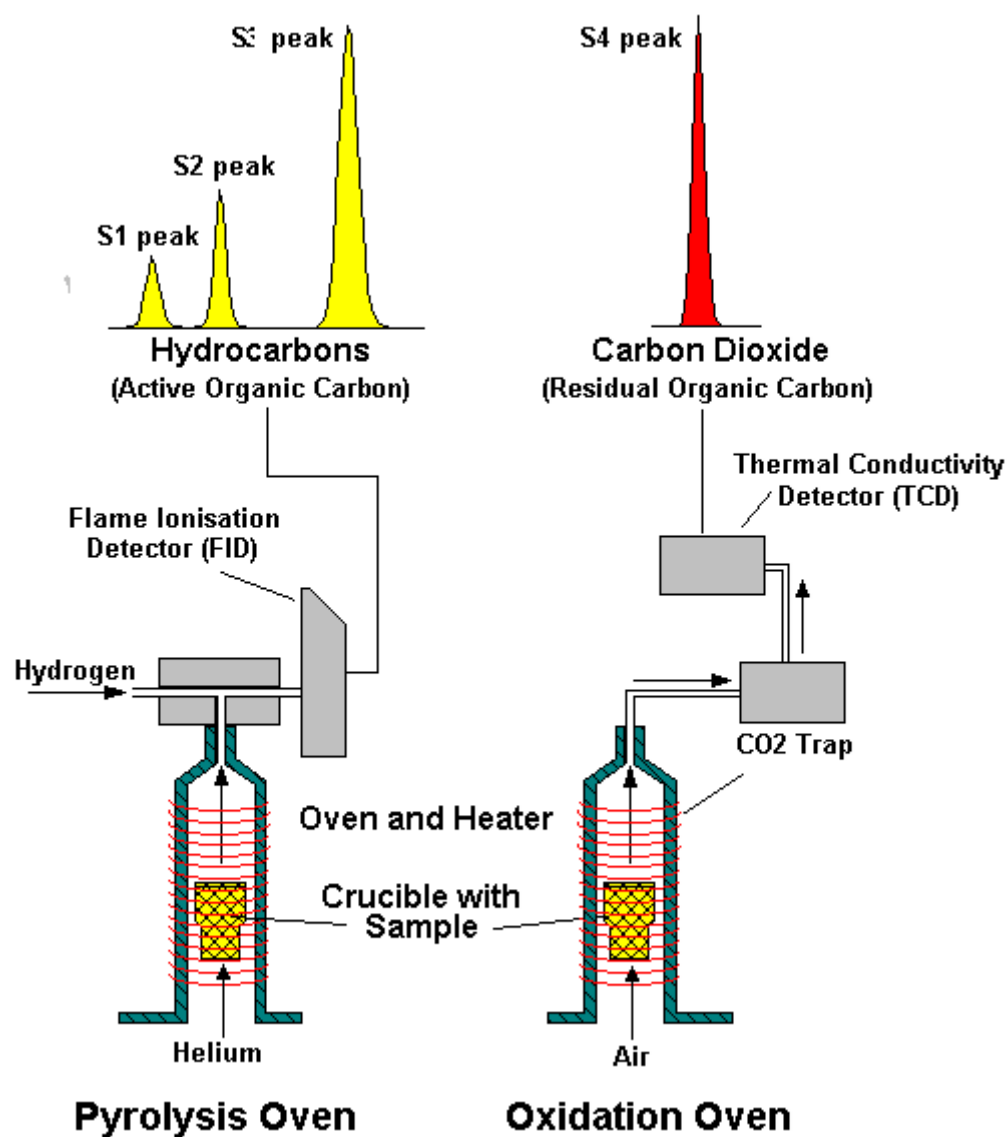


Figure 2-6: Schematic design of the Rockwell device and the components of its oxidation and pyrolysis stages

The method of calculating and measuring these parameters is as follows [43]:

Fertility index: Genetic Potential (GP) is a parameter of the S1+S2 ratio.

Production index or hydrocarbon generation potential (PI): the result of the ratio (S1/S1+S2).

Hydrogen index (HI): S2/TOC ratio in mg HC/g TOC

Oxygen index (OI): S3/TOC ratio in mg CO₂/g TOC

Chapter Three

Results and discussion

3-1- The results of the analysis of Rock Eval 6

After sending the drilling samples to the geochemistry laboratory, the crushed and powdered samples were subjected to Rockwell pyrolysis analysis. The results of Rockwell's analysis of the Mishrif and Zubair formations (upper and lower) and the measured parameters are presented in Table (3-1). Among the most important factors that affect the results of Rockwell analysis are cases such as; contamination of drilling mud with oil-based drilling mud, and hydrocarbon contamination of geological formation debris with hydrocarbons. Therefore, it is necessary to check the validity and accuracy of the analysis results. According to the conditions of geological formations, in terms of depth and degree of maturity, the desired parameters are checked.

In addition, it is necessary to plot the analyzed drilling cuttings in terms of the absence of drilling mud contamination as well as migrated unstable hydrocarbons using the graph of S1 peak changes versus TOC level [44]. This diagram is used to determine the migrated hydrocarbons versus the in-situ hydrocarbons related to the formation (Figure 3-1). The drill bits of the Mishrif Formation are in the range of indigenous hydrocarbon present and do not contain any contamination caused by non-existing hydrocarbons, indicating the lack of influence of migrated hydrocarbons on the results of pyrolysis analysis are Rockwell. Meanwhile, the samples of the Zubair formation (upper and lower) are in the non-indigenous hydrocarbon range and are stained with migrating hydrocarbons and show the effect of non-indigenous hydrocarbons on the results of the analysis.

Another one of the most important indicators that shows the presence of unstable hydrocarbons in the drilling cuttings is the use of the graph of parameter S1 vs. Tmax vs. (low maturity level). In fact, this diagram shows this issue in the samples of parameter S1 as free hydrocarbon (S1), in drilling fragments that have less maturity, they are abnormal and indicate displaced and migrating hydrocarbons. The noteworthy point in the results obtained from the Rockwell analysis in the upper and lower Sarglu formations shows high values of the S1 parameter. Meanwhile, in the lower and upper Sarglu formations, the Tmax parameter varied from 419 to 433, which indicates that the hydrocarbons of these two formations are immature. Therefore, inconsistency in the maturity of organic matter and high values of S1 indicate the level of pollution and the unreliability of this parameter.

In the case that the amount and content of organic matter in the drilling fragments of the studied formations have a sufficient degree of maturity, the S1 parameter is increased and the obtained results are used to evaluate the formation and source rock. The accurate analysis of the amount of hydrocarbons produced in parameter S1 depends on the accurate estimation of the amount of organic matter in the analyzed samples.

The value of Tmax of the analyzed drilling fragments shows that the amount of organic matter in these formations is immature (Table 4-2). In fact, the presence of free hydrocarbons in the studied samples leads to a decrease in the values of this parameter. Therefore, to analyze and interpret the degree of maturity of organic matter, Vitrinab reflection has been used as an index to estimate the estimation of organic matter and Tmax reconstruction. The most important parameters of analysis and interpretation and evaluation of geochemical parameters of possible source rocks are the calculation of parameters such as HI, TOC, and S2. Considering that the maturation process of organic materials results in the production of organic materials and hydrocarbons from the source rock, the judgment regarding the values of the obtained parameters for evaluating and interpreting the geochemistry of the possible source rock may be incorrect and not an accurate interpretation of it (Table 4-3). Therefore, according to the maturity of the organic materials of the upper and lower headwater formations, the initial value of these factors was calculated using common relationships. For this purpose, the following relationships were used:

$$TOC_o = TOC_m + \left(TOC_m * \left(\frac{T_{max} - 435}{30} \right) \right) \quad (1)$$

$$HI_o = HI_m + \left(HI_m * \left(\frac{T_{max} - 435}{30} \right) \right) \quad (2)$$

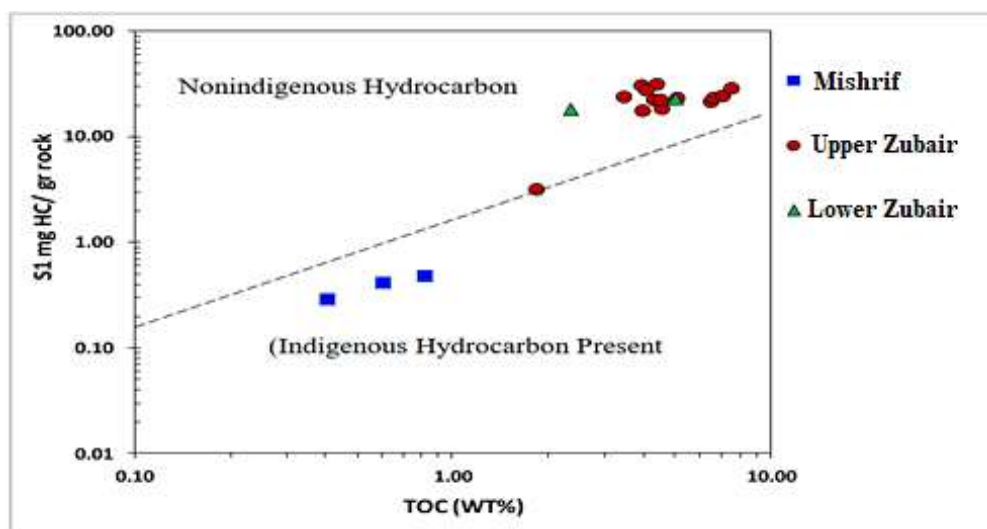


Figure 3-1: S1 parameter changes versus TOC [44]

Table 3-1: Rockeval6 analysis of the Mishrif and Upper Zubair formations for Well Zb-202

WELL	ROCK UNIT (Fm.)	TOP (m)	BOTTOM (m)	TOC (wt. %)	S1 (mgHC/gr Rock)	S2 (mgHC/gr Rock)	S3 (mgCO ₂ /gr Rock)	Tmax	PI	HI (mgHC/gr TOC)	OI (mgCO ₂ /gr TOC)	S1/TOC
Zb-202	Mishrif	2636	2636	0.82	0.49	2.81	1.33	432	0.15	344	163	0.60
		2816	2816	0.40	0.29	0.42	1.12	429	0.41	105	280	0.72
		2870	2874	0.60	0.42	0.79	2.01	438	0.35	131	334	0.70
	Upper Zubair	3020	3020	1.83	3.21	9.10	1.41	419	0.26	497	77	1.75
		3038	3040	4.38	32.04	8.84	0.96	430	0.78	202	22	7.32
		3042	3042	3.91	30.90	6.73	1.03	433	0.82	172	26	7.90
		3046	3048	3.45	24.18	6.27	0.88	430	0.79	182	26	7.01
		3056	3058	4.04	28.17	6.70	1.04	432	0.81	166	26	6.98
		3064	3066	5.07	23.47	15.54	1.29	428	0.60	307	25	4.63
		3068	3070	4.28	22.63	12.35	1.30	431	0.65	289	30	5.29
		3074	3076	4.53	18.70	12.56	1.14	428	0.60	277	25	4.13
		3078	3080	3.93	17.83	8.00	1.20	428	0.69	204	31	4.54
		3082	3084	6.45	21.91	22.59	1.32	425	0.49	350	20	3.40

Table 3-2: Rockeval6 analysis of the Upper and Lower Zubair formations for Well Zb-202

WELL	ROCK UNIT (Fm.)	TOP (m)	BOTTOM (m)	TOC (wt. %)	S1 (mgHC/gr Rock)	S2 (mgHC/gr Rock)	S3 (mgCO ₂ /gr Rock)	Tmax	PI	HI (mgHC/gr TOC)	OI (mgCO ₂ /gr r TOC)	S1/TOC
Zb-202	Upper Zubair	3086	3088	6.60	23.63	26.75	1.34	424	0.47	405	20	3.58
		3090	3092	7.05	24.89	29.91	1.30	421	0.45	424	18	3.53
		3094	3096	4.48	22.62	15.00	0.84	426	0.60	335	19	5.05
		3100	3102	7.51	29.05	29.48	1.26	422	0.50	393	17	3.87
	Lower Zubair	3160	3162	2.34	18.47	2.71	0.82	434	0.87	116	35	7.89
		3167	3167	5.00	23.12	10.25	0.95	432	0.69	205	19	4.62

Table 3-3: TOC, S2, HI, and Tmax parameters of Mishrif and Zubair Formations

WELL	ROCK UNIT (Fm.)	Tmax Estimate	TOC Initial (Immature)	S2 Initial (Immature)	HI Initial (Immature)
Zb-202	Mishrif	433	-	-	-
		433	-	-	-
		433	-	-	-
	Upper Zubair	438	2.01	11.01	547
		438	4.81	10.70	222
		438	4.30	8.14	189
		438	3.79	7.59	200
		438	4.44	8.11	183
		438	5.58	18.80	337
		438	4.71	14.94	317
		438	4.98	15.20	305
		438	4.32	9.68	224
		438	7.10	27.33	385
		438	7.26	32.37	446
		438	7.76	36.19	467
		438	4.93	18.15	368
		438	8.26	35.67	432
	Lower Zubair	438	2.57	3.28	127
		438	5.50	12.40	226

3-2- The primary results of Rockeval6 pyrolysis

The results of statistical parameters of Rockwell analysis of source rock samples are in Table (4-4).

The highest and lowest amount of free hydrocarbon parameter (S_1), lower and upper Mishrif and Zubair formations are presented in Table (4-4). In addition, the amount of parameter changes with respect to depth is shown in Figure (4-2). If the value of the T_{max} parameter of each of the samples with a high amount of hydrocarbon is low, it indicates that the value of S_1 is false.

Table 3-4: Results of statistical parameters of Rockwell analysis of source rock for Mishrif and Zubair Formations

Formation	Min. S_1	Max S_1	Ave. S_1
Mishrif	0.29	0.49	0.4
Upper Zubair	3.21	32.0	23.09
Lower Zubair	18.47	23.12	20.79

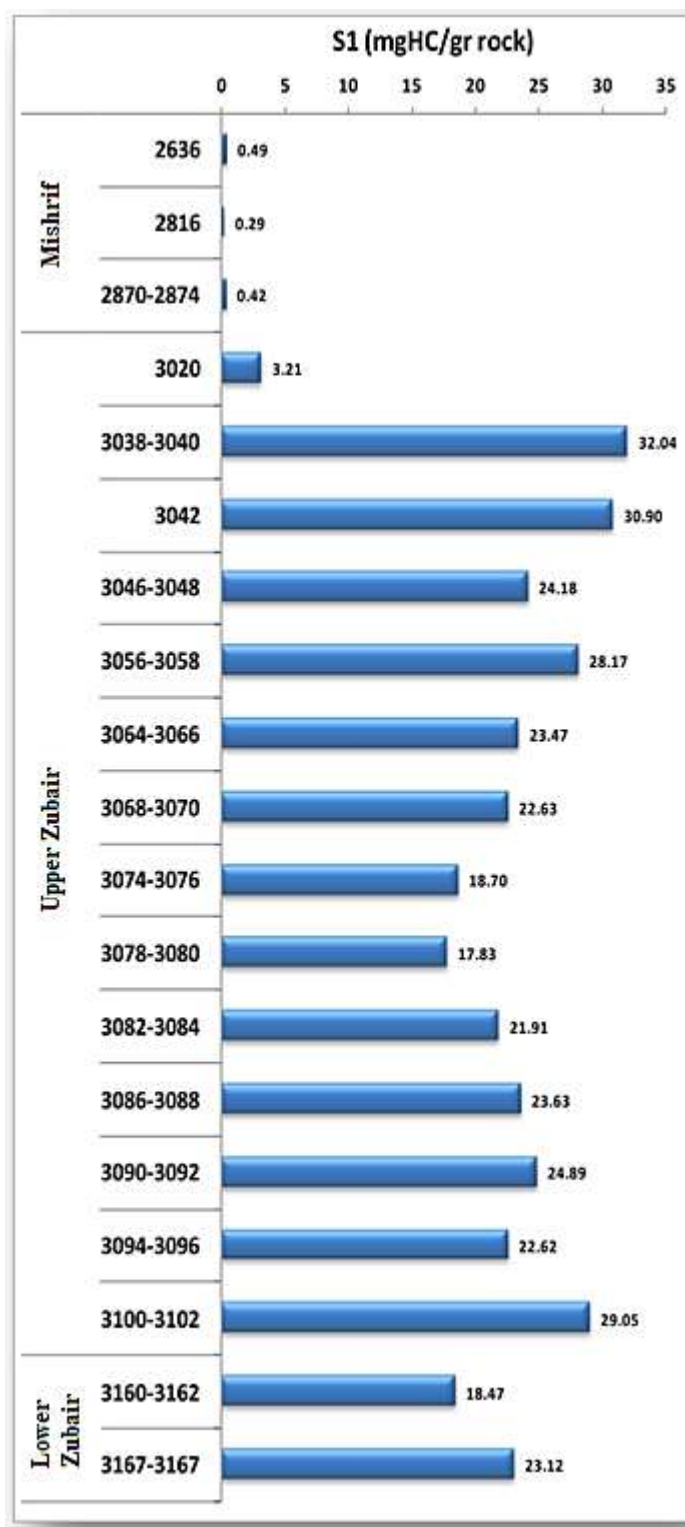


Figure 3-2: S1 parameter variation chart, relative to depth in the source rocks under study

The highest and lowest amount of kerogen and free heavy bitumen (parameter S₂) in the mature samples in the studied formations, and the immature values of the lower and upper Zubair formations are shown in Tables (3-5) and (3-6) and Figure (3-3).

Table 3-5: The highest and lowest value of S₂ parameter in mature source rock samples

Formation	S ₂ Present (Mature) (mgHC/gr rock)		
	Min. S ₂	Max S ₂	Ave. S ₂
Mishrif	0.42	2.81	1.34
Upper Zubair	6.27	29.48	14.99
Lower Zubair	2.71	10.25	6.48

Table 3-6: The highest and lowest values of the S₂ parameter in immature rock samples

Formation	S ₂ Initial (Immature) (mgHC/gr rock)		
	Min. S ₂	Max S ₂	Ave. S ₂
Upper Zubair	7.59	35.67	18.13
Lower Zubair	3.28	12.4	7.84

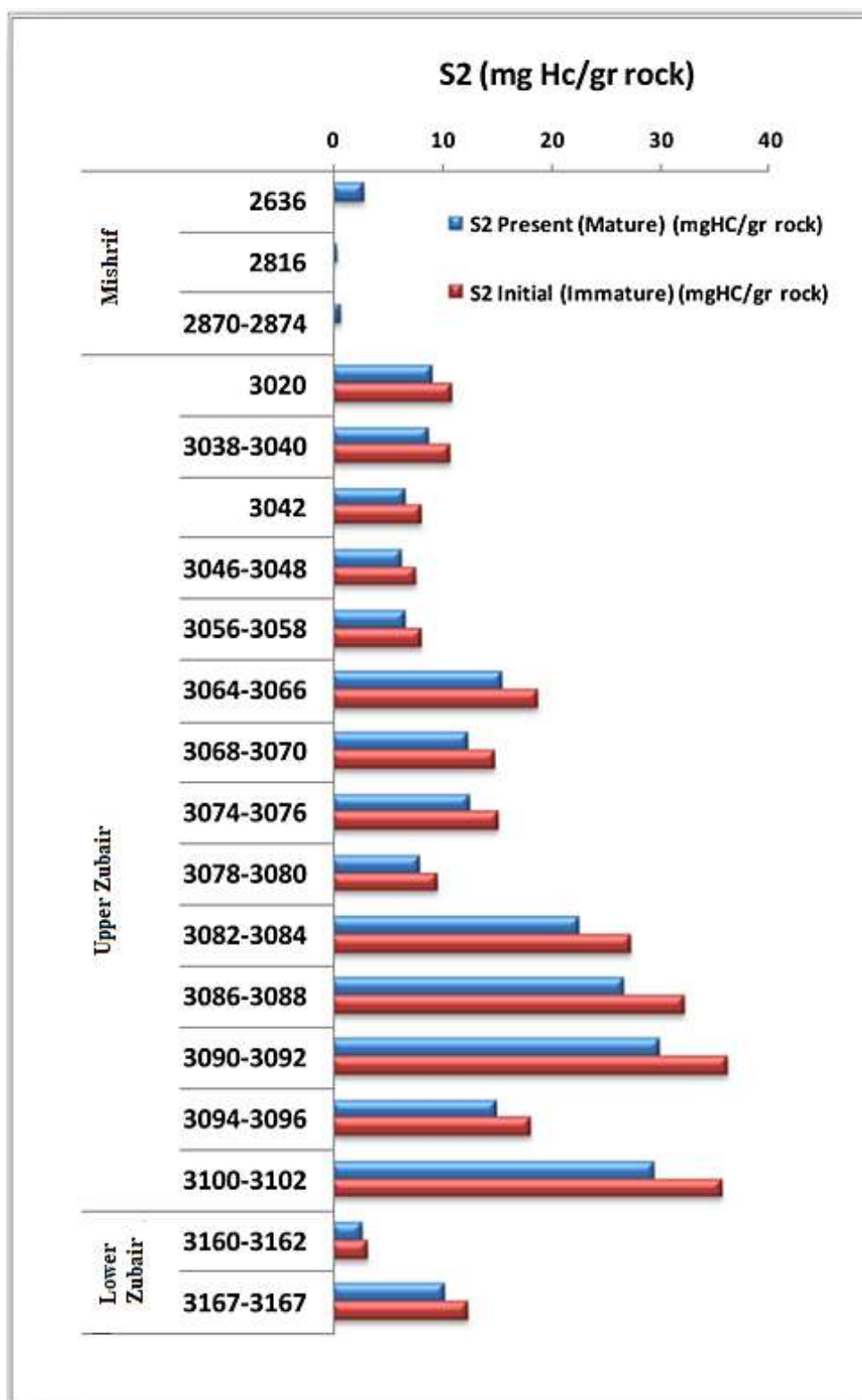


Figure 3-3: Bar chart of S2 parameter in the source rock samples studied

Table 3-7: Statistical parameters of oxygenated compounds and carboxyl group S3

Formation	Min. S3	Max S3	Ave. S3
Mishrif	1.12	2.01	1.49
Upper Zubair	0.84	1.41	1.17
Lower Zubair	0.82	0.95	0.88

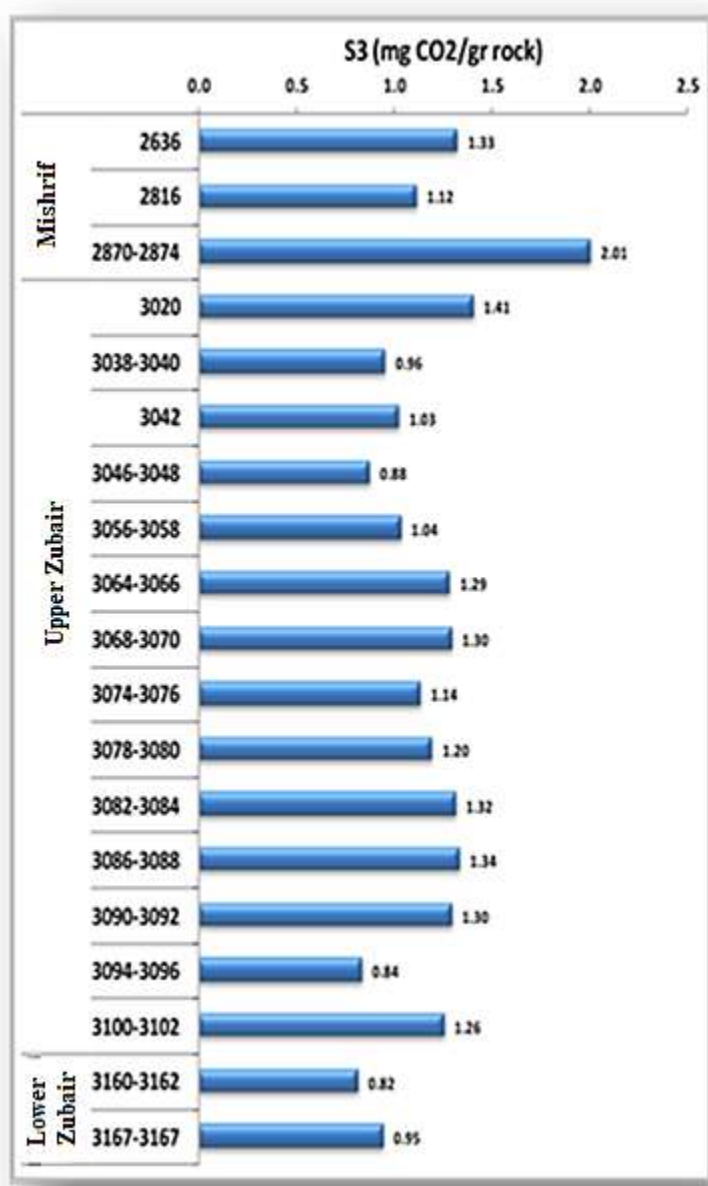


Figure 3-4: Bar chart of S3 parameter in the source rock samples studied

The minimum and maximum values of total organic carbon (TOC parameter) in mature samples in the source rocks studied and the values of immature samples in the lower and upper Zubair Formation are presented in tables (3-8 and 3-9). In addition, the number of changes of this parameter with respect to the depth shown in Figure (3-5).

Table 3-8: The highest and lowest total organic carbon (TOC) parameters in mature samples

Formation	TOC Present (Mature) (WT%)		
	Min. TOC	Max.TOC	Ave. TOC
Mishrif	0.4	0.82	0.61
Upper Zubair	1.83	7.51	4.82
Lower Zubair	2.34	5	3.67

Table 3-9: The highest and lowest total organic carbon (TOC) parameters in immature samples

Formation	TOC Initial (Immature) (WT%)		
	Min. TOC	Max.TOC	Ave. TOC
Upper Zubair	2.01	8.26	5.3
Lower Zubair	2.57	5.5	4.04

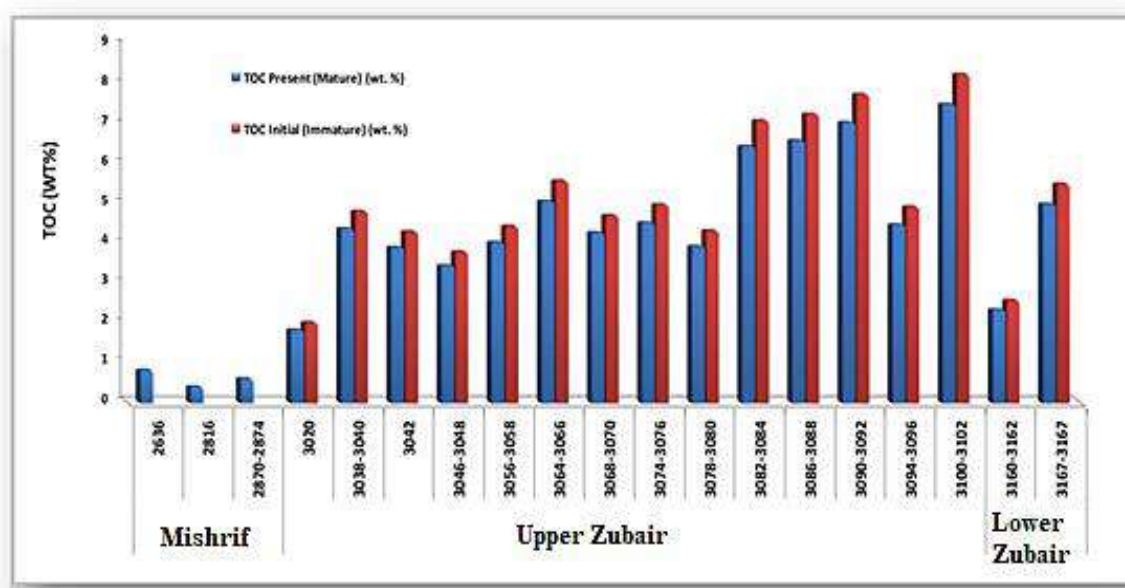


Figure 3-5: Bar graph of TOC in the source rock samples studied

The highest and lowest values of the hydrogen index parameter (HI), Bala samples of both source rocks under study, and immature samples of lower and upper Zubair Formation are shown in tables (3-10) and (3-11). In addition, the graph of changes in this parameter with respect to depth shown in Figure (3-6).

Table 3-10: The lowest and highest values of the HI parameter in mature samples

Formation	HI Present (Mature) (mgHC/gr TOC)		
	Min. HI	Max HI	Ave. HI
Mishrif	105	344	193
Upper Zubair	166	497	300
Lower Zubair	116	205	160

Table 3-11: The lowest and highest values of the HI parameter in immature samples

Formation	HI Initial (Immature) (mgHC/gr TOC)		
	Min. HI	Max HI	Ave. HI
Upper Zubair	183	547	330
Lower Zubair	127	226	176

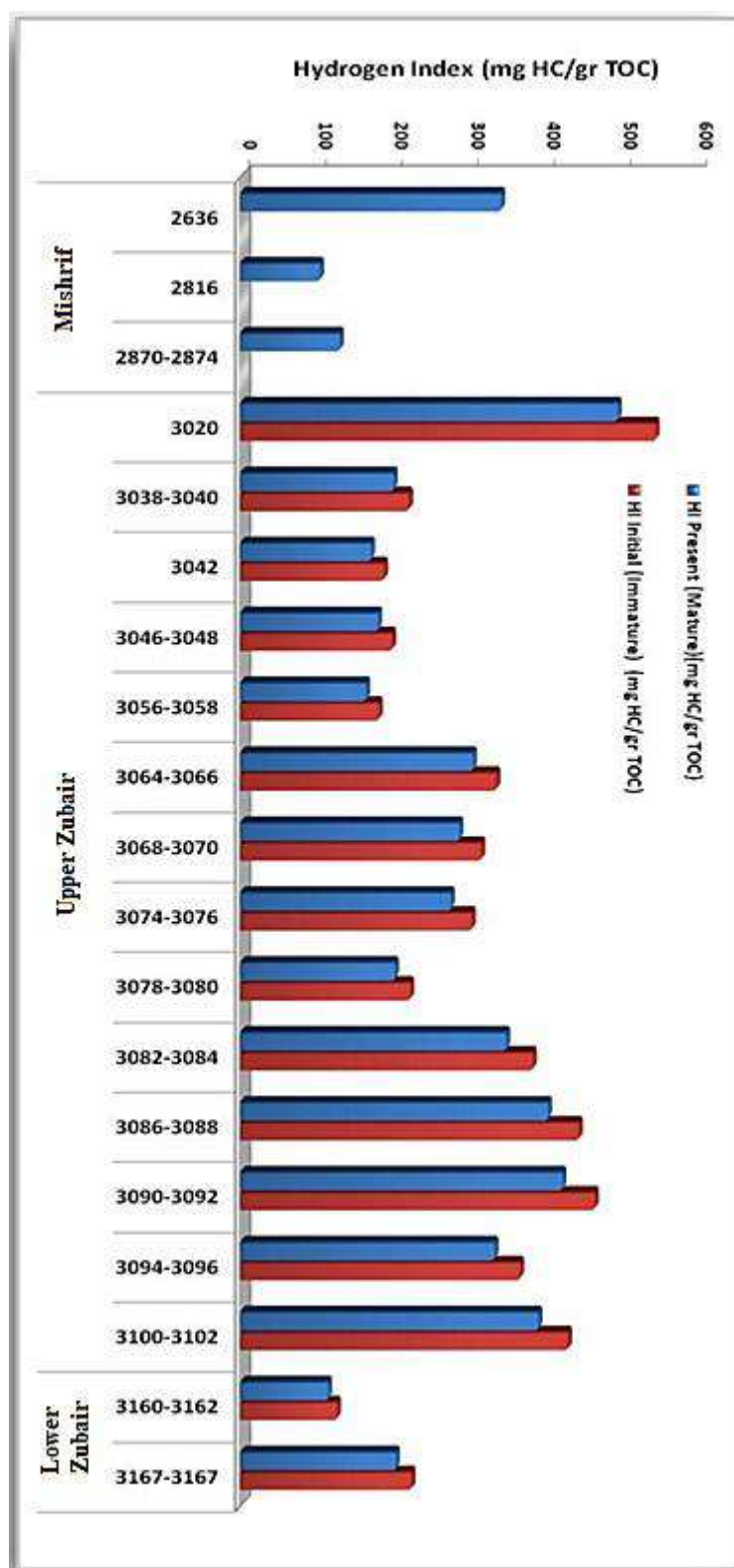


Figure 3-6: bar chart of HI for Mishrif, lower and upper Zubair Formations

Table (3-12) shows the highest and lowest values of HI and OI of mature samples of Mishrif and lower and upper Zubair Formations. In addition, the changes in these parameters with respect to depth shown in Figure (3-7).

Table 3-12: The lowest and highest values of HI and OI in mature samples of Mishrif, lower and upper Zubair Formations

Formation	HI Present (Mature) (mgHC/gr TOC)			OI Present (Mature) (mgHC/gr TOC)		
	Min. HI	Max HI	Ave. HI	Min. OI	Max OI	Ave. OI
Mishrif	105	344	193	163	334	259
Upper Zubair	166	497	300	17	77	24
Lower Zubair	116	205	160	19	35	27

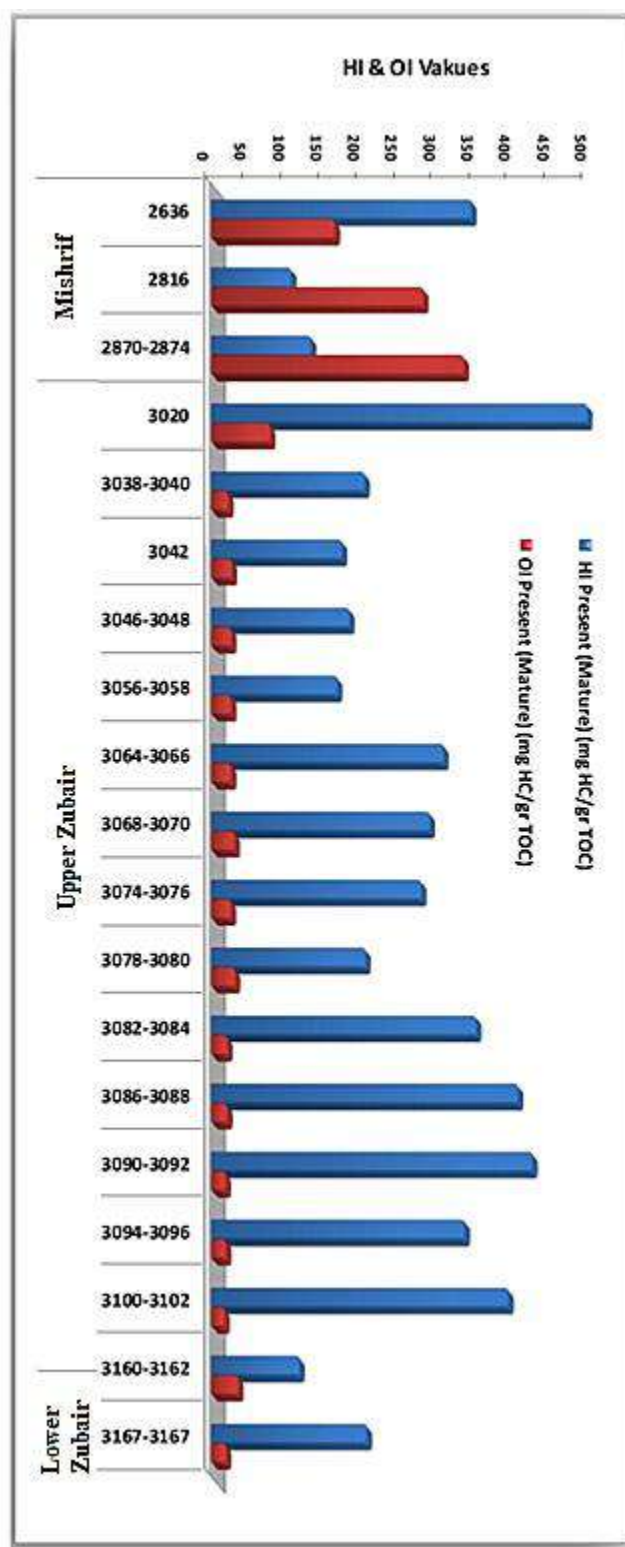


Figure 3-7: Bar chart of HI and OI values of Mishrif, lower and upper Zubair Formations

3-3- Assessment of organic matter

Among the most significant factors in the assessment of the source rock is the detection of the type of kerogen, which plays a very important role in controlling the type of hydrocarbon. The type of hydrocarbon produced from the source rock depends on the hydrogen content of the source rock's organic matter. It is possible to determine the type of kerogen by using the results obtained from Rockwell analysis, including the diagram of the parameter HI versus OI in the source rock.

The value of each of the presented parameters presented in Table (4-11). HI vs. OI diagram shows type III kerogen and a small amount of type II in samples of the Mishrif Formation and type II kerogen in the lower and upper Zubair Formation (Figure 4-12).

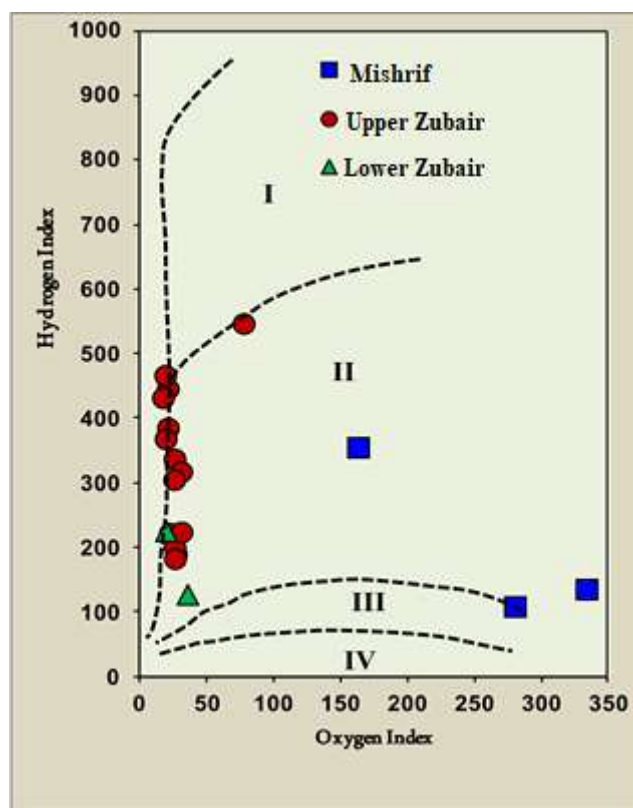


Figure 3-8: Kerogen type determination diagram using HI vs. OI diagram of Mishrif, lower and upper Zubair Formations.

According to the classification of kerogen type using the HI values in Table (4-15) and Figure (4-13), the OI index of Mishrif formation samples indicates type III kerogen. In addition, the values

of the HI parameter in the lower Zubair formation show both kerogen types III and II, and the upper Zubair formation shows the majority of type II kerogen and a small amount of type III.

Table 4-15: Geochemical parameters describing the type of produced hydrocarbon and kerogen type [45]

Kerogen	HI(mg HC/ gr TOC)	S2/ S3	Atomic H/C	Main product at peak maturity
I	> 600	>15	>1.5	Oil
II	300- 600	10-15	1.2- 1.5	Oil
II/III	200-300	5-10	1- 1.2	Oil/ Gas
III	50-200	1-5	0.7-1	Gas
IV	<50	<1	< 0.7	None

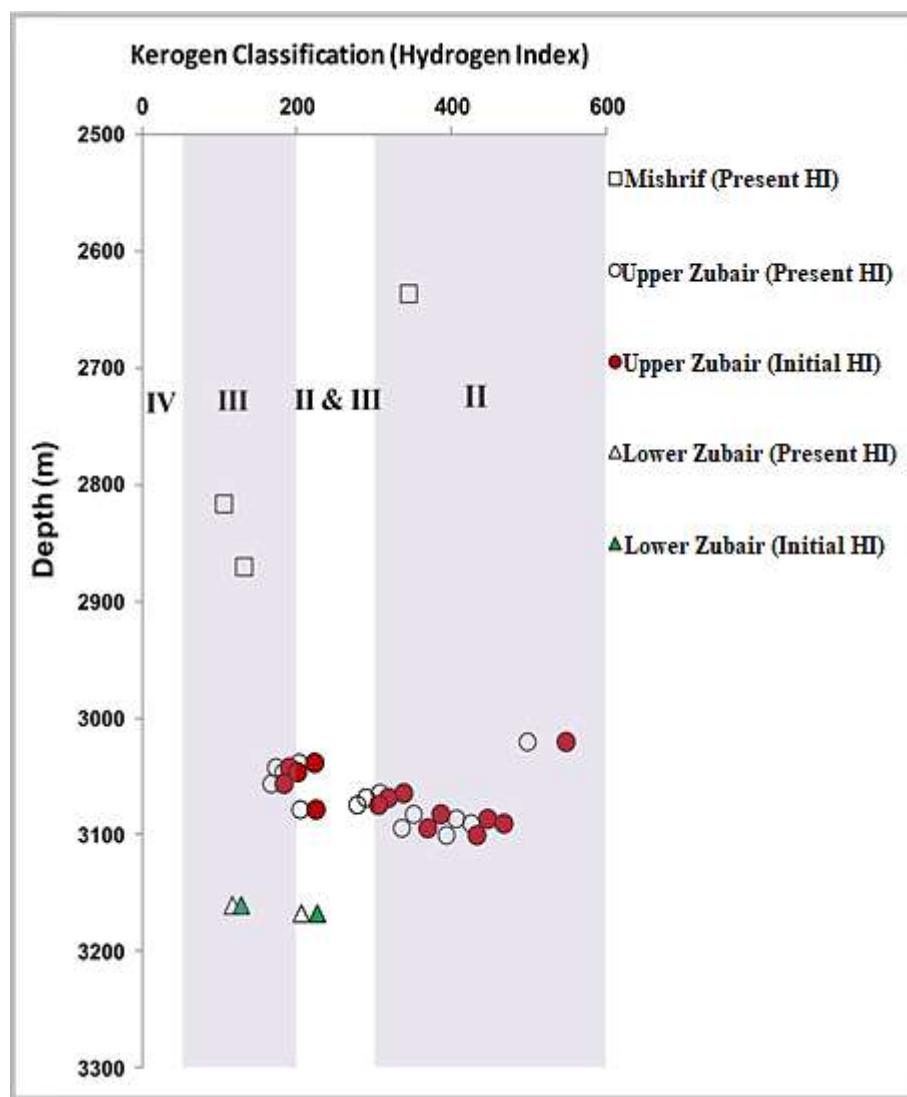


Figure 3-9: The graph of HI changes against the depth of the samples taken in the evaluation of the type of kerogen of the Mishrif, upper and lower Zubair Formations.

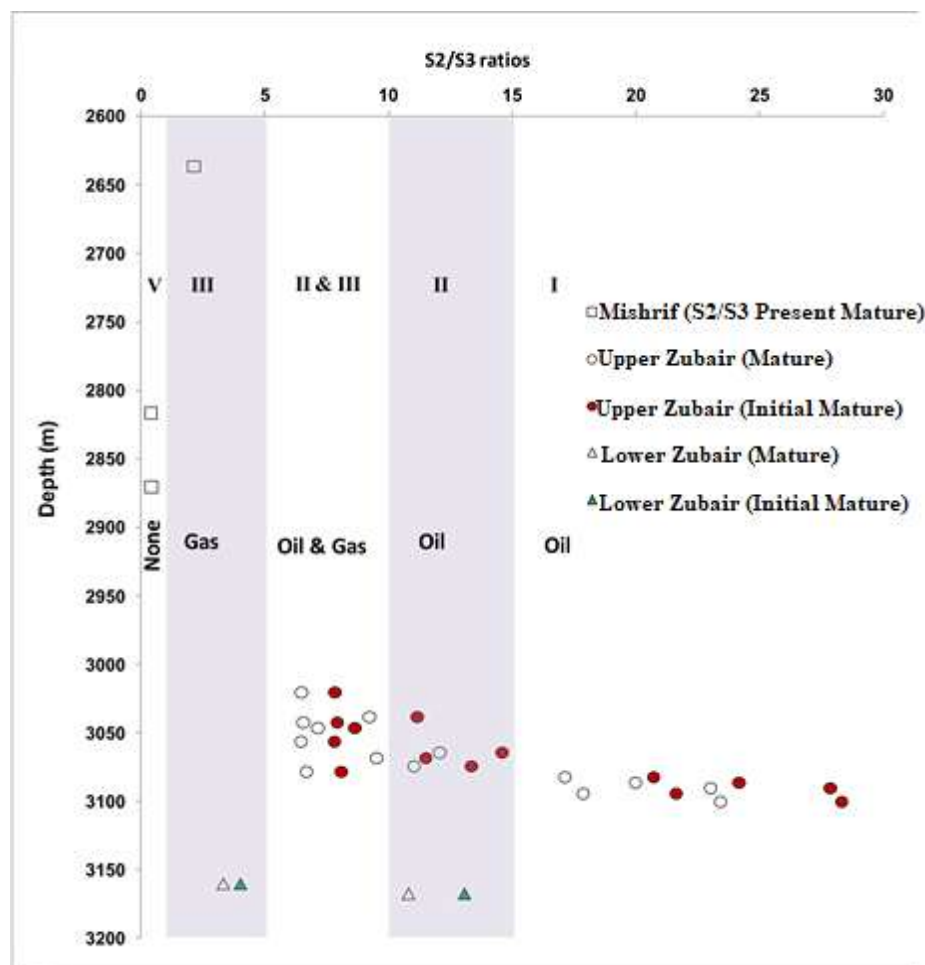


Figure 3-10: Chart of kerogen determination using S2/S3 parameter of Peters and Casa (1994).

For further assurance and investigation, the interpretations made with the HI versus Tmax graph have been used (Espitalié et al., 1985) [46]. This diagram shows the type of kerogen in the studied formations. This diagram shows type II kerogen for the upper Zubair, and the lower Zubair formation contains type II and a lesser amount of type III. Examining the samples of Mishrif and Zubair Formations shows kerogen type III (Figure 4-15).

Chapter Four

Conclusion and Recommendations

4-1- Conclusions

The results obtained from the pyrolysis geochemical analysis of Rockwell from the Mishrif, Lower, and Upper Zubair Formations indicate type III and II kerogens and a small amount of type III and II/III respectively (Table 5-1).

Table 5-1: Pyrolysis geochemical analysis of Rockwell from the Mishrif, Lower, and Upper Zubair Formations

Formation	Kerogen Type
Mishrif	III
Upper Zubair	III II
Lower Zubair	II/III

From the point of view of hydrocarbon generation, the studied formations have the characteristics described in table (2-5) as possible source rocks.

Table 5-2: Potential hydrocarbon generation of studied Formations

Formation	Hydrocarbon Generation Potential
Mishrif	Poor
Upper Zubair	Good-Excellent
Lower Zubair	Fair-Very Good

The obtained rock-well data indicate that the organic matter content of the Mishrif Formation is immature, while the upper and lower Zubair Formations are mature. The results obtained from the vitrinite reflectance values of the studied samples confirm the results obtained from Rockwell pyrolysis. Based on the results obtained from Rockwell, the Mishrif Formation has no important role in the production of hydrocarbons in the reservoirs due to the low enrichment of organic materials and the immature nature of these organic materials.

Considering the magnitude of Rag-I parameters and the degree of maturity of the organic matter content of these Formations, accepting the production of this amount of hydrocarbon (S1) in these two Formations is questionable. That is due to the relatively low thermal maturity (the beginning of the oil-generating window) of these Formations because of the amount of free hydrocarbon along with high hydrocarbon production (current values of S2) in these Formations.

4-2- Recommendations

According to the geological location of the studied oil field, it seems to be another origin rock as another origin rock. Therefore, it is suggested to carry out a more detailed investigation into other stones of possible origin.

It is suggested that for the connection between source rock formations and reservoir rocks, it is necessary to carry out more accurate isotopic analyzes.

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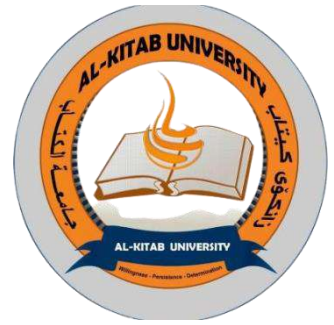
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**University of AL-Kitab
College of Engineering
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Department**



Production Optimization in an Inverted Five-Spot Waterflooding Reservoir

A Project Submitted to the College of Engineering
University of AL-Kitab in Partial Fulfillment
of Requirements for the Degree of
B.Sc. in Petroleum Engineering

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Abstract

Effective management of oil reservoirs is critical for maximizing hydrocarbon recovery and mitigating production decline associated with natural pressure depletion. This study evaluates and optimizes production strategies in a multi-well black-oil reservoir using the CMG IMEX numerical simulator. The primary objective is to comparatively analyze reservoir performance under two main scenarios: natural depletion and secondary recovery via water injection.

A 3D numerical model was constructed featuring an inverted five-spot pattern consisting of one central injection well and multiple production wells. The simulation results demonstrated that relying solely on natural depletion led to a rapid reduction in average reservoir pressure, prompting premature well shut-ins when the bottom-hole pressure reached the operational minimum limit of 1500 psi. Under this scenario, cumulative oil production was restricted to 10.64 MMSTB, yielding a low recovery factor (RF) of 4.4% by 1993.

Conversely, the implementation of a continuous water injection strategy (6,000 barrels of water per day) initiated in 1985 effectively arrested the pressure decline. This pressure maintenance stabilized well deliverability and prevented early shutdowns. Consequently, by the end of the evaluation period in 2020, cumulative oil production significantly increased to 32.14 MMSTB, enhancing the ultimate recovery factor to 13.3%—an improvement of over 2.6 times compared to the depletion case. Furthermore, the water-oil ratio (WOR) remained within acceptable operational bounds, indicating efficient sweep and controlled displacement.

In conclusion, the study quantitatively validates that early implementation of water injection is a technically robust strategy to sustain reservoir pressure, optimize well productivity, and substantially extend the economic life of multi-well oil fields.

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CHAPTER ONE

INTRODUCTION

1.1 Introduction

Oil reservoirs are complex geological systems where the movement of fluids is governed by the interplay of rock properties, fluid characteristics, and the conditions under which operations take place. Effective management of these reservoirs is crucial for optimizing hydrocarbon extraction and maintaining sustainable production throughout the life of the field. As reservoirs age, natural pressure within them decreases, and production capabilities usually decline, potentially leading to a considerable drop in oil recovery unless a pressure support system is put in place.

Reservoir simulation has emerged as one of the most effective tools in petroleum engineering for analyzing reservoir behavior and forecasting production performance under various operational strategies. Reservoir simulation enables engineers to examine intricate multi-phase flow systems and assess various development scenarios by modeling fluid flow and reservoir characteristics within a numerical framework, prior to implementing these scenarios in actual field activities. A widely used technique for maintaining reservoir pressure and enhancing oil extraction is the injection of water. Water injection offers assistance by creating pressure and enhancing the movement of oil toward production wells, which leads to improved sweep efficiency and an increase in total oil production. The success of these methods, however, greatly relies on the characteristics of the reservoir, the arrangement of wells, and operational limitations.

In reservoirs with several production wells, the way these wells interact significantly influences the total output performance. Consequently, improving

production methods in multi-well systems necessitates thorough examination of pressure distribution, well locations, injection rates, and operational constraints.

In recent years, numerical simulators like CMG IMEX have become popular tools for assessing strategies for managing reservoirs. These simulators allow engineers to create accurate reservoir models, test various production situations, and examine the effects of pressure support methods like water injection. This research centers on optimizing production in a multi-well oil reservoir through the use of CMG IMEX simulation. It specifically highlights the assessment of the impact of water injection on maintaining reservoir pressure, enhancing oil production performance, and improving the recovery factor.

1.2 Problem Statement

Numerous oil reservoirs undergo a notable decrease in pressure during extraction, especially when depending exclusively on the natural energy of the reservoir. The decrease in pressure can cause a decline in well productivity, premature well shut-ins, and ultimately lower recovery rates.

In reservoirs with multiple wells, the scenario becomes more complicated because of the interactions among the wells and the irregular distribution of pressure within the reservoir. Without effective pressure maintenance methods, production efficiency may decrease quickly, leading to ineffective hydrocarbon extraction.

Water injection is commonly employed as a secondary recovery technique to sustain reservoir pressure and enhance sweep efficiency. Nonetheless, the success of water injection relies on various factors, such as reservoir differences, well design, operational limitations, and injection methods.

Thus, it is essential to assess how various production strategies affect reservoir performance and to find out if maintaining pressure through water injection can greatly enhance production results.

This study tackles this issue by utilizing reservoir simulation methods to investigate production patterns in a multi-well oil reservoir and assess the efficiency of water injection as a means of providing pressure support.

1.3 Objectives of the Study

The primary goal of this research is to assess and improve oil production efficiency in a multi-well reservoir by employing numerical reservoir simulation techniques.

The particular aims of the research are as follows:

- ❖ Creating a numerical model for reservoir simulation with CMG IMEX.
- ❖ Assessing the performance of the reservoir in situations of natural depletion.
- ❖ Examining the impact of water injection on maintaining reservoir pressure.
- ❖ Analyzing the production performance in both depleting and water injection situations.
- ❖ Examining how water injection affects total oil production and the recovery factor.
- ❖ Predicting how a reservoir will perform in terms of production over an extended period.

1.4 Scope of the Study

The goal of this study is to evaluate CMG IMEX black-oil simulator-based strategies for increasing production in a synthetic multi-well oil reservoir model.

Building a numerical model of the reservoir helps to show the geological characteristics and fluid properties of a typical oil reservoir in the study. Arranged in an inverted five-spot pattern, the model comprises a main water injection well together with multiple production wells

Two main production scenarios are evaluated.:

1. Natural depletion occurs when the reservoir is drained without assistance from external pressure.
2. Water injection involves the process of introducing water to sustain reservoir pressure and improve the extraction of oil.

Operational limitations, including the minimum bottom-hole pressure required for production wells and the steady injection rates for the injection well, are implemented to replicate realistic operational conditions in the field.

The results of the simulation are examined concerning the behavior of reservoir pressure, total oil production, trends in water production, and the recovery factor. Additionally, the performance of production is projected for a future timeframe that goes up to the year 2030.

Chapter Two

Literature review

2.1 Overview of reservoir simulation in petroleum engineering

Reservoir simulation is the numerical representation of fluid flow and transport in porous media, used to forecast production under alternative operating and development scenarios. Unlike purely analytical methods (e.g., material balance or decline-curve analysis), reservoir simulation explicitly represents spatial heterogeneity and the coupled, nonlinear physics of multiphase flow, making it suitable for complex reservoirs and multi-well interactions (Aziz & Settari, 1979; Gerritsen & Durlofsky, 2005).

2.1.1 Why reservoir simulation is used

- Forecast oil, gas, and water production under different development plans and well constraints.
- Quantify the impact of uncertainty and heterogeneity on sweep efficiency, breakthrough, and recovery factor.
- History match to production data to improve confidence in forecasts and support decision-making.
- Evaluate secondary and tertiary recovery processes (water flood, miscible injection, polymer, etc.) and compare alternatives.
- Support optimization workflows by enabling repeatable evaluation of candidate control/placement scenarios.

2.1.2 Types of reservoir models and simulators

Reservoir models vary by level of physics and computational cost. Common categories include:

- Black-oil models: represent oil, gas, and water phases with solution gas in oil and vaporized oil in gas approximations; widely used for field-scale forecasting and waterflood design (Aziz & Settari, 1979).
- Compositional models: track multiple hydrocarbon components and phase behavior rigorously; used for miscible gas injection and condensate reservoirs.
- Thermal models: include energy balance and temperature-dependent properties; used for steam flooding and heavy oil recovery
- Unconventional/fractured reservoir models: incorporate hydraulic fractures, dual-porosity/dual-permeability, and non-Darcy effects where appropriate.

2.1.3 Typical reservoir simulation workflow

A practical simulation study is iterative and multidisciplinary. A commonly adopted workflow consists of:

1. Data integration: gather static (structure, facies, porosity, permeability) and dynamic (PVT, relative permeability, well tests, production history) data.
2. Geological and grid model: construct a 3D model and select an appropriate gridding approach (corner-point, Cartesian, local grid refinement).
3. Fluid and rock functions: define PVT tables, rock compressibility, relative permeability and capillary pressure curves.
4. Initialization: set initial pressures, saturations, contacts, and aquifer support if relevant.
5. Well and facility representation: define well locations, completions, constraints, and (when needed) coupling to wellbore models or surface networks.
6. History matching: adjust uncertain parameters (e.g., permeability multipliers, fault transmissibility, skin) to reproduce historical pressures and rates.
7. Forecasting and scenario analysis: simulate alternative controls, patterns, and development options; compute KPIs such as cumulative oil and NPV.

8. Sensitivity/uncertainty analysis: quantify which uncertain parameters most impact objectives and risks.

As simulation models become larger and more detailed, computational performance and numerical stability become critical, motivating robust nonlinear solvers, preconditioning, and parallelism (Chen, Huan, & Ma, 2006).

2.2 Fundamental Principles of Reservoir Performance and Productivity

2.2.1 Conservation laws and Darcy flow

The governing equations of reservoir simulation arise from conservation of mass for each component (or phase) and constitutive flow relations. For single-phase flow, Darcy's law relates volumetric flow rate to the pressure gradient:

$$q = -(kA/\mu) (\Delta P/\Delta X) \dots \dots \dots (2.1)$$

where q is flow rate, k is permeability, A is cross-sectional area, μ is viscosity, and $\Delta P/\Delta X$ is the pressure gradient. For multiphase flow, relative permeability modifies phase mobility, and capillary pressure links phase pressures. In field reservoirs, heterogeneity in permeability and porosity leads to preferential flow paths and early breakthrough, strongly influencing recovery (Dake, 1978; Gerritsen & Durlofsky, 2005).

2.2.2 Drive mechanisms and reservoir energy

Reservoir performance depends on the dominant drive mechanism supplying energy for production, including solution-gas drive, gas-cap expansion, water drive, compaction drive, and combinations. Drive mechanisms affect pressure decline behavior, gas-oil ratio evolution, water cut, and ultimate recovery factor. Secondary recovery (water or gas injection) maintains pressure and improves sweep, while tertiary (EOR) methods alter fluid properties or mobilize residual oil.

2.2.3 Well productivity, inflow performance, and deliverability

Well productivity is commonly summarized using the productivity index (PI), which assumes a linear relationship between oil rate and drawdown. For solution-gas drive reservoirs, the relationship is typically nonlinear due to two-phase flow near the wellbore. Vogel (1968) proposed an empirical inflow performance relationship (IPR) widely used to estimate rates as a function of flowing bottom-hole pressure in saturated oil reservoirs.

Near-well representation in simulation requires a well model that links grid-block pressure to wellbore pressure and rate. The widely used Peaceman well model provides a consistent definition of the well index (WI) for finite-difference grids, relating well flow to pressure difference between the well and the grid block (Peaceman, 1978).

Key factors controlling well productivity

- Permeability and anisotropy (k_h , k_v): higher permeability and better vertical connectivity generally improve productivity.
- Skin and damage/stimulation: positive skin reduces deliverability; negative skin (stimulation) increases it.
- Completion interval and net pay: longer effective perforated interval increases inflow area.
- Multiphase effects: relative permeability endpoints and mobility ratio affect PI and IPR curvature.
- Operating constraints: minimum bottom-hole pressure, maximum drawdown, and facility limits bound achievable rates.

2.2.4 Water flood performance and multi-well interaction

In multi-well systems, production depends not only on individual well productivity but also on sweep efficiency and pressure support created by injection patterns. Water flood performance is influenced by areal and vertical sweep,

mobility ratio, well spacing, heterogeneity, and pattern configuration. Optimizing multiple wells is therefore inherently a field-scale problem: changes in one well's constraints can redistribute flows, alter inter well pressure gradients, and shift breakthrough timing across the pattern.

2.3 Introduction to Production Optimization Concepts

2.3.1 Definition and objectives

Production optimization is the process of selecting decision variables (controls and/or design variables) to maximize or minimize an objective while satisfying operational, geological, and facility constraints. In reservoir management, objectives commonly include maximizing NPV, maximizing cumulative oil, minimizing water production or CO₂ usage, or balancing multiple goals in a multi-objective setting (Hou et al., 2015; Jansen, 2011).

2.3.2 Decision variables in multi-well optimization

Common decision variables include:

- Well controls: time-varying rates and/or bottom-hole pressures for producers and injectors.
- Well placement and trajectories: surface locations, targets, horizontal length, and azimuth.
- Completion and stimulation design: perforation intervals, ICD/ICV settings, fracture half-length and conductivity (for fractured wells).
- Facility and operational settings: injection allocation, lift constraints, and water-handling limits.

2.3.3 Optimization problem formulation

A simplified mathematical statement of the optimization problem is:

Maximize $J(u)$ subject to $g(u) \leq 0$, $h(u) = 0$, and $u^- \leq u \leq u^+$

where u represents the vector of decision variables (e.g., well BHPs over time), J is the objective (e.g., NPV), and constraints represent physical, operational, and regulatory limits (e.g., maximum water cut, minimum BHP, facility caps). Because J is evaluated through a nonlinear simulator, the problem is typically high-dimensional, nonconvex, and expensive.

2.3.4 Optimization approaches used with reservoir simulators

Two broad families of approaches dominate the literature:

- Gradient-based methods (adjoint): compute gradients efficiently with respect to many controls and can converge rapidly for smooth problems; widely discussed in adjoint-based reservoir control literature (Jansen, 2011).
- Derivative-free and metaheuristic methods: genetic algorithms (GA), particle swarm optimization (PSO), and other search methods that do not require gradients; often easier to couple to commercial simulators but may require many simulations.

Because full-physics simulation is expensive, many studies accelerate optimization using surrogate or proxy models (e.g., neural networks, gradient boosting) trained on simulator runs. This approach can dramatically reduce the number of full simulations required, particularly for multi-well placement problems (Alfarizi, Stanko, & Bikmukhametov, 2022; Mao & Jahanbani Ghahfarokhi, 2026).

2.3.5 Closed-loop reservoir management

Closed-loop reservoir management (CLRM) integrates model calibration (history matching), optimization, and decision updating in repeated cycles as new data arrive. The goal is not a one-time ‘optimal plan’ but continuously improved decisions under uncertainty. Reviews emphasize the role of automation, uncertainty quantification, and computational efficiency as key enablers for CLRM (Hou et al., 2015).

2.4 Numerical Simulation Tools with Focus on CMG IMEX

2.4.1 Overview of the CMG software suite

Computer Modelling Group Ltd. (CMG) provides an integrated suite of reservoir engineering tools spanning model building, simulation, optimization, and visualization. The main components include Builder (pre-processing and model construction), IMEX (black-oil and unconventional simulation), GEM (compositional simulation), STARS (thermal and advanced processes), CMOST (sensitivity analysis, history matching, and optimization), Results (post-processing), and Win Prop (fluid property characterization) (Computer Modelling Group Ltd., n.d.-a).

This integration supports a workflow where static and dynamic data are assembled in Builder, simulations are executed in the appropriate simulator (IMEX/GEM/STARS), outputs are analyzed in Results, and automated calibration/optimization studies are run through CMOST (Computer Modelling Group Ltd., n.d.-b).

2.4.2 IMEX model (black-oil simulator) and its capabilities

IMEX is CMG's black-oil and unconventional reservoir simulator designed to model primary, secondary, and selected tertiary recovery processes using a black-oil formulation. According to CMG's product description, IMEX supports structurally complex heterogeneous reservoirs and large-scale models, and it is designed for efficient, reliable forecasting (Computer Modelling Group Ltd., n.d.-c).

Key physical and numerical capabilities

- Adaptive-Implicit formulation and massively parallel capability for improved performance on large models.

- Conventional black-oil modeling for oil, gas, and water phases with standard PVT and SCAL input.
- Unconventional modeling features including hydraulic fracture representation and fractured reservoir capabilities.
- Dual-porosity and dual-permeability options (including coupling to discrete fracture network and hydraulic fracturing workflows).
- Well modeling features such as grid-independent wells and detailed segmented wellbore modeling options.
- Workflow integration with CMOST for history matching and optimization studies.
- Support for selected EOR-style approximations within a black-oil framework (e.g., polymer, pseudo-miscible gas flooding) and screening of recovery mechanisms prior to higher-fidelity compositional/thermal simulation (Computer Modelling Group Ltd., 2024; Computer Modelling Group Ltd., n.d.-c).

Strengths of IMEX for graduation-project studies

- Lower data and runtime requirements than compositional/thermal simulators, which is practical for multi-scenario optimization.
- Strong suitability for water flood and pressure-maintenance studies in black-oil reservoirs.
- Industry-standard workflow support (Builder → IMEX → Results) and direct coupling to CMOST for automation.

Limitations and modeling considerations

- Black-oil approximations may be insufficient for strong compositional effects (e.g., rich gas cycling, condensate banking).
- EOR processes that require detailed component tracking or thermal effects may require GEM or STARS for high fidelity.

- Optimization results depend strongly on model calibration and on the realism of constraints and uncertainty representation.

2.5 Previous Studies on Multi-Well Optimization Using IMEX or Similar Simulators

2.5.1 Optimization with IMEX-CMOST workflows (CMG case evidence)

CMG publications illustrate the use of IMEX coupled with CMOST for multi-parameter optimization. In a case study on the La Cira Infantas oilfield waterflood pattern, CMOST was used with IMEX to optimize both completion parameters (valve configuration and opening fractions) and operating controls (injection rate and bottom-hole injection pressure) for an inverted 5-spot pattern over a 15-year period. The study framed a multi-objective problem to maximize cumulative oil while minimizing cumulative water production and reported improvements on the Pareto front after hundreds of simulation runs (Computer Modelling Group Ltd., 2021).

2.5.2 IMEX-supported well placement optimization using evolutionary methods

Irawan, Wayo, Satyanaga, and Kim (2024) presented a global genetic algorithm workflow for automating well deployment in a synthetic reservoir model built in CMG Builder and simulated using IMEX. The authors used CMOST as the optimization engine to vary well indices (i, j, k) for multiple wells and to evaluate cumulative oil production across generations. This study demonstrates the feasibility of integrating IMEX with evolutionary optimization for multi-well placement.

2.5.3 multi-well optimization with surrogate models and numerical simulators

Because multi-well optimization can require thousands of simulator evaluations, recent studies emphasize acceleration using proxy models. Alfarizi et al. (2022) coupled a genetic algorithm with an artificial neural network surrogate for a waterflooding control optimization problem, reducing computational cost while preserving solution quality. Similarly, Mao and Jahanbani Ghahfarokhi (2026) proposed machine learning proxy models integrated with genetic algorithms to accelerate multi-well placement optimization for CO₂-enhanced oil recovery and storage.

2.5.4 Benchmark models and broader optimization literature

Benchmark datasets help compare optimization algorithms and evaluate multi-well interaction effects. The ‘Egg model’ is a widely used geological ensemble designed for reservoir simulation and control/optimization research (Jansen et al., 2014). Broader reviews of well control optimization discuss adjoint-based methods, handling of constraints, and the integration of optimization with data assimilation in closed-loop workflows (Jansen, 2011; Hou et al., 2015).

2.6 Key Parameters Affecting Production (Permeability, Porosity, Pressure, etc.)

Production in a multi-well reservoir is governed by interacting geological, fluid, and operational parameters. In simulation and optimization, these parameters define both the baseline behavior and the sensitivity of objectives to changes in controls. Key groups are summarized below (Dake, 1978; Aziz & Settari, 1979).

2.6.1 Rock and structural parameters

- Porosity (ϕ): controls hydrocarbon pore volume and strongly affects reserves and recovery.
- Permeability (k) and anisotropy (k_h/k_v): controls mobility and vertical communication; heterogeneity drives early breakthrough.
- Net-to-gross, thickness, and layering: determine flow capacity and vertical sweep behavior.

- Fault and barrier transmissibility: can compartmentalize flow and change well interference patterns.
- Fracture properties (for fractured reservoirs): fracture permeability, spacing, conductivity, and connectivity.

2.6.2 Fluid and rock-fluid interaction parameters

- PVT properties: oil/gas formation volume factors, viscosities, solution gas-oil ratio, compressibility.
- Relative permeability endpoints and curves: control phase mobilities and water cut behavior.
- Capillary pressure and wettability effects: influence saturation distribution and residual oil.
- Formation damage or stimulation: represented via skin and near-well multipliers.

2.6.3 Pressure, saturation, and boundary conditions

- Initial reservoir pressure and depletion level: affect deliverability and drive mechanism dominance.
- Bubble-point pressure: governs gas liberation and nonlinear IPR behavior in solution-gas drive (Vogel, 1968).
- Aquifer strength and boundary type (closed, edge-water, bottom-water): influence pressure support and water encroachment.
- Initial contacts (OWC/GOC) and saturation distribution: control early water/gas production risk.

2.6.4 Well and operational parameters

- Well locations, spacing, and pattern geometry: determine interwell connectivity and sweep efficiency.
- Well constraints (rate/BHP limits) and control schedule: directly define optimization decision variables.

- Injection allocation and voidage replacement: influence pressure maintenance and displacement efficiency.
- Completion strategy (perforation interval, ICD/ICV settings): redistributes inflow and can delay breakthrough in layered systems (Computer Modelling Group Ltd., 2021).
- Well modeling (well index, radius, skin): numerical mapping of near-well flow, commonly using Peaceman-type well models (Peaceman, 1978).

2.6.5 Uncertainty and sensitivity

Uncertainty in geological properties, fault behavior, and relative permeability can dominate forecast uncertainty. Sensitivity analysis identifies which uncertain parameters most influence objectives and can guide where to invest in data acquisition (e.g., pressure surveys, well tests, updated geological interpretation). CMOST and similar tools support structured sensitivity and uncertainty workflows that are compatible with IMEX-based models (Computer Modelling Group Ltd., n.d.-b).

2.7 Summary of Literature and Identified Research Gap

2.7.1 Literature synthesis

The reviewed literature shows that reservoir simulation is central to forecasting and decision support, especially when heterogeneity and multi-well interactions dominate reservoir behavior (Aziz & Settari, 1979; Gerritsen & Durlofsky, 2005). Reservoir productivity depends on fundamental flow physics, near-well representation, and multiphase effects, captured through well models and IPR concepts (Peaceman, 1978; Vogel, 1968). Production optimization extends these ideas by framing field management as a constrained optimization problem, with both gradient-based (adjoint) and derivative-free methods used in practice (Jansen, 2011; Hou et al., 2015).

With respect to CMG workflows, IMEX offers a practical black-oil simulation platform that can be integrated with CMOST for automation, history matching, and optimization. Published CMG case evidence and recent academic work demonstrate that IMEX can be coupled to evolutionary algorithms through CMOST to optimize multi-parameter problems involving several wells and controls (Computer Modelling Group Ltd., 2021; Irawan et al., 2024).

2.7.2 Identified research gap

Despite progress, several practical gaps remain for student and field-oriented studies focused on IMEX-based optimization:

- Limited openly documented, step-by-step academic workflows that use IMEX specifically for multi-well production optimization under realistic operational constraints (facility limits, injection capacity, BHP bounds) and for long-term forecasting.
- Many optimization studies focus either on well placement or on well control; fewer integrate both within one consistent IMEX-based workflow.
- Computational cost remains a barrier in multi-well optimization; there is a need to demonstrate efficient study design (screening, sensitivity, and staged optimization) that reduces simulations while maintaining engineering realism.
- Uncertainty handling is often simplified; practical guidance is needed on how sensitivity/uncertainty analysis can be coupled with optimization to produce robust well-control recommendations.

Accordingly, this graduation project addresses these gaps by developing and documenting an applied workflow for production optimization in a multi-well black-oil reservoir using CMG IMEX (with optimization concepts compatible with CMOST), emphasizing clear objective definition, realistic constraints, sensitivity-informed parameter selection, and transparent reporting of optimization outcomes.

Chapter Three

Theoretical Background

3.1 Overview

This chapter outlines the approach used to assess and improve production performance in a multi-well oil reservoir through numerical simulation. The research was carried out utilizing the black-oil simulator CMG IMEX. The approach consists of building models, preparing data, configuring wells, establishing operational limits, creating simulation scenarios, and setting performance evaluation standards.

3.2 Reservoir Model Description

A three-dimensional black-oil simulation model was developed to represent a conventional oil reservoir. The reservoir was divided into a structured grid system to capture the spatial distribution of rock and fluid properties.

The model included:

- Porosity distribution
- Permeability in horizontal and vertical directions
- Layer thickness
- Initial reservoir pressure (6000 psi)
- Bubble point pressure (3600 psi)
- Initial oil, gas, and water saturations

The reservoir was assumed to be a closed system without active aquifer support in order to clearly evaluate the impact of water injection on pressure behavior.

Table 3.1: Reservoir Layer Properties Used in the Simulation Model

Layer sequence	Top depth (ft)	Permeability x direction (md)	Porosity	Thickness (ft)
1	9000	66	0.087	20
2		473	0.097	15
3		238	0.111	26
4		25	0.16	15
5		20	0.13	16
6		163	0.17	14
7		71	0.17	8
8		61	0.08	8
9		180	0.14	18
10		113	0.13	12
11		63	0.12	19
12		28	0.105	18
13		20	0.12	20
14		24	0.116	50
15		71	0.157	100

3.3 Fluid and Rock Properties

The black-oil model was used to describe the fluid system. PVT properties included:

- Oil formation volume factor
- Gas formation volume factor
- Oil viscosity
- Gas viscosity
- Solution gas-oil ratio

Rock compressibility was also included to account for pressure-dependent pore volume changes.

3.3.1 PVT Data

- ❖ Oil density 44.986 lb./ft³
- ❖ Gas specific gravity 0.92
- ❖ Water density 63.021 lb./ft³
- ❖ Oil compressibility 1E-6 1/psi
- ❖ Water formation volume factor 1.0034
- ❖ Water compressibility 1E-6 1/psi
- ❖ Reference water pressure 6000 psi
- ❖ Water viscosity 0.96
- ❖ Water compressibility dependence to pressure 0
- ❖ Bubble point pressure 3600 psi

Table 3.2 Fluid and Rock Properties for the Black-Oil Model

P	Rs	Bo	Zg	μo	μg
14.7	0	1	0.999 9	1.2	0.012 5
400	165	1.012	0.836 9	1.17	0.013
800	335	1.025 5	0.837	1.14	0.013 5
1200	500	1.038	0.834 1	1.11	0.014
1600	665	1.051	0.834 1	1.08	0.014 5
2000	828	1.063	0.837	1.06	0.015

2400	985	1.075	0.834 1	1.03	0.015 5
2800	1130	1.087	0.834 1	1	0.016
3200	1270	1.098 5	0.839 8	0.98	0.016 5
3600	1390	1.11	0.829 9	0.95	0.017
4000	1500	1.12	0.83	0.94	0.017 5
9000	1510	1.121	0.830 1	0.93	0.017 6

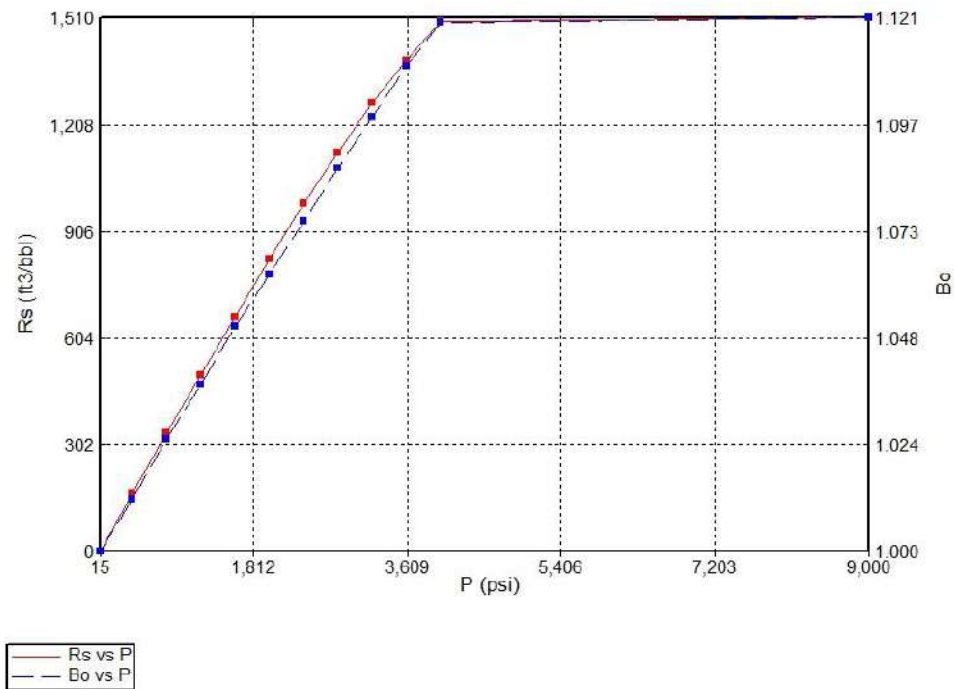


Figure 3.1: Variation of solution gas-oil ratio (R_s) and oil formation volume factor (B_o) with pressure for the reservoir fluid model.

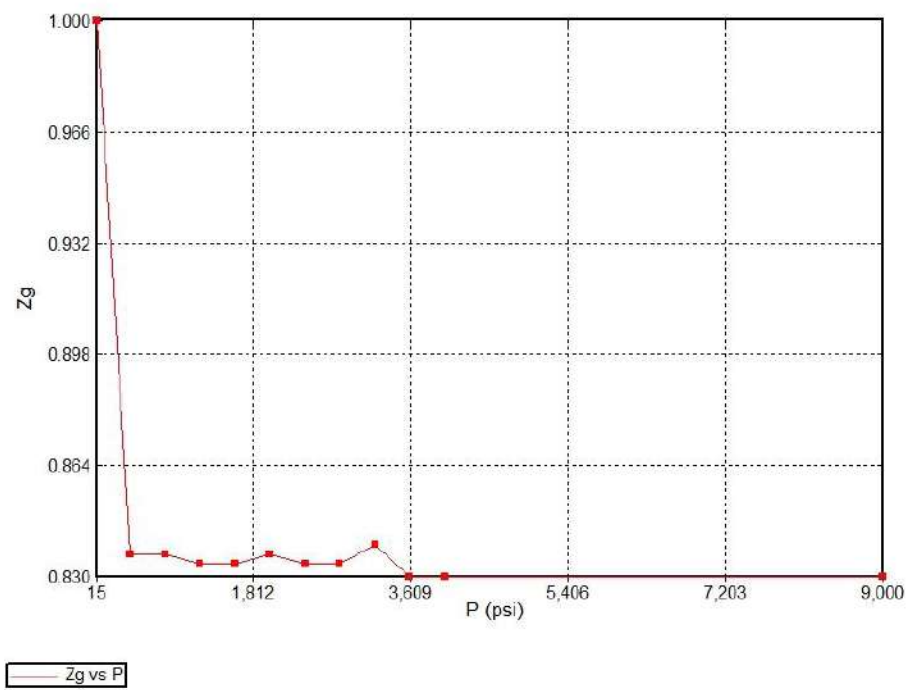


Figure 3.2: Gas compressibility factor (Z_g) as a function of pressure for the reservoir gas.

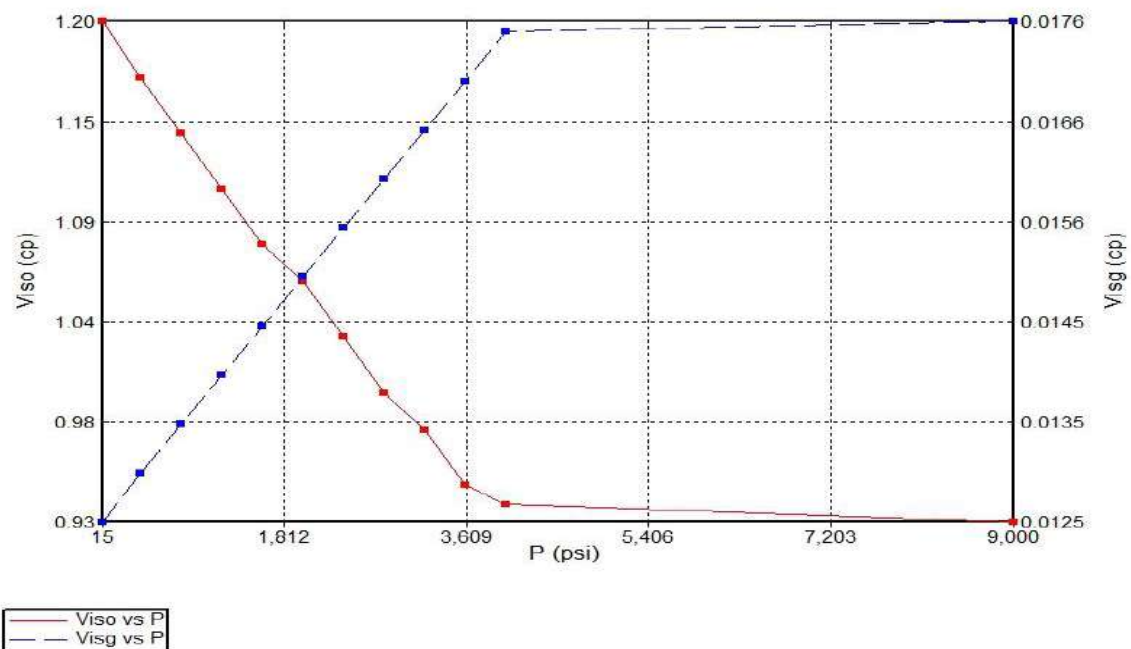


Figure 3.3: Variation of oil viscosity and gas viscosity with pressure used in the black-oil fluid model.

3.3.2 Relative Permeability Modeling

Three-Phase Relative Permeability Modeling

To effectively replicate the behavior of multiphase flow within the reservoir, the three-phase relative permeability was represented using the Stone II method applied in CMG IMEX.

Figure (3.4) shows how the oil relative permeability (K_{ro}) varies based on the levels of water and gas saturation. The ternary diagram illustrates how oil, water, and gas phases interact and shows that as the levels of water and gas increase, the movement of oil becomes more limited.

The Stone II model enables the interpolation of two-phase relative permeability curves to predict three-phase flow behavior. This capability is crucial for accurately forecasting reservoir performance, particularly in scenarios involving water injection.

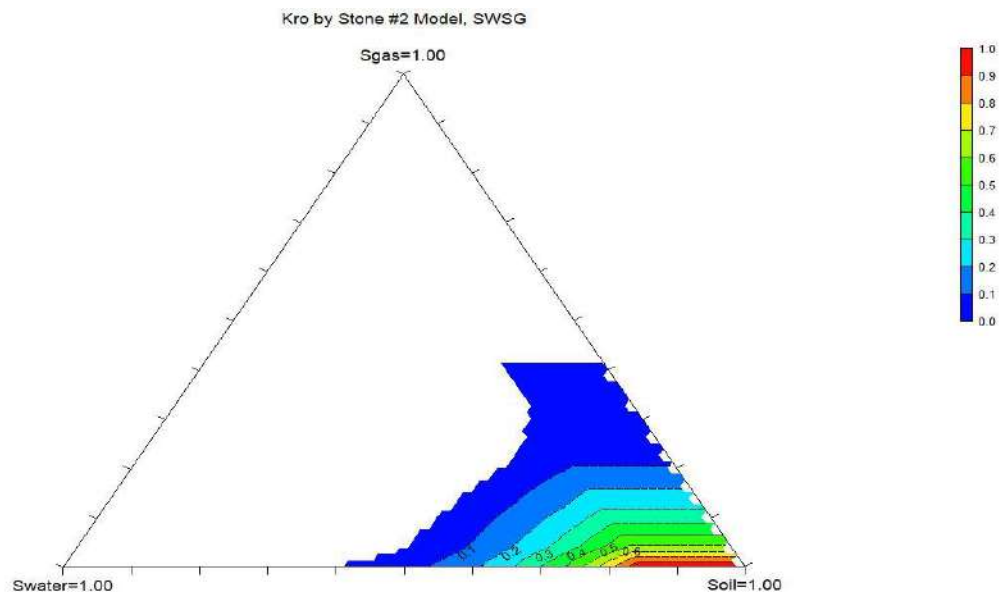


Figure 3.4: Oil relative permeability distribution calculated using the Stone II three-phase model.

3.4 Well Configuration and Pattern Design

The reservoir model included several production wells and one main water injection well organized in an inverted five-spot formation.

The production wells were managed under the same circumstances to ensure uniformity in evaluating their performance.

Perforations were carried out in Layers 9, 10, and 11 because of their advantageous properties of porosity and permeability.

Figure 3.5 depicts the layout of production and injection wells utilized in the simulation model.

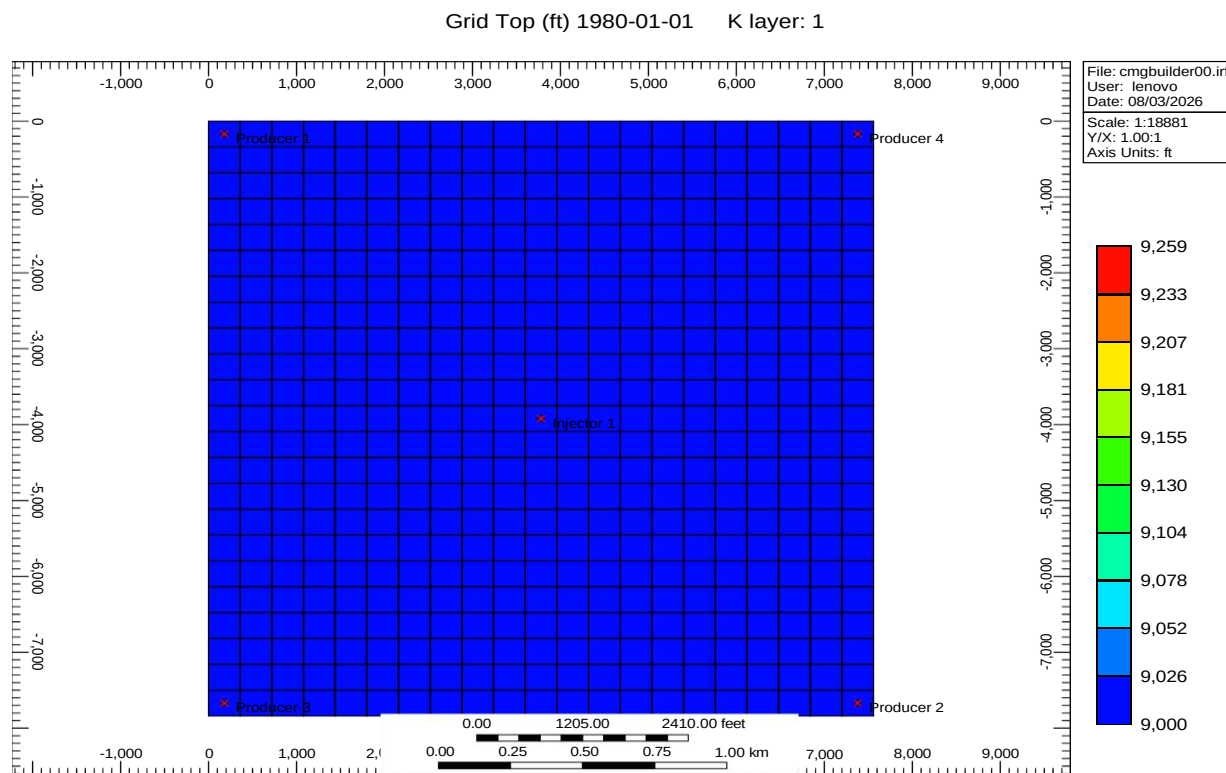


Figure 3.5 Well configuration showing the inverted five-spot pattern used in the reservoir simulation model.

3.5 Operational Constraints

To guarantee realistic simulation performance, operational limitations were established.

Production Wells:

- The lowest allowable pressure at the bottom-hole pressure (BHP) should be 1500 psi.
- Restrictions on oil pricing
- Monitoring of water cut
- Limits on the gas-to-oil ratio

Injection Well:

- Steady injection rate: 6000 barrels of water per day.
- Management of injection pressure at the bottom-hole pressure (BHP)

These limitations enabled the assessment of production sustainability in situations that require ongoing maintenance.

3.6 Simulation Situations

Two primary situations are created through simulation:

Scenario 1 - Natural Depletion

The reservoir was created without any assistance from outside pressure. This situation served as a foundational example to assess the decrease and recovery of pressure due to natural energy influences.

Scenario 2 - Water Injection

Water injection began in 1984, prior to the reservoir pressure attaining the bubble-point pressure. The injection rate was set at 6000 barrels of water per day. This situation assessed the effectiveness of pressure support and its impact on total oil production and recovery ratio.

3.7 Method of Prediction

A forward simulation prediction was conducted up to the year 2030 under ongoing injection conditions. The aim was to examine long-term trends in production and the patterns of pressure.

3.8 Performance Evaluation Criteria

Reservoir performance was evaluated using the following key performance indicators (KPIs):

- Average reservoir pressure (POVO)
- Cumulative oil production
- Recovery factor
- Water-oil ratio (WOR)
- Bottom-hole pressures
- These parameters were used to compare depletion and injection cases.

3.9 Modeling Assumptions and Limitations

Building this model required a few simplifying assumptions. Fracture pressure limits were not included, nor were any economic constraints or full history matching against real field data. Rock properties were also assumed to be uniform laterally across each layer. Because of these simplifications, the results should be read as a technical assessment of reservoir behavior rather than a precise prediction of what would happen in an actual field.

3.10 An Overview of the CMG Simulation Suite: The Computer Modeling (CMG)

Suite is a popular reservoir modeling software used in both academic and industrial applications. It provides sophisticated digital tools for simulating fluid dynamics and reservoir performance under various operating conditions. The CMG suite comprises several simulation programs, each designed to suit specific reservoir types and study objectives. The core simulation programs in the CMG suite include IMEX, GEM, and CMOST. IMEX is used for simulating black oil reservoirs and is designed for modeling conventional oil and gas reservoirs containing oil, gas, and water. It is suitable for studies focusing on pressure behavior, reservoir productivity, and water injection processes. The GEM is a composition simulator, primarily used in complex extraction processes such as gas injection, miscible flooding, and carbon dioxide injection, where the effects of fluid composition must be carefully considered. The CMOST is a calibration and optimization tool often used for automated calibration and analysis.



Figure 3.6: Main modules of the CMG simulation suite (2015.10), including GEM, IMEX, STARS, WINPROP, and CMOST, used for reservoir simulation, fluid modeling, and optimization studies.

The study aimed to address the inherent uncertainty and evaluate reservoir behavior based on simulation data. CMG IMEX was selected because the reservoir under investigation is a conventional oil reservoir, and the objective was to evaluate reservoir behavior and compare depletion and water injection scenarios. Structural modeling and automated optimization were not necessary due to the lack of production data. Therefore, IMEX provided a suitable and efficient platform for achieving the objectives of this research.

3.11 Data Collection and Input Parameters:

This study constructed a numerical simulation model using a pre-approved data file containing pertinent reservoir, fluid, and well characteristic information. Along with qualities of fluids (water, oil, and gas), initial pressure, and bubble point pressure, the data included characteristics of reservoir rocks including porosity, permeability, and layer thickness.

Well data defining their sites, types (such as injection wells and production wells), and operational limitations were also included. The (CMG) software was given all of this data to analyze the reservoir's performance under several operating conditions.

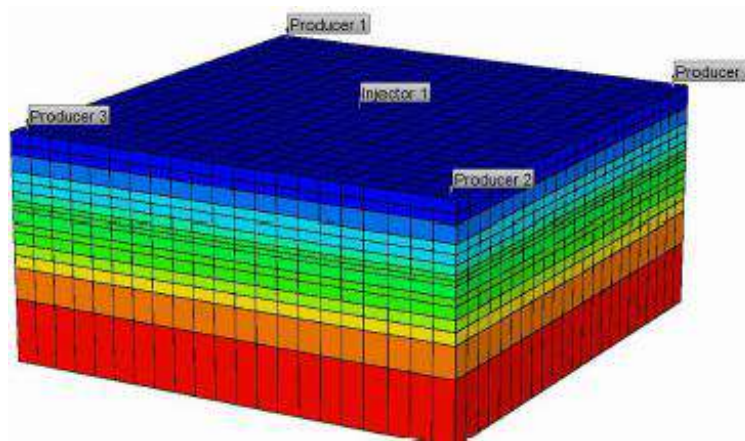


Figure 3.7: Three-dimensional reservoir simulation model showing grid structure, layered reservoir properties, and well locations including one injection well and four production wells

3.12 Model Creation in CMG IMEX

The numerical model was created using CMG IMEX software, which employs the Black Oil Model to replicate the movement of oil, gas, and water in the reservoir. The reservoir was divided into a three-dimensional grid to illustrate how rock and fluid properties are distributed in space.

The initial condition of the reservoir was established with a pressure that exceeded the bubble point pressure, signifying that the reservoir was in an unsaturated oil state at the commencement of production. The reservoir was considered a closed system without any outside water supply to enhance the understanding of the impacts of production and water injection.

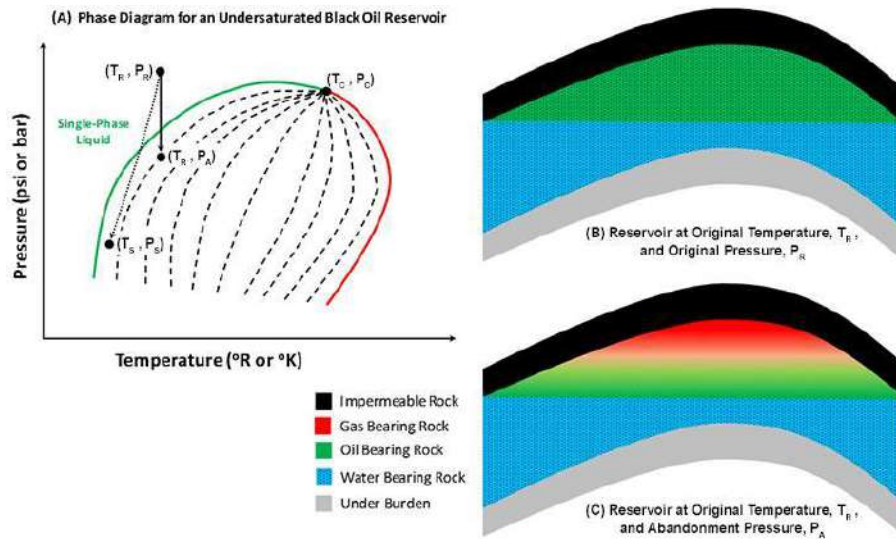


Figure 3.8: Under Saturated Oil Reservoir (black oil)

3.13 Wells Setup and Operating Limitations

Several production wells were identified within the reservoir, along with a single water injection well positioned in the center of the field, following an inverted five-spot arrangement. All production wells were operated under identical conditions to maintain uniformity in evaluating their performance.

Operational limitations were imposed on the production wells, which included a minimum bottom-hole pressure requirement to avoid overly significant pressure

reduction. Extra limits were placed on the oil production rate, water cut, and gas-oil ratio to guarantee consistent well performance.

For the injection well, parameters were established for the water injection rate and bottom-hole pressure to ensure that the injection process remains controlled and stable.

3.13.1 perforation time windows

Based on the available geological and petrophysical data, chosen reservoir layers completed the production and injection wells. For both the injection wells and the production wells, layers 9, 10, and 11 set the first perforation ranges. These layers were picked for their better reservoir qualities including porosity and permeability in contrast with other strata.

Using the same perforating distances for both the producers and the injector helped the wells interact well and allowed a constant evaluation of pressure assistance and fluid motion throughout the simulation. To emphasize the impacts of production and water injection on the reservoir's performance, the perforation intervals stayed constant all through the simulation duration.

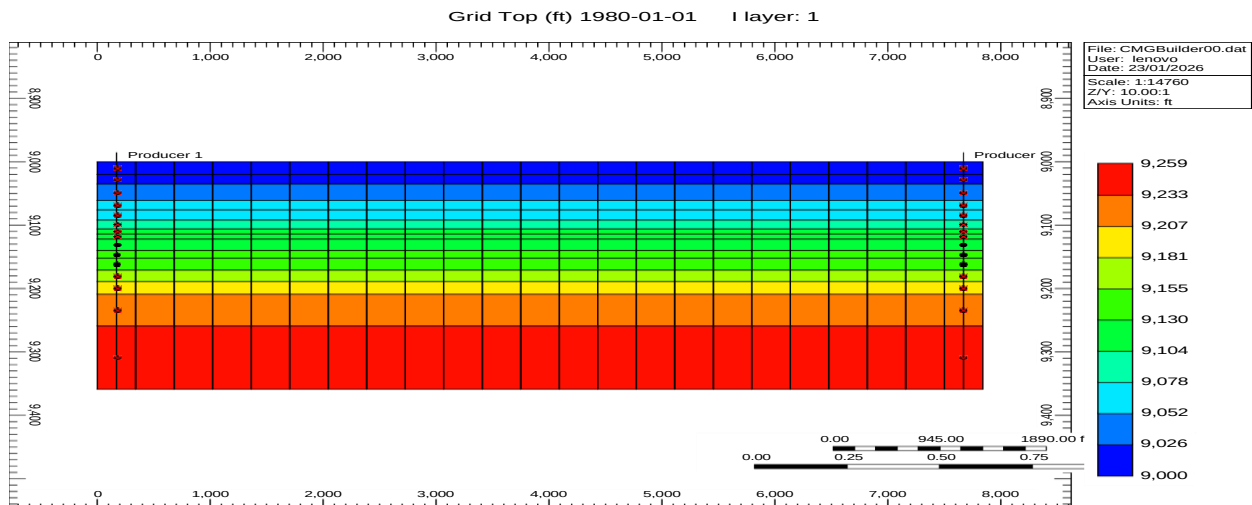


Figure 3.9: Vertical section of the reservoir model showing the perforation intervals selected for the production and injection wells in layers 9, 10, and 11.

3.14 Simulation situations:

Two main simulation scenarios were investigated in this research:

1. Depletion (Before Injection) Scenario In this instance, the reservoir was extracted without any outside pressure aid to evaluate its natural depletion pattern, the reduction in reservoir pressure, and the general production performance. Scenario Involving Water Injection.
2. Water injection started in this case after a period of output and before the reservoir pressure approached the bubble-point pressure. The aim was to evaluate how well holding pressure impacted oil recovery.

Each scenario was modelled across a lengthy period to investigate the reservoir's behavior throughout time.

3.15 Performance Evaluation Criteria

Reservoir performance was evaluated using several key indicators, including:

- Average reservoir pressure (Pore Volume Weighted Pressure - POVO).
- Cumulative oil production.
- Recovery factor.
- Water-oil ratio (WOR).
- Gas-oil ratio (GOR)

These indicators were used to compare the depletion case with the water injection case. Detailed analysis and discussion of the results are presented in the following chapter.

3.16 Modeling Assumptions and Limitations

To simplify the simulation model, several assumptions were made. It was thought that rock features are constant across laterally, therefore factors connected to geomechanics including restrictions based on fracture pressure were ignored. Moreover, this research omitted economic analysis and historical data vs real field data comparison.

Therefore, rather than an accurate representation of real field activities, the results obtained act as a conceptual evaluation of reservoir behavior and the impacts of water injection.

The results obtained from the simulation model are presented and discussed in the following chapter.

Chapter Four

Mathematical modelling

4.1 Overview

Oil recovery operations traditionally have been subdivided into three stages: primary, secondary, and tertiary.

The terms primary oil recovery, secondary oil recovery, and tertiary (enhanced) oil recovery are traditionally used to describe hydrocarbons recovered according to the method of production or the time at which they are obtained.

Primary recovery, the initial production stage, resulted from the displacement energy naturally existing in a reservoir.

Secondary recovery, the second stage of operations, usually was implemented after primary production declined.

Traditional secondary recovery processes are waterflooding and gas injection, although the term secondary recovery is now almost synonymous with waterflooding.

Tertiary recovery (enhanced oil recovery EOR), the third stage of production, was that obtained after waterflooding. As shown in the Figure 4.1: Oil Recovery Methods: Primary, Secondary, and Tertiary Recovery

4.2 Primary Oil Recovery

Describes the production of hydrocarbons under the natural driving mechanisms present in the reservoir without supplementary help from injected fluids such as gas or water.

The natural energy of the reservoir used to transport hydrocarbons towards and out of the production wells is called Drive Mechanisms.

- ❖ There are five important drive mechanisms;
 - Solution Gas Drive.
 - Gas Cap Drive.
 - Water Drive.
 - Gravity Drainage.
 - Combination Drive

Table 4.1: Reservoir Drive Mechanisms and Recovery Factors

Depletion drive (solution gas drive)	Gas Cap drive	Water Drive	Gravity Drainage
Expansion of gas evolved from solution	Expansion of Gas (cap gas)	Production of oil by water displacing process & usually most efficient process	As a result of difference in reservoir fluid densities
Low oil recovery (5-15%)	Moderate oil recovery (20-40%)	High recovery (25-50%)	High recovery. (<80%)

In most cases, the natural driving mechanism is a relatively inefficient process and results in a low overall oil recovery.

The lack of sufficient natural drive in most reservoirs has led to the practice of supplementing the natural reservoir energy by introducing some form of artificial drive, the most basic method being the injection of gas or water.

4.3 Secondary Oil Recovery

Refers to the additional recovery that results from the conventional methods of water- injection and immiscible gas injection.

Usually, the selected secondary recovery process follows the primary recovery, but it can also be conducted with the primary recovery.

Water flooding is the most common method of secondary recovery. However, before undertaking a secondary recovery project, it should be clearly proven that the natural recovery processes are insufficient, otherwise there is a risk that the substantial capital investment required for a secondary recovery project may be wasted.

Secondary recovery methods are not sufficient to recover the hydrocarbons remaining in the reservoir and this is due the following factors:

- 1) High viscosity of oil.
- 2) Trapping of oil in some areas of the reservoir due to capillary forces and variation of permeability.

Secondary recovery results from the increasing of natural energy through injection of water or gas to displace oil toward producing wells.

Gas injection, in this case, is either into a gas cap for pressure maintenance and gas-cap expansion or into oil-zone to displace oil immiscibly according to relative permeability and volumetric sweepout considerations.

Gas processes based on other mechanisms, such as oil swelling or oil viscosity reduction are considered EOR processes.

An immiscible gas displacement is not as efficient as a waterflood and is used infrequently as a secondary recovery process today.

Today, waterflooding is almost synonymous with the secondary recovery classification.

4.4 Tertiary (Enhanced) Oil Recovery

Is that additional recovery over and above what could be recovered by primary and secondary recovery methods.

Various methods of enhanced oil recovery (EOR) are essentially designed to recover oil,

Commonly described as residual oil, left in the reservoir after both primary and secondary recovery methods, in general EOR methods fall into three main groups, all are very expensive, they are only used when economical;

A. Thermal EOR

These processes use heat to improve oil recovery by reducing the viscosity of heavy oils and vaporizing lighter oils and, hence improving their mobility. Thermal EOR is probably the most efficient EOR approach.

B. Chemical EOR

- These processes use chemicals added to water in the injected fluid of a water flood to alter the flood efficiency in such a way as to improve oil recovery.
 - This can be done in many ways, for example: Increasing water viscosity by adding polymer to injected water (polymer floods).
 - Chemicals may mix with oil to change mobility ratio.
- Decrease oil viscosity
- Increase displacing fluid viscosity

C. Miscible Gas Flooding

- This method uses a fluid that is miscible with the oil. Such a fluid dissolved in the oil and can flush out all of the oil remaining in place.
- In practice CO₂ and N₂ gas are used since these gases have high mobilities and can easily enter all the pores in the rock, also these gases are miscible in the oil.
- Generally, EOR methods more expensive than conventional methods (water and immiscible gas injection).

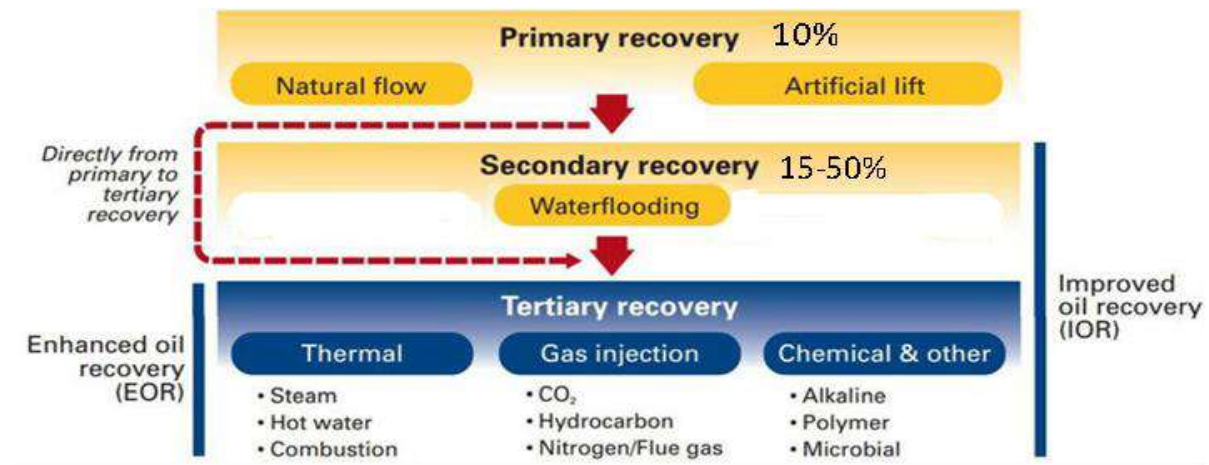


Figure 4.1: Oil Recovery Methods: Primary, Secondary, and Tertiary Recovery

4.5 Microscopic and Macroscopic Displacement

The overall displacement efficiency of any oil recovery displacement process can be considered as the product of microscopic and macroscopic displacement efficiencies. In equation form;

$$E = E_D \times E_V \dots \dots \dots (4.1)$$

Where;

E=overall displacement efficiency (oil recovered by process/ oil in place at start of process),

E_D =microscopic displacement efficiency expressed as a fraction, and

E_V=macroscopic (volumetric) displacement efficiency expressed as a fraction.

4.5.1 Microscopic displacement

Relates to the displacement of oil at the **pore scale**. That is, E_D is a measure of the effectiveness of the displacing fluid in moving (mobilizing) the oil at those places in the rock where the displacing fluid contacts the oil. E_D is reflected in the magnitude of the residual oil saturation (S_{or}) in the areas contacted by the displacing fluid.

$$E_D = \frac{\text{Oil displaced from contacted pores}}{\text{Oil originally present in contacted pores}} \dots \dots \dots (4.2)$$

- **Indicator: The residual oil saturation (S_{or}) after displacement.**
 - Lower S_{or} → higher microscopic efficiency.
 - Higher S_{or} → poorer microscopic efficiency.

4.5.2 Macroscopic displacement

Refers to how effectively the displacing fluid sweeps through the whole reservoir volume.

Alternative terms represent the same general concept are volumetric sweep efficiency E_V.

E_V is a measure of how effectively the displacing fluid sweeps out the volume of a reservoir, both areally and vertically, as well as how effectively the displacing fluid moves the displaced oil toward production wells.

Both areal and vertical sweeps must be considered, and it is often useful to further subdivide E_v into the product of areal and vertical displacement efficiencies.

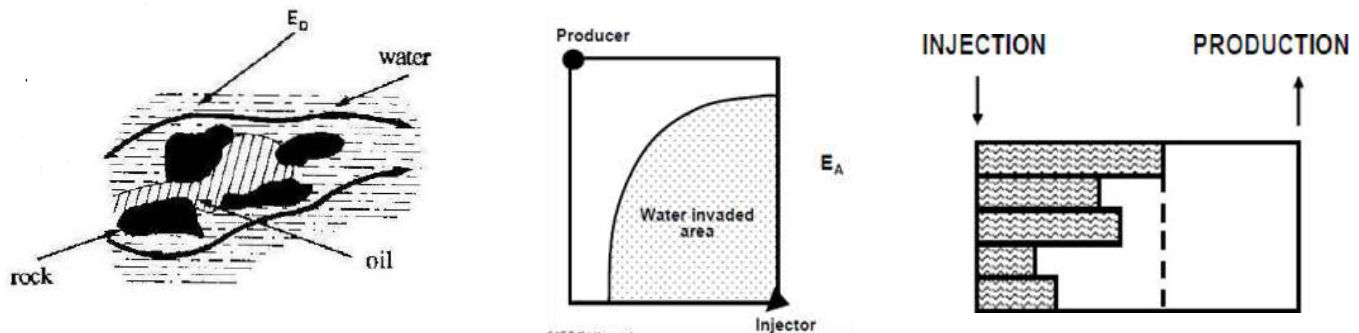


Figure 4.2: Sweep Efficiency in Oil Recovery: Displacement, Areal, and Vertical Sweep Efficiency

Note that the product of areal and vertical sweeps is called the volumetric sweep efficiency and represents the overall fraction of the flood pattern that is contacted by the injected fluid.

E_v is reflected in the magnitude of average or overall residual oil saturation (S_{or}) because this average is based on residual oil in both swept and unswept parts of the reservoir.

- Swept zones – areas contacted by the displacing fluid.
- Unswept zones – areas not contacted by the displacing fluid.

Therefore:

- If sweep is efficient $\rightarrow$ overall residual oil saturation (S_{or}) is lower $\rightarrow$ E_v is higher.
- If sweep is poor (large unswept zones) $\rightarrow$ overall S_{or} is higher $\rightarrow$ E_v is lower.

Note:

Microscopic Scale: Pore-level.

Macroscopic Scale: Reservoir scale.

4.6 Mobility Ratio

The mobility ratio (M) is a key parameter controlling displacement efficiency and is defined as:

$$M = (\text{mobility of displacing fluid}) / (\text{mobility of displaced fluid})$$

- If $M < 1 \rightarrow$ stable displacement and high sweep efficiency
- If $M > 1 \rightarrow$ unstable displacement (viscous fingering) and poor recovery

A favorable mobility ratio improves both microscopic and macroscopic efficiencies.

4.7 Recovery by Water Displacement "Water Flooding"

Water flooding is the most widely used fluid injection process in the world today. It has been recognized since 1880 that injecting water into an oil-bearing formation has the potential to improve oil recovery, but it did not experience field wide application until the 1930s when several injection projects were initiated. Many complex enhanced recovery processes have been developed through the years to recover the oil reserves left behind by inefficient primary recovery mechanisms, although many of these processes have the potential to recover more oil than water flooding in a particular reservoir, but no process has been discovered which enjoys the widespread applicability of water flooding. As shown in the Figure 4.3: Water Injection Well for Oil Recovery

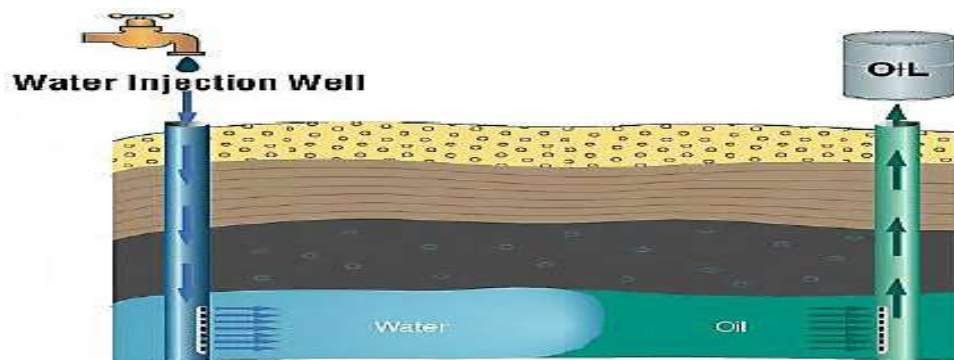


Figure 4.3: Water Injection Well for Oil Recovery

- The primary reasons why water flooding is the most successful and most widely used oil recovery process are:
 - general availability of water.
 - low-cost relative to other injection fluids.

- ease of injecting water into a formation.
- high efficiency with which water displaces oil.

Water flood is the injection of water into reservoir to increase reservoir energy and sweeps, or “drive” oil to another produced well where it can be produced. Water flooding is widely applied secondary recovery method. Today, these injections are sometimes used from the start of the life of the reservoir. Before undertaking one of these processes, it is still necessary to make sure of the insufficiency of natural mechanisms, and this is difficult to determine at the start of field production. It is also generally necessary to have a minimum of production data (one to two years of production).

4.7.1 Goal of Water flooding

Increase the amount of oil recovered from the reservoir by:

- Maintaining reservoir pressure.
- Displacing (sweeping) oil with water

Water injected into the reservoir or into the aquifer downdip of the reservoir increases reservoir energy by replacing fluids withdrawn in primary recovery and re-pressurizing the system.

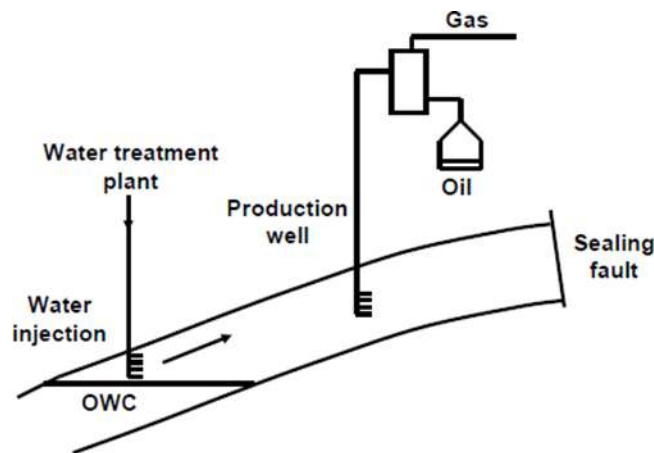


Figure 4.4: Water Injection and Oil Production in a Faulted Reservoir

If a reservoir is produced too long during the primary phase the chances of a successful secondary recovery phase may be reduced. For example, if solution gas drive continues until high gas saturation exists in the pores the final recovery by water injection may be low.

4.8 Reservoir Behavior During Production

The behavior of an oil reservoir during production can be described by the relationship between pressure, gas-oil ratio (GOR), and gas saturation as a function of cumulative oil production.

At the initial stage, the reservoir pressure is high and no free gas exists in the system. The produced gas is entirely dissolved in the oil, and therefore the gas-oil ratio (GOR) remains constant at the solution gas ratio (R_{si}).

As production continues and the pressure declines to the bubble point pressure (P_b), gas begins to come out of solution. At this stage, free gas starts to form in the reservoir, causing an increase in GOR.

Beyond the bubble point, during the gas liberation stage, reservoir pressure continues to decline and gas saturation increases significantly. As a result, GOR rises and typically reaches a peak due to increased production of free gas.

At the late depletion stage, the reservoir becomes highly depleted, and GOR starts to decrease. This decline indicates that the reservoir has lost most of its natural energy, and oil becomes increasingly trapped within the pore spaces.

This stage is critical because it marks the point at which the reservoir may become too depleted for effective water flooding. Therefore, water injection should be initiated before reaching this stage, ideally near the bubble point pressure, to ensure efficient oil displacement and improved recovery.

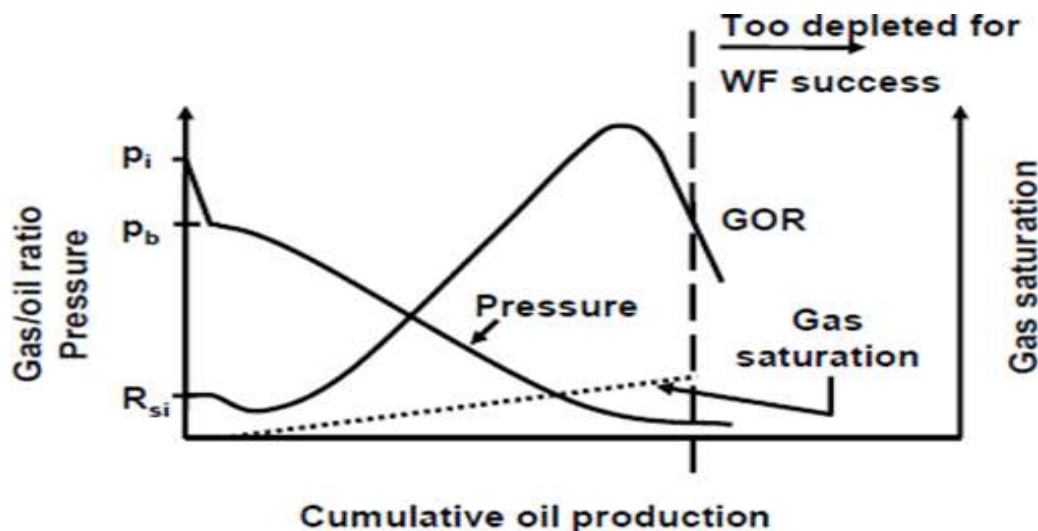


Figure 4.5: Reservoir Performance During Production

4.9 Timing of Water Flooding and Its Impact on Recovery

The timing of water flooding plays a critical role in determining the success of the recovery process. Initiating water injection at an inappropriate stage of reservoir depletion can significantly reduce its effectiveness.

At the late depletion stage, when the gas-oil ratio (GOR) begins to decline, the reservoir pressure is typically very low and most of the natural energy has already been depleted. Under these conditions, a large portion of the oil remains trapped within the pore spaces due to capillary forces and poor mobility. Consequently, the injected water tends to bypass the oil and reach the production wells prematurely, resulting in poor displacement efficiency and low recovery.

Therefore, the optimal time to initiate water flooding is before the GOR starts to decline. This corresponds to the stage shortly after the reservoir pressure drops below the bubble point pressure, while sufficient reservoir energy is still available to support effective displacement.

Starting water injection at this stage ensures better distribution of the injected fluid, improved sweep efficiency, and more effective oil displacement. In contrast, delaying injection until the reservoir becomes highly depleted leads to inefficient flooding and reduced recovery performance.

This highlights the importance of proper reservoir management and early planning of secondary recovery operations to maximize oil recovery.

Chapter Five

Results and Discussion

5.1 Results

5.1.1 Reservoir Pressure Behavior Before Injection

The reservoir pressure response under depletion and water injection circumstances is covered here. The general reservoir pressure behavior was shown using the average reservoir pressure (POVO).

The reservoir pressure dropped consistently from its starting level of about 6,000 psi throughout the depletion phase because oil was being extracted without any pressure help. The pressure came close to the bubble point pressure of around 3,600 psi as production went on, which caused oil flow to slow down and production rates to drop. the wells were shut in after reaching bottom hole pressure, the minimum bottom-hole flowing pressure constraint (BHD = 1500 psi) in 1993.

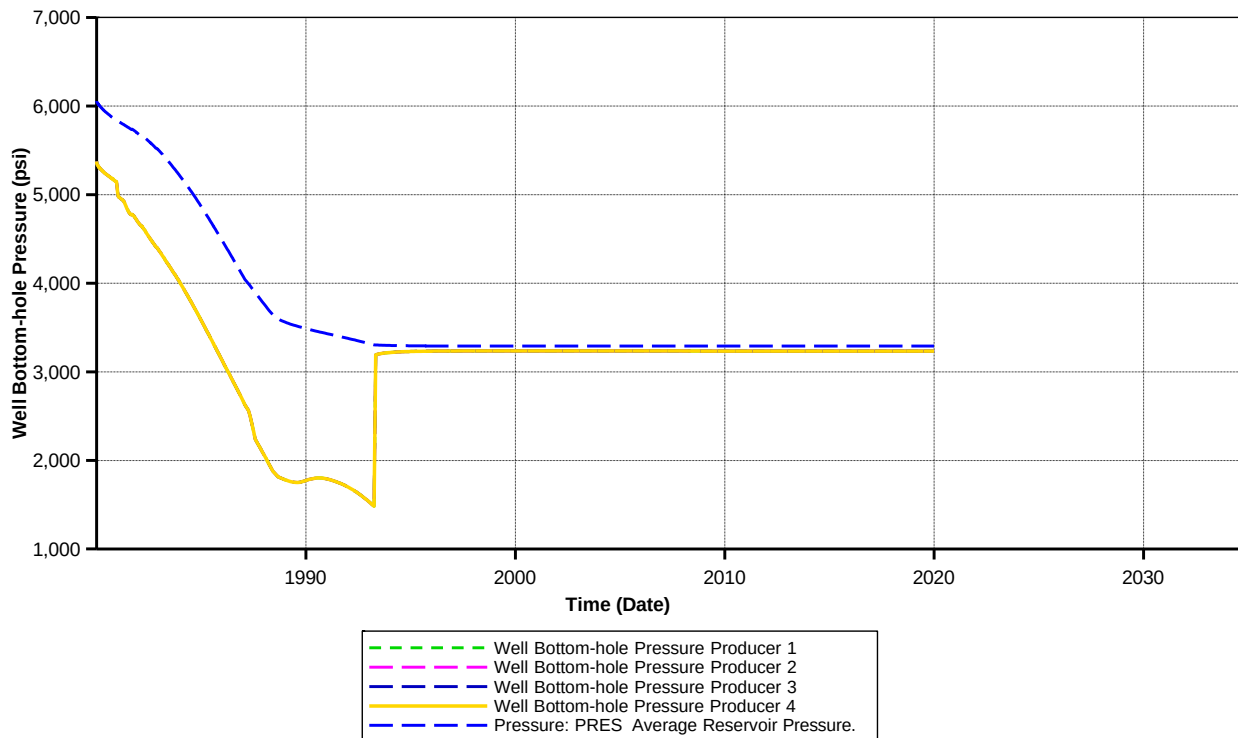


Figure 5.1: Relationship between average reservoir pressure and bottom-hole flowing pressure during the depletion period.

5.1.2 Reservoir Pressure Behavior after Water Injection

Water injection began in 1985, approximately three years before the reservoir pressure reached bubble point. The injection strategy was employed as a pressure support measure to mitigate the sharp decline caused by depletion. 6,000 barrels of water per day (b/d) were continuously injected into the injection well until 2018. An increase in pressure was observed, and the injection rate was reduced from 6,000 b/d to 4,000 b/d to prevent fractures due to the increased pressure.

Following the initiation of water injection, the average reservoir pressure initially continued to decline; however, the rate of pressure depletion decreased significantly compared to a depletion-only scenario. After several more months of injection, the pressure stabilized and even increased slightly. At the end of the simulation in 2020, the average reservoir pressure was approximately 5,374 psi, demonstrating the success of water injection in maintaining pressure.

The bottom-hole pressure (BHP) of the injector rose sharply at the start of injection due to the specific injection conditions and formation resistance, before stabilizing at a near-steady state. On the other hand, the bottom pressures of the production wells showed greater stability after injection, with a smaller pressure drop compared to the depletion period. This behavior underscores the role of water injection in maintaining reservoir pressure, limiting excessive pressure decline, and ensuring stable production.

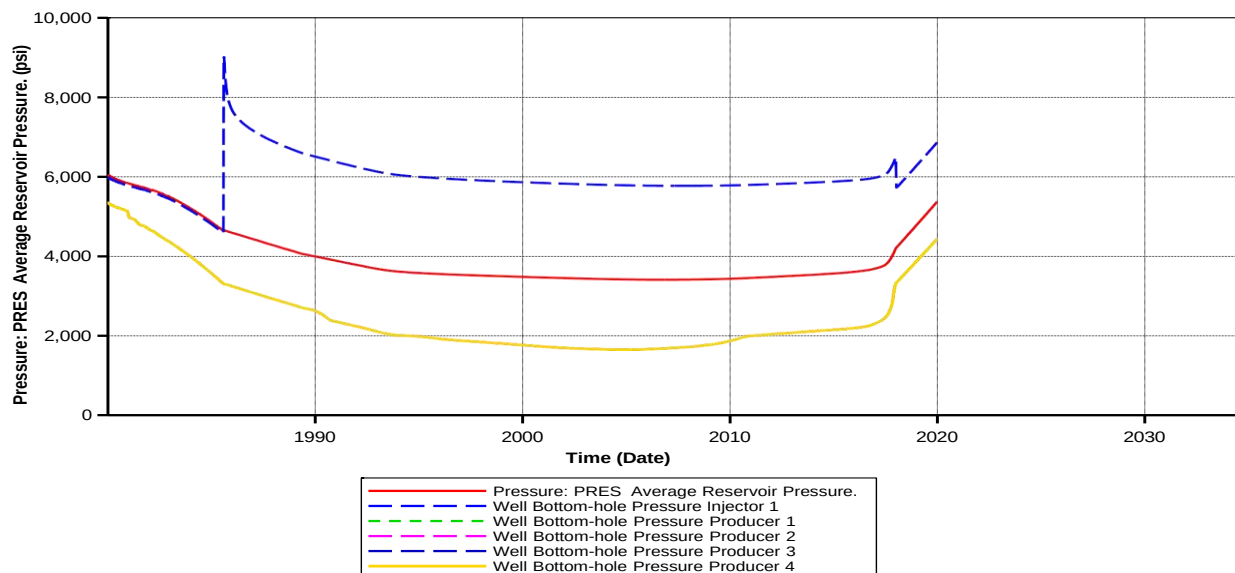


Figure 5.2: Reservoir and well bottom-hole pressure behavior before and after water injection.

5.2 Oil Production

5.2.1 Oil Production Performance Before Injection

Prior to the injection process, production from the reservoir began under natural depletion without external pressure support, relying entirely on the reservoir's natural energy. As production continued, fluid extraction from the reservoir led to a significant decrease in reservoir pressure, directly impacting the bottomhole pressure in the producing wells.

Pressure continued to decline until it approached the minimum allowable well operating pressure of 1,500 psi. Consequently, the producing wells were shut down at this level to prevent excessive pressure withdrawal and maintain reservoir integrity. Although a substantial amount of hydrocarbons remained in the reservoir, production ceased due to insufficient pressure. By the end of the depletion phase, total oil production in 1993 was approximately 10.645 million barrels out of a total of 242.31 million barrels. This equates to a recovery factor of approximately 4.4%. This recovery factor clearly demonstrates the limitations of natural depletion mechanisms in achieving sustainable production under continuously declining reservoir pressure. These findings underscore the need for an effective pressure enhancement strategy, such as pressure maintenance injection, to boost oil recovery and extend reservoir life.

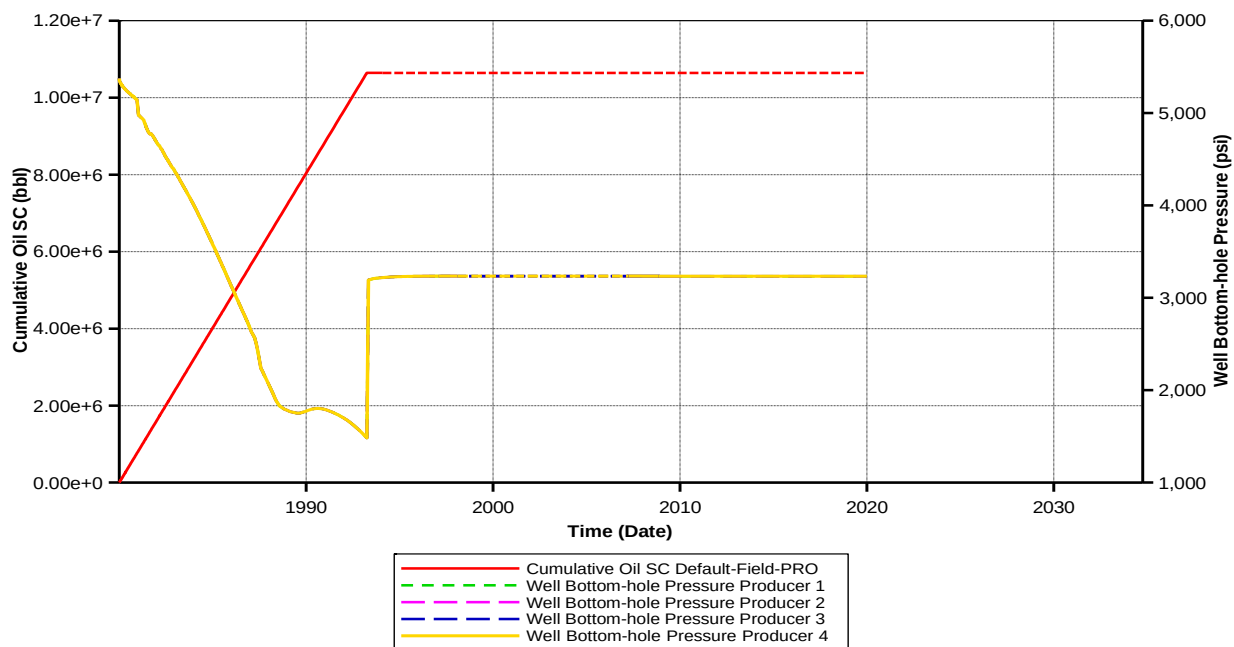


Figure 5.3: Cumulative oil production and bottom-hole flowing pressure behavior before water injection.

5.2.2 Oil Production Performance After Injection

Following the commencement of water injection, a significant improvement in reservoir performance was observed. Water injection began in 1985, approximately three years before the reservoir pressure reached the bubble point, at an injection rate of 6,000 barrels of water per day per injection well. In 2018, the injection rate was reduced to 4,000 barrels per day due to the increased pressure following water injection. Cumulative oil production continued to increase steadily, reaching approximately 32.142 million barrels by 2020, compared to approximately 10.645 million barrels before injection. The wells continued to produce at a rate of 550 barrels of oil per day per well, equivalent to 2,200 barrels of oil per day from the reservoir. This substantial increase reflects the effectiveness of maintaining the pressures provided by water injection.

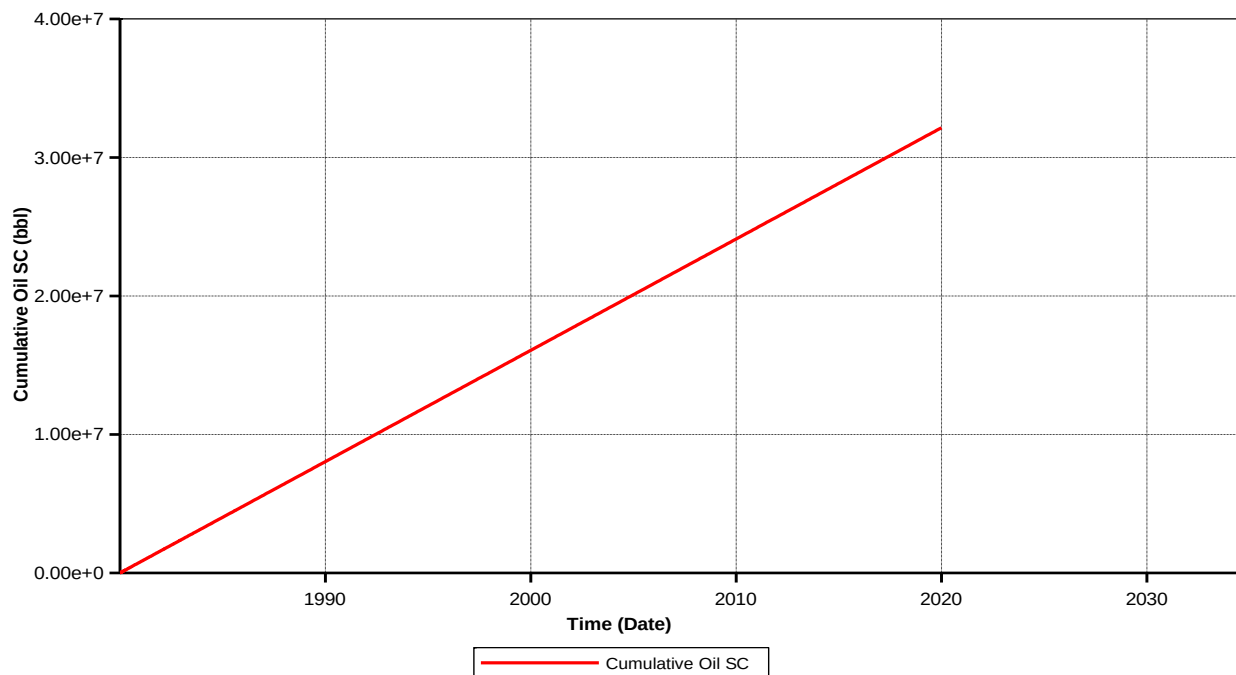


Figure 5.4: Cumulative oil production and well bottom-hole pressure behavior after water injection.

5.3 Recovery Factor Analysis

The recovery factor (RF) was evaluated to measure the effectiveness of the applied recovery strategy. During the depletion phase, total oil production was approximately 10.64 million barrels, reflecting an RF of approximately 4.4%, calculated from an initial reservoir volume (IOIP) of 242.31 million barrels. This relatively low RF highlights the challenges posed by natural depletion in maintaining reservoir pressure and supporting production over time.

After applying water injection, a significant improvement in recovery performance was observed. By the end of the simulation period in 2020, total oil production reached approximately 32.14 million barrels, resulting in an RF of approximately 13.3%. This higher RF demonstrates how water injection contributes to pressure support, maintaining well productivity, and enhancing sweep efficiency.

Overall, the RF increased by more than 2.6 times compared to the case where only depletion occurred, underscoring the fundamental importance of pressure maintenance activities in improving downstream oil recovery and extending the productive life of the reservoir.

$$RF = \frac{N_p}{OOIP} \times 100\% \dots\dots\dots(4)$$

Table5.1 Recovery factor analysis

Case	Cumulative Oil (MMSTB)	Recovery Factor (%)
Depletion	10.64	4.4
Water Injection	32.14	13.3

5.4 Water-Oil Ratio

5.4.1 Water-Oil Ratio Before Water Injection

Before water injection began, the water-to-oil ratio (WOR) was zero during the depletion phase, as shown in Figure 5.5. The WOR values indicate that oil production was devoid of any water production, demonstrating the absence of active support from the aquifer or water intrusion into the production wells.

These zero water-to-oil ratio behaviors suggests a depletion-driven production process, where energy is derived from the reservoir primarily through fluid expansion, without any external pressure support. Consequently, water production was not a limiting factor during the depletion phase, and the decline in well performance was mainly related to reservoir pressure drop rather than water intrusion.

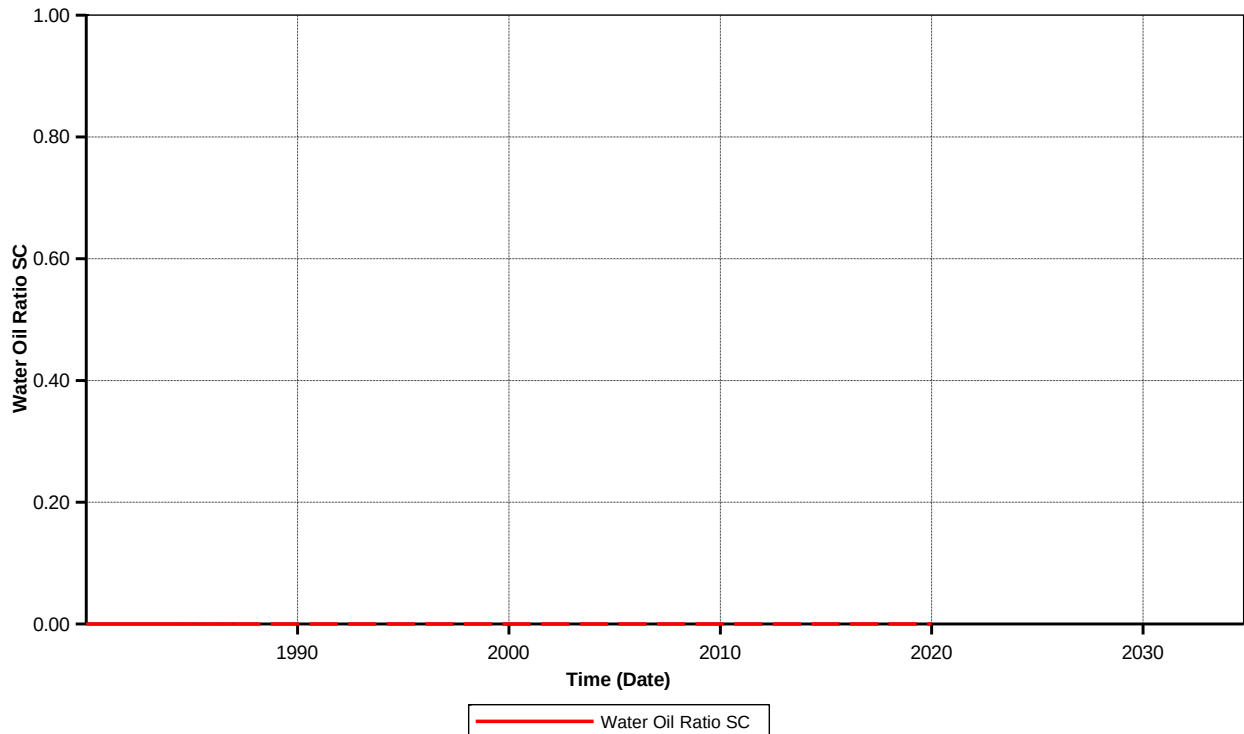


Figure 5.5.:Water-oil ratio (WOR) behavior before water injection.

5.4.2 Water-Oil Ratio After Water Injection

Following the initiation of water injection, the water-to-oil ratio (WOR) gradually increased as the injected water moved through the reservoir towards the production wells. As illustrated in Figure 5.6, the WOR began to rise several years after the injection, indicating the advancement of the displacement front in the reservoir.

Despite this observed increase, the WOR remained relatively moderate throughout the simulation period, approaching 0.014 by 2020. This slow rise in WOR suggests the absence of early water penetration, indicating a relatively stable displacement process with good sweep efficiency.

In summary, the managed rise in WOR indicates that the water injection strategy employed effectively supported pressure while maintaining acceptable water production levels, thereby enhancing oil recovery performance without requiring intensive water management

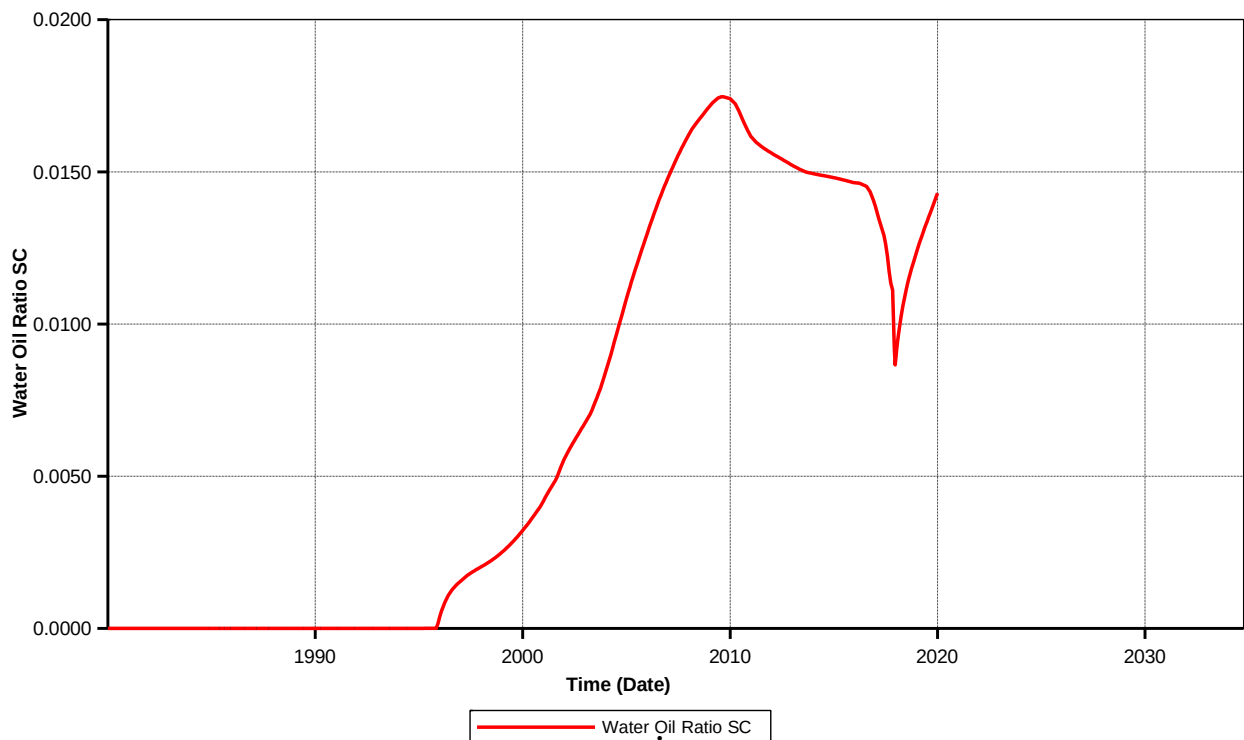
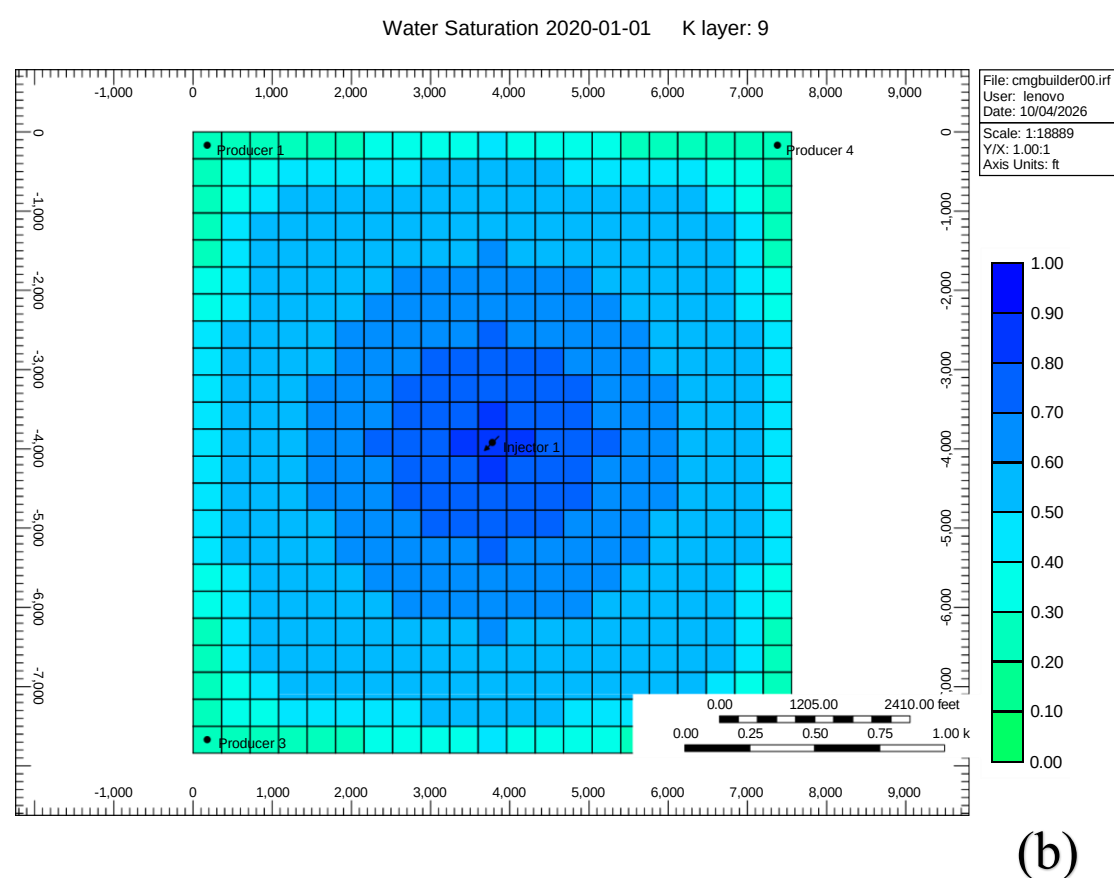
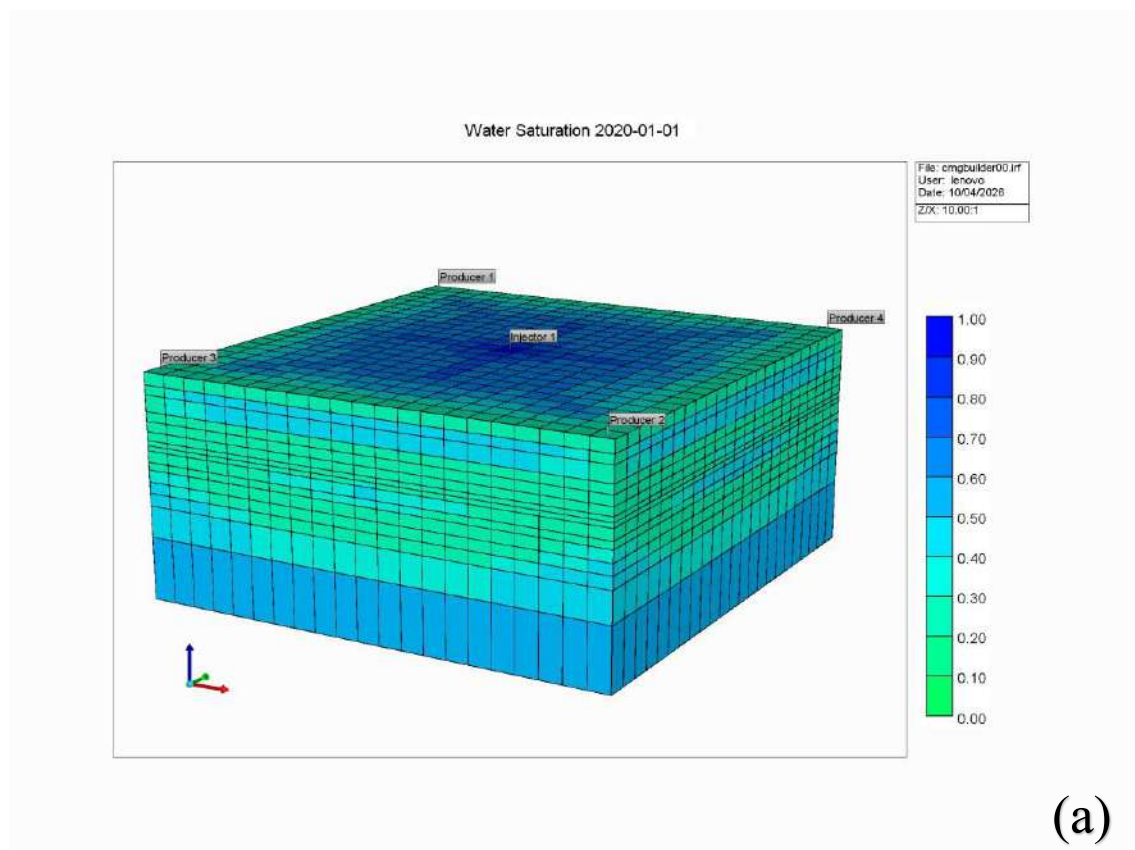
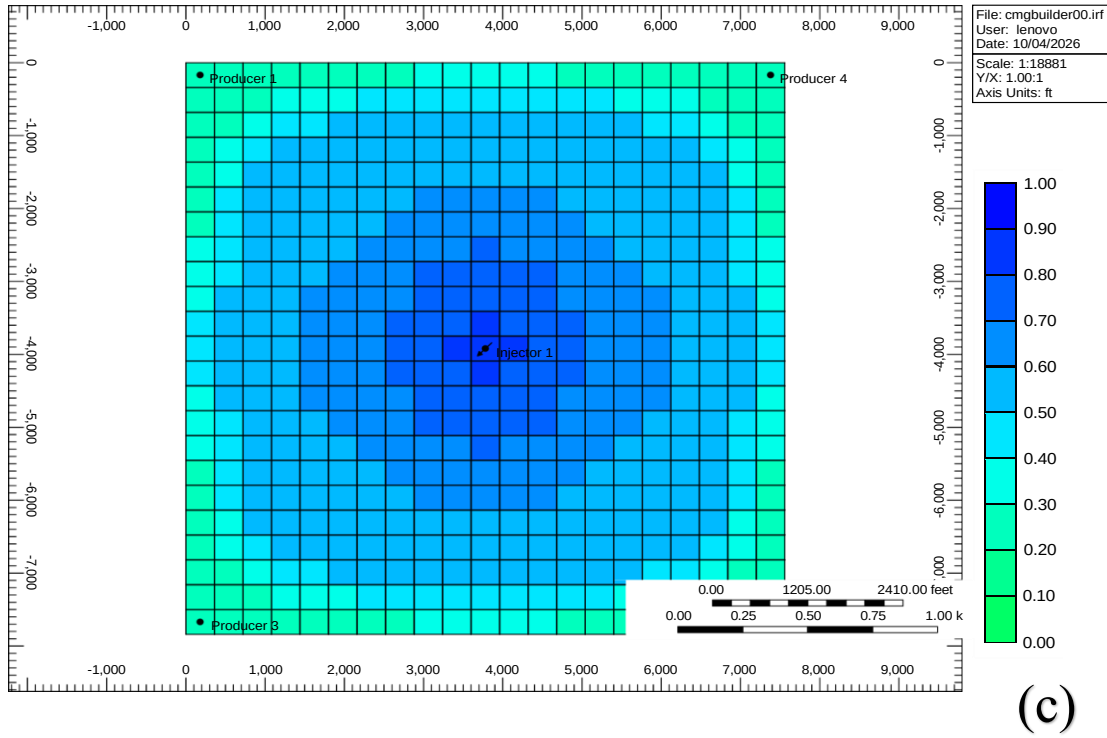


Figure 5.6: Water-oil ratio (WOR) behavior after water injection.



Water Saturation 2020-01-01 K layer: 10



Water Saturation 2020-01-01 K layer: 11

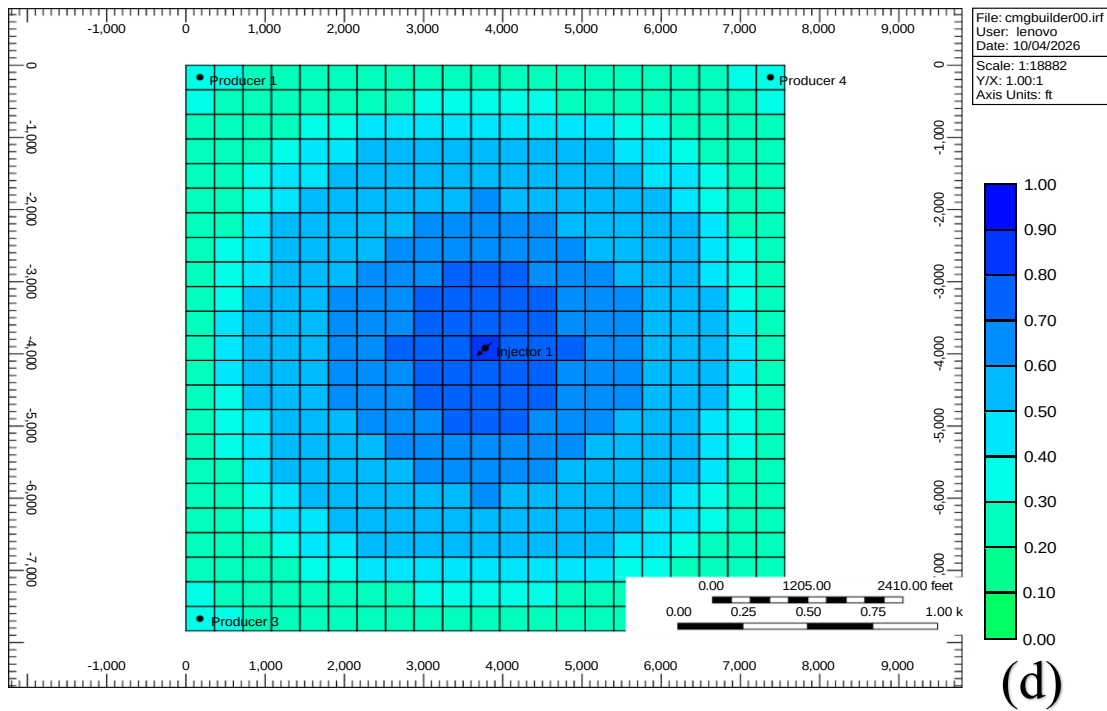


Figure 5.7:(a),(b),(c),(d) Water Saturation Distribution in a Reservoir Model

5.5 Gas-Oil Ratio

5.5.1 Gas-Oil Ratio Before Injection

The gas-oil ratio (GOR) behavior during the depletion phase shows a clear relationship with reservoir pressure decline. At the early stage of production, GOR values were relatively low, indicating that the reservoir pressure was above the bubble point and gas remained dissolved in the oil.

As production continued, a sharp increase in GOR was observed, reaching a peak of approximately 9400 ft³/bbl. around the late 1980s. This increase corresponds to the reservoir pressure dropping below the bubble point pressure, leading to gas liberation from the oil phase and the onset of free gas production.

The peak in GOR reflects intensive gas production and reduced oil mobility due to the expansion of free gas within the reservoir. After reaching this peak, GOR began to fluctuate and eventually declined sharply as the reservoir approached severe depletion and pressure dropped significantly.

This behavior indicates inefficient reservoir performance under natural depletion, where excessive gas production reduces oil recovery efficiency and leads to early production limitations. These results highlight the necessity of implementing pressure maintenance strategies, such as water injection, to control GOR behavior and improve overall recovery.

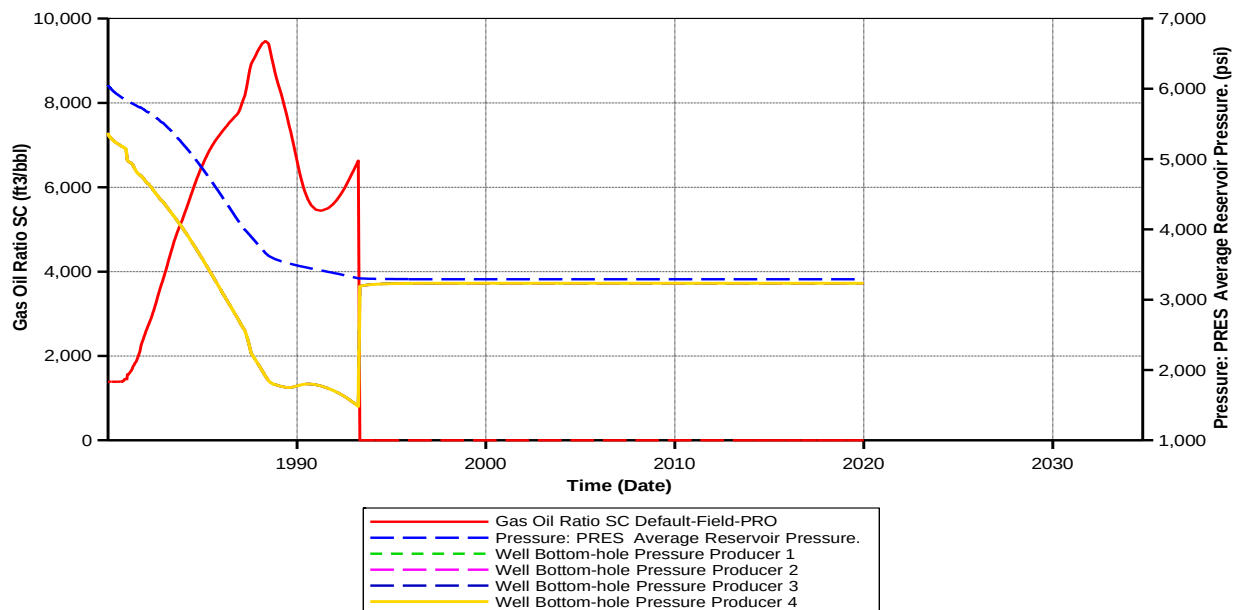


Figure 5.8: Gas-Oil Ratio (GOR) behavior during depletion period before water injection

5.5.2 Gas-Oil Ratio After Injection

The gas-oil ratio (GOR) behavior after water injection shows a significant improvement compared to the depletion case. Following the implementation of water injection, reservoir pressure was effectively maintained and gradually increased, as indicated by the pressure curve.

As a result of pressure support, the GOR exhibited a declining trend after reaching earlier peak values. Specifically, GOR decreased from values exceeding 7000 ft³/bbl. during depletion to approximately 1300–1400 ft³/bbl. in the later production period. This reduction indicates a decrease in free gas production due to improved pressure conditions.

The stabilization of GOR at lower values reflects a transition toward more efficient oil production, where gas liberation is minimized and oil mobility is improved. Additionally, the controlled behavior of GOR suggests that the reservoir remained closer to bubble point conditions, preventing excessive gas expansion.

Overall, the observed GOR trend after water injection confirms the effectiveness of pressure maintenance in enhancing reservoir performance. The reduction in GOR, combined with increased reservoir pressure, contributed to improved displacement efficiency and higher oil recovery.

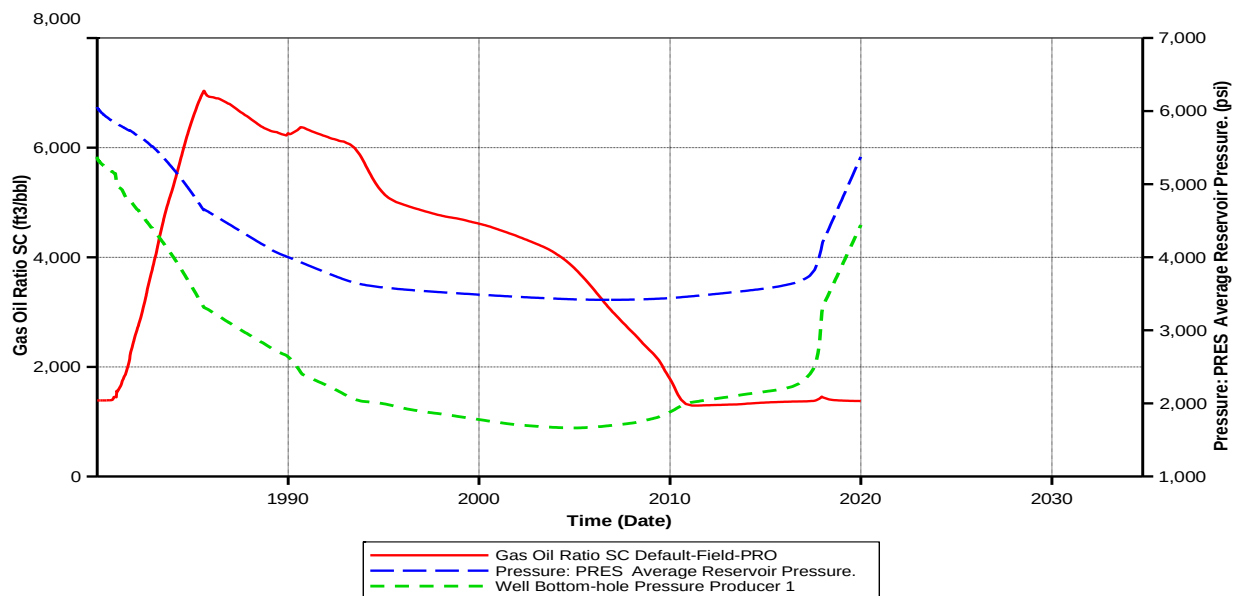


Figure 5.9: Variation of Gas-Oil Ratio (GOR) and Reservoir Pressure after water injection

5.6.1 Forecast Reservoir Performance to 2030

A predictive simulation was conducted to assess reservoir performance with continued water injection operations until 2030. The simulation results indicate that total oil production is expected to reach approximately 40.178 million barrels (cumulative) by 2030. This projection highlights the ongoing pressure support effect of the water injection method, as well as the extension of the reservoir's productive lifespan. During the forecast period, the average reservoir pressure is expected to increase to approximately 8,308 psi by 2030 as a result of the continued injection support. The flow pressure at the bottom of the production wells is expected to reach approximately 5,593 psi, while the bottom-hole pressure (BHP) in the injection system is expected to reach approximately 9,590 psi under varying injection conditions. Injection volumes were adjusted based on pressure increases. At the beginning of the reservoir's life, 6,000 barrels of water per day (b/d) were injected until 2018. Upon observing the pressure increase, the injection volume was reduced to 4,000 b/d. Results showed this volume to be effective. By 2021, the injection volume was further reduced to 3,500 b/d, and this volume was maintained until the end of the simulation period in 2030. This increase in reservoir and well pressures indicate the significant impact of continuous pressure management over the long operational life. Furthermore, the water-to-oil ratio (WOR) is expected to reach approximately 0.4715 by 2030. This suggests a gradual increase in water production as the injected water front moves through the reservoir, ensuring that production remains at satisfactory levels.

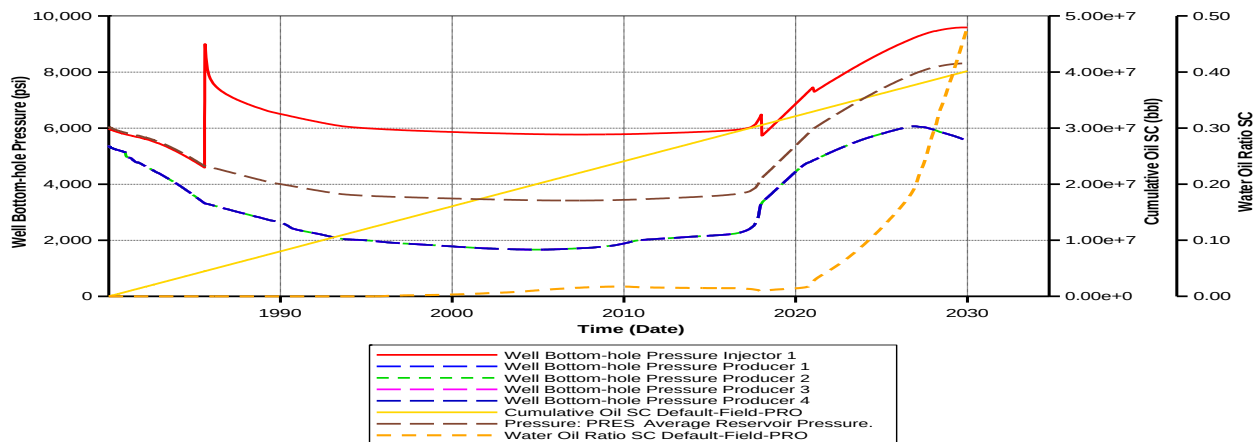


Figure 5.10. Forecasted cumulative oil production, average reservoir pressure, bottom-hole pressures, and water-oil ratio (WOR) up to 2030 under continuous water injection.

Furthermore, the water-oil ratio (WOR) is expected to reach approximately 0.4715 by 2030, reflecting increased water production as the injected water front advances through the reservoir.

In addition, the gas-oil ratio (GOR) stabilizes at approximately 1414 ft³/bbl by 2030. This stabilization indicates that reservoir pressure is effectively maintained near the bubble point pressure, reducing excessive gas liberation and ensuring more efficient oil production under continued water injection.

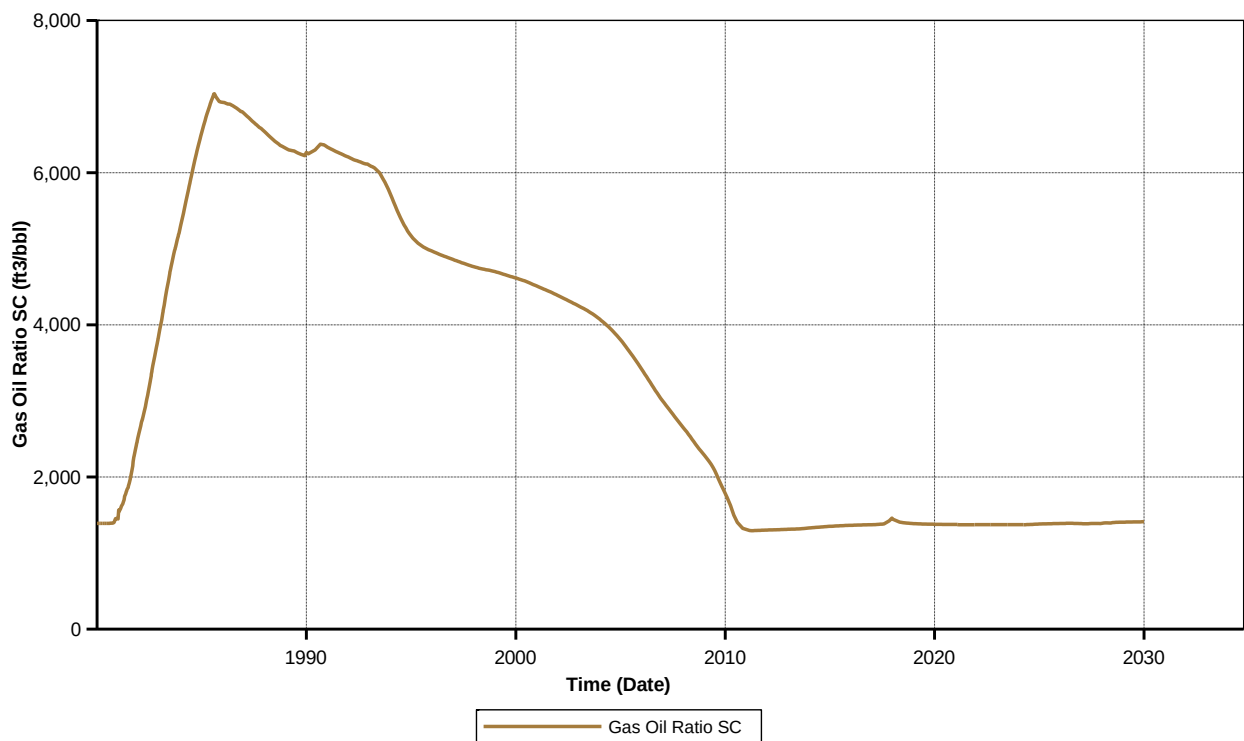


Figure 5.11 : Gas-Oil Ratio (GOR) behavior during depletion and water injection periods up to 2030

Table 5.2. Forecasted Reservoir Performance Parameters in 2030

Parameter	Forecasted Value (2030)
Cumulative Oil Production	40.178 million barrels
Average Reservoir Pressure	8308 psi
Producer Bottom-Hole Pressure	5593 psi
Injector Bottom-Hole Pressure	9590 psi
Water-Oil Ratio (WOR)	0.471538
Gas-Oil Ratio (GOR)	1411.4 ft ³ /bbl

5.6.2 Forecasting Model Limitations

Although the projected production trends are positive, it is important to recognize some limitations of the model. The simulation assumed an initial water injection rate of 6,000 barrels per day starting in 1985, without considering the economic constraints that typically influence field development decisions. These constraints include operating costs, oil price fluctuations, and water injection optimization strategies. Furthermore, the simulation model did not include fracture pressure limits, allowing injection to continue without restrictions on the maximum permissible reservoir or bottomhole pressure, resulting in the reservoir pressure exceeding the initial reservoir pressure by the end of the simulation. This explains why the reservoir pressure exceeds its initial value in the simulation model, which is mainly due to the absence of fracture pressure constraints and may not be realistic in actual field conditions. This omission led to relatively high projected pressure values towards the end of the forecast period. The reservoir model was also constructed using input data generated from simulations rather than a precise match with the field's historical production data. This approach introduces additional uncertainty into the long-term forecasts. The model also simplified the effects of variations in reservoir properties, as it relied on a uniform distribution of reservoir

characteristics, process variations, and surface facility constraints. Therefore, the forecast results should be viewed primarily as trends in technical performance indicating the effectiveness of water injection operations, rather than as precise predictions of field operations.

5.7 Overall Discussion of Results

A comparison between natural depletion and water injection scenarios clearly demonstrates the crucial role of pressure maintenance in enhancing reservoir performance. During the depletion phase, the reservoir experienced a steady decline in pressure, starting from approximately 6,000 psi and progressing to bubble point pressure. This led to decreased well productivity and the eventual shutdown of many production wells after they reached their minimum bottom-hole pressure. Consequently, oil production before injection was reduced, and the recovery rate was extremely low. Following the implementation of the water injection strategy in 1985, reservoir pressure stabilized, resulting in a significant reduction in the rate of pressure decline. The injected water effectively supported pressure, enabling production wells to operate under more stable bottom-hole pressure conditions and extending the reservoir's productive lifespan. As a result, total oil production increased significantly, and the recovery factor improved from approximately 4.4% during the depletion phase to nearly 13.3% with the application of water injection. Water-to-oil (WOR) analysis shows that despite a steady increase in water production after injection, the recorded WOR values remained within acceptable operating ranges. This indicates no significant early water penetration and that displacement efficiency remained adequate. This behavior demonstrates that the injection strategy employed improved reservoir sweep efficiency while keeping water production levels under control. Projections extending to 2030 indicate that cumulative oil production and reservoir pressure will continue to rise. However, the unusually high projected pressure values suggest flaws in the simulation assumptions, particularly regarding the lack of geomechanically fracture boundaries,

economic constraints on injection duration, and the optimization of the controlled injection rate. Therefore, while the projection provides a glimpse into the potential long-term effectiveness of the pressure-maintenance strategy, the results should be understood as a technical estimate and not a definitive description of the operating situation, as the focus was on the effectiveness of the reservoir injection performance.

In general, the combined analysis confirms that the immediate use of pressure support by water injection greatly improves reservoir pressure maintenance, enhances oil recovery, stabilizes well productivity, and extends reservoir production life compared to a strategy that focuses solely on depletion.

**Table 5.3. Production Performance Data of the Representative Production Well Before
Water Injection**

Well BHP (psi)	Water Oil Ratio SC	Cumulative Water SC (bbl)	Cumulative Oil SC (bbl)	Date
0	0	0	0	01/01/1980
5028.9	0	0	201300	01/01/1981
4682.31	0	0	402050	01/01/1982
4361.36	0	0	602800	01/01/1983
3999.32	0	0	803550	01/01/1984
3578.11	0	0	1.00E+06	01/01/1985
3125.22	0	0	1.21E+06	01/01/1986
2668.61	0	0	1.41E+06	01/01/1987
2061.36	0	0	1.61E+06	01/01/1988
1781.02	0	0	1.81E+06	01/01/1989
1773.39	0	0	2.01E+06	01/01/1990
1791.23	0	0	2.21E+06	01/01/1991
1699.79	0	0	2.41E+06	01/01/1992
1534.78	0	0	2.61E+06	01/01/1993
3217.65	0	0	2.66E+06	01/01/1994
3229.32	0	0	2.66E+06	01/01/1995
3233.45	0	0	2.66E+06	01/01/1996
3234.97	0	0	2.66E+06	01/01/1997
3235.47	0	0	2.66E+06	01/01/1998
3235.57	0	0	2.66E+06	01/01/1999
3235.53	0	0	2.66E+06	01/01/2000
3235.48	0	0	2.66E+06	01/01/2001
3235.43	0	0	2.66E+06	01/01/2002
3235.38	0	0	2.66E+06	01/01/2003
3235.33	0	0	2.66E+06	01/01/2004
3235.28	0	0	2.66E+06	01/01/2005
3235.23	0	0	2.66E+06	01/01/2006
3235.19	0	0	2.66E+06	01/01/2007
3235.14	0	0	2.66E+06	01/01/2008
3235.09	0	0	2.66E+06	01/01/2009
3235.03	0	0	2.66E+06	01/01/2010
3234.98	0	0	2.66E+06	01/01/2011
3234.93	0	0	2.66E+06	01/01/2012
3234.87	0	0	2.66E+06	01/01/2013
3234.81	0	0	2.66E+06	01/01/2014
3234.75	0	0	2.66E+06	01/01/2015
3234.68	0	0	2.66E+06	01/01/2016
3234.61	0	0	2.66E+06	01/01/2017
3234.55	0	0	2.66E+06	01/01/2018
3234.5	0	0	2.66E+06	01/01/2019
3234.46	0	0	2.66E+06	01/01/2020

Table 5.4. Production Performance Data of the Representative Production Well After

Well BHP (psi)	Water Oil Ratio SC	Cumulative Water SC (bbl)	Cumulative Oil SC (bbl)	DATE
0	0	0	0	01/01/1980
5028.900391	0	0	201300	01/01/1981
4682.306641	0	0	402050	01/01/1982
4361.361816	0	0	602800	01/01/1983
3999.323486	0	0	803550	01/01/1984
3578.105957	0	0	1004850	01/01/1985
3254.622559	0	0	1205600	01/01/1986
3092.70874	0	0	1406350	01/01/1987
2933.327148	0	0	1607100	01/01/1988
2776.471924	0	0	1808400	01/01/1989
2638.143555	0	0	2009150.125	01/01/1990
2368.5354	0	0	2209900	01/01/1991
2250.381348	0	0	2410650	01/01/1992
2116.925293	0	0	2611950	01/01/1993
2027.217773	0	0	2812700	01/01/1994
1996.484375	0	0	3013450	01/01/1995
1937.44104	0.000380242	9.077837944	3214200	01/01/1996
1892.063843	0.00154604	241.9762726	3415500	01/01/1997
1856.290894	0.002022847	609.0723877	3616250	01/01/1998
1818.495972	0.002500282	1063.832397	3816999.75	01/01/1999
1780.40918	0.003216792	1639.47229	4017750.25	01/01/2000
1741.576538	0.004190107	2387.125244	4219050	01/01/2001
1708.884888	0.005555141	3366.509277	4419800	01/01/2002
1688.650391	0.006740548	4614.822754	4620550	01/01/2003
1672.266113	0.008426921	6131.28125	4821300	01/01/2004
1665.345703	0.010824258	8086.232422	5022600	01/01/2005
1676.403809	0.012968183	10497.93066	5223350	01/01/2006
1701.534058	0.014791332	13307.29688	5424100	01/01/2007
1731.798096	0.016206037	16436.56641	5624850	01/01/2008
1787.47522	0.017145954	19806.95508	5826150	01/01/2009
1883.038208	0.017401554	23299.38281	6026900	01/01/2010
2010.503662	0.016169472	26671.21094	6227650	01/01/2011
2050.336182	0.015613639	29848.78125	6428400	01/01/2012
2087.3479	0.015212789	32947.92578	6629700	01/01/2013
2127.33667	0.014939992	35967.32031	6830449.5	01/01/2014
2162.603027	0.014807351	38952.10156	7031200	01/01/2015
2204.604492	0.014639802	41906.71484	7231950.5	01/01/2016
2317.036377	0.013866682	44810.33594	7433250	01/01/2017
3318.289551	0.00897388	47209.79297	7633999.5	01/01/2018
3882.412842	0.012388699	49445.99609	7834750	01/01/2019
4442.443848	0.014300006	52145.14063	8035500.5	01/01/2020

Tables 5.3 and 5.4 provide further confirmation of the patterns identified in the graphical analysis. According to Table 5.3, prior to the application of water injection, bottomhole pressures in the production wells declined significantly over time, causing production constraints and ultimately leading to well shutdowns. In contrast, Table 5.4 shows that after the initiation of water injection, well pressures became more stable and remained above the minimum operating pressure, facilitating continued oil production. Furthermore, the cumulative production figures in both tables demonstrate a clear increase in total oil recovery after the application of pressure support, confirming the success of the water injection method in improving overall reservoir efficiency.

Chapter Six

Conclusion and Recommendations

6.1 Conclusions

This research examined how reservoirs perform in two different development scenarios: natural depletion and pressure maintenance via water injection, utilizing numerical simulation with CMG IMEX. The results obtained clearly demonstrate, with quantitative data, the important effect of pressure support on the productivity of reservoirs and their long-term recovery effectiveness.

Throughout the depletion phase, the reservoir underwent a steady decrease in its average pressure from an initial level of about 6000 psi down to the bubble-point pressure of approximately 3600 psi. This decline resulted in diminished oil mobility, decreasing production rates, and the eventual cessation of well activity once the minimum bottom-hole flowing pressure limit of 1500 psi was attained. In this situation, total oil production amounted to around 10.64 million stock tank barrels (MMSTB), which relates to a recovery factor of nearly 4.4%. This outcome highlights the fundamental constraints associated with production that depends only on the natural energy of the reservoir.

After introducing water injection in 1985 at a rate of 6000 BWPD, the decrease in reservoir pressure was greatly reduced, and the pressures at the bottom-hole pressure (BHP) became stable, remaining above the operational limits. This maintenance of pressure allowed for continuous production and enhanced sweep efficiency throughout the reservoir. Consequently, total oil production grew significantly to around 32.4 MMSTB by the conclusion of the simulation period, elevating the recovery factor to nearly 13.3%, indicating an enhancement of over two times compared to the scenario involving only depletion.

The analysis of the water-oil ratio (WOR) showed a steady rise after the start of injection; nevertheless, the values stayed within acceptable operational boundaries. This indicates managed displacement behavior and the lack of significant early water breakthrough. The comparative study of production and pressure patterns clearly demonstrates that maintaining pressure via water injection is an effective method for improving reservoir performance and prolonging the productive lifespan of the field.

Forecasts extending to the year 2030 show ongoing rises in total production and reservoir pressure while injection conditions remain consistent. Nevertheless, the predicted pressure levels surpass practical operational expectations because of simplified models, which do not take into account geomechanical limits, fracture pressure restrictions, and economic optimization factors. Consequently, the long-term prediction should be understood as a scenario focusing on technical performance rather than a precise operational forecast.

In summary, the findings from the simulation indicate that initiating pressure-maintenance strategies early is crucial for enhancing oil recovery, ensuring well performance stability, and optimizing the long-term output of conventional oil reservoirs.

6.2 Recommendation

In light of the results from this study, the subsequent suggestions are put forward:

- ❖ It is highly advised to begin pressure-maintenance programs like water injection early to avoid significant drops in reservoir pressure and to ensure steady production rates.
- ❖ Future research should include economic analysis, considering factors such as injection expenses, oil price fluctuations, and the best timing and rates for injections to identify the most financially effective development strategies.

- ❖ It is advised to incorporate geomechanically limits and fracture-pressure constraints to enhance the accuracy of long-term pressure predictions and prevent the overestimation of possible reservoir pressure levels.
- ❖ Comprehensive sensitivity analyses regarding injection rates, spacing of wells, and the design of patterns must be performed to improve sweep efficiency and enhance overall recovery.
- ❖ When field data is accessible, it is important to conduct history matching to improve the dependability of the model and to enhance its ability to predict outcomes for long-term decisions regarding reservoir management.

The results of this study demonstrate that well-developed water injection programs are a technically sound and practically feasible approach to improving recovery efficiency and prolonging the productive lifespan of reservoirs.

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Reservoir porosity in Small Giant Bai Hassan Oil Field

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2025 - 2026

بِسْمِ اللَّهِ الرَّحْمَنِ الرَّحِيمِ
أَقْرَأْ بِاسْمِ رَبِّكَ الَّذِي خَلَقَ ﴿١﴾ خَلَقَ الْإِنْسَانَ مِنْ عَلَقٍ ﴿٢﴾ أَقْرَأْ وَرَبُّكَ
الْأَكْرَمُ ﴿٣﴾ الَّذِي عَلَّمَ بِالْقَلَمِ ﴿٤﴾ عَلَّمَ الْإِنْسَانَ مَا لَمْ يَعْلَمْ ﴿٥﴾

[سورة العلق ١-٥]

إهداء

إلى من كلَّه الوقار بالهيبة والقبول... إلى من أفنى عمره في سبيلي... والدي العزيز
إلى نبع الحنان ومصدر الأمان... إلى من دعت لي فاستجيبت دعواتها... والدتي الغالية
إلى سندي وعضدي في هذه الحياة... إخوتي وأخواتي
إلى أساتذتي الأفاضل الذين لم يخلوا علينا بعلمهم وتوجيهاتهم
إلى كل من ساندني بكلمة طيبة أو دعوة صادقة طوال مسيرتي الدراسية
أهدي إليكم ثمرة جهدي هذا

شكر وتقدير

...الحمد لله الذي بنعمته تتم الصالحات، والصلاة والسلام على معلم البشرية الخير، أما بعد
أتقدم بجزيل الشكر وعظيم الامتنان إلى عمادة كلية الهندسة وقسم هندسة النفط في جامعة
[الكتاب]، لما قدموه لنا من بيئة علمية محفزة طوال سنوات الدراسة
كما أخص بالذكر وبوافر التقدير مشرفتي الفاضلة [م.د. داليا كاميران]، التي لم تبخل علينا
بتوجيهاتها القيمة وملاحظاتها السديدة التي كانت لها الأثر الكبير في إتمام هذا البحث
ووصوله إلى شكله النهائي
والشكر موصول إلى كافة أساتذة القسم الذين نهلنا من علمهم، وإلى كل من ساعدني في
توفير البيانات الفنية والمصادر اللازمة لإنجاز هذا العمل
ختاماً، أسأل الله العلي القدير أن ينفع بهذا الجهد المتواضع ويجعله لبنة في بناء مستقبل
مشرق لبلدنا العزيز.

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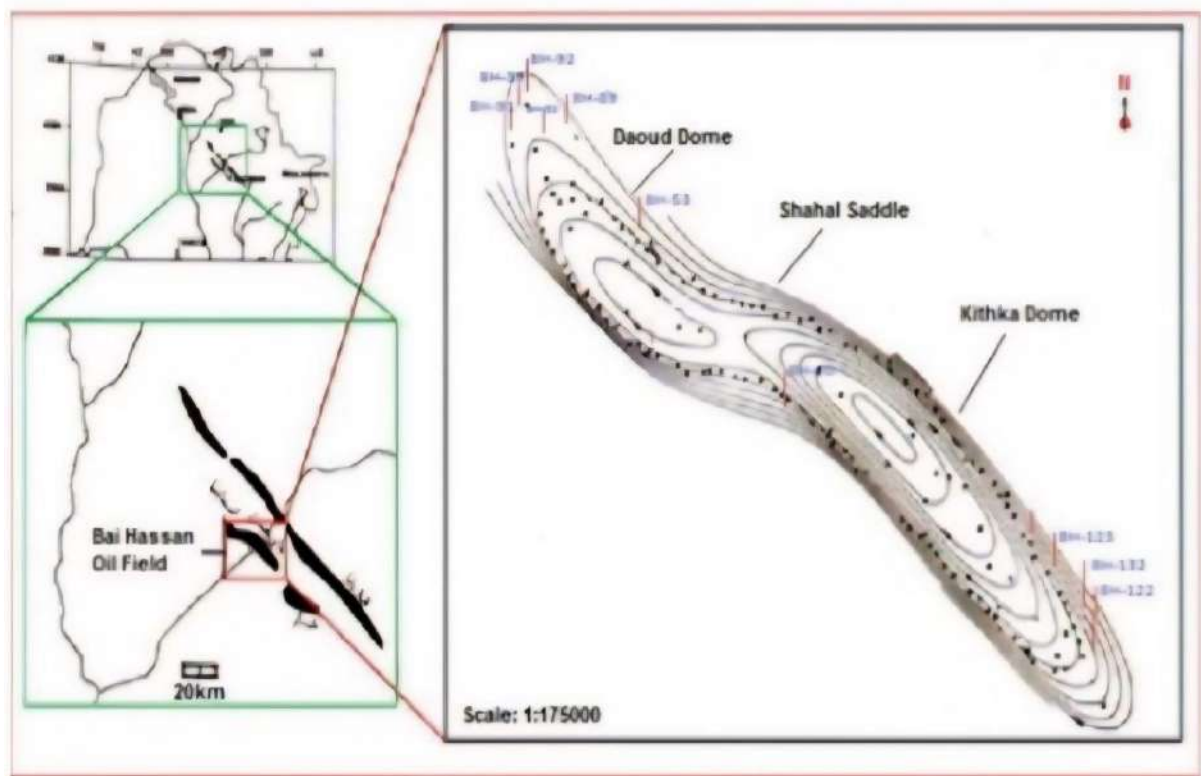
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INTRODUCTION

Preface:

The Bai Hassan oil field is considered one of the most important oil fields in northern Iraq. This small giant field is located near Kirkuk (Fig.1.1). The field has been discovered in 1953 by the Iraqi Oil Company (IPC) and started production in 1960 . The structure of the field is about 40 km long and about 3.5 km wide and consists of a longitudinal, sinusoidal, asymmetrical anticline. The southern limb of the structure is steeper and its slope about (37° - 65°) while the eastern limb slope is about (35° - 22°)



Aim of the Study:

Due to the lack of previous comprehensive studies on the small giant Bai Hassan Oil

The study is aimed to evaluate the

Following aspects:

Analysis of well log data, correction of data and
interpretation of petrophysical properties of rocks
to get accurate shale volume, effective porosity
and water saturation

Methodology:

- 1) Ten wells were chosen to cover the two saddles of the in Bai Hassan oil field (BH-20, BH-39, BH-50, BH-53, BH-89, BH-91, BH- 92, BH-122, BH-123, BH-132) (Fig.1.4).
- 2) Wireline logs of the ten wells sections include, Resistivity log (Deep Lateral Log LLD) Shallow Lateral Log LLS, Micro Spherical Focused Log (μ SFL), Compensated Neutron Log (CNL), Formation Density Compensated (FDC), Sonic log (DT) and Gamma Ray (GR).
- 3) Using Didger-3 software to digitize the well log data to determine each value we need to request the model
- 4) Using software (LogPlot-7 and Interactive Petrophysics V3.5) to draw The sections of each well

Well Log Calculation and Processes

1.Objectives:

This chapter focuses on deducing reservoir characteristics, including lithology, porosity types (primary and secondary), permeability, and fluid types from geologic logs. It specifically aims to determine water and oil saturation and subdivide the stratigraphic succession.

2. Study Scope:

The analysis covers ten boreholes from the Bai Hassan field, including BH-20, BH-39, BH-50, BH-53, BH-89, BH-91, BH-92, BH-122, BH-123, and BH-132.

3. Logging Tools Classification:

The parameters are derived from three main categories of logs:

Electric Logs: Spontaneous Potential (SP) and Resistivity (R).

Radioactive Logs: Gamma Ray (GR), Density (ρ_D), and Neutron (N).

Acoustic Logs: Sonic logs (DT).

The interpretation of well logs is

fundamentally influenced by specific rock properties, including lithology, porosity, mineralogy, and permeability, which dictate the tool's response. Furthermore, water saturation and sequence subdivision are critical for defining reservoir boundaries and fluid content. A key parameter in this process is rock resistivity, as it is measured directly and serves as an essential component in the quantitative evaluation of the reservoir

2.2 Sequence subdivision from geologic logs

Objective: Using logs for Sequence Stratigraphy and dividing layers into systems tracts

Gamma Ray (GR): The main tool for Lithology identification and correlation.

GR Interpretation: **Low GR:** Clean Sandstone / Carbonates.
High GR: Shale (high radioactivity).

Exception: "Clean" sand can show high GR if it contains Potassium Feldspar or Micas.

Shale volume calculation

Gamma ray logs was used in calculation of volume of shale in porous reservoirs. The volume of shale expressed as a decimal fraction or percentage is called V shale

Calculation of the gamma ray index is the first step needed to determine the volume of shale from a gamma ray log (Larionov,

$$I_{GR} = \frac{GR \log - GR \min}{GR \max - GR \min} \dots\dots\dots 2.1$$

.1969

I GR Gamma ray index

GR = gamma ray reading of formation

GR min = minimum gamma ray (clean sand or carbonate)

GR ma = maximum gamma ray (shale)

For a first order estimation of shale volume, the linear response, where(V IGg)

should be used. $V = 0.33 * (22 - GR)$ 2.2

On the basis of the following V_{sh} cut-offs, formations are regarded as clean, shaly, or shale zones:

1. $V_{sh} < 10\%$ implies a clean sand (Hilchie, 1978)
2. $V_{sh} 10-35\%$ implies a shaly sand
3. $V_{sh} > 35\%$ implies a shale zone (Ghorab et al., 2008)

Table 2.1: Types of wells logs, properties and use for geologic interpretations (Catuneanu, 2006).

Log	Property measured	Units	Geological interpretation
Spontaneous potential	Natural electric potential (relative to drilling mud)	Millivolts	Lithology, correlation, curve shape analysis, porosity
Conventional resistivity	Resistance to electric current flow (1D)	Ohm-meters	Identification of coal, bentonites, fluid types
Micro resistivity	Resistance to electric current flow (3D)	Ohm-meters and degrees	Borehole imaging, virtual core
Gamma ray	Natural radioactivity (e.g., related to K, Th, U)	API units	Lithology (including bentonites, coal) correlation, shape analysis
Sonic	Velocity of compressional sound wave	Microseconds/meter	Identification of porous zones, tightly cemented zones, coal
Neutron	Hydrogen concentration in pores (water, hydrocarbons)	Per cent porosity	Porous zones, cross plots with sonic and density for lithology
Density	Bulk density (electron density)(include pore fluid in measurement)	Kilograms per cubic meter (g/cm ³)	Lithologies such as evaporites and compact carbonates
Dipmeter	Orientation of dipping surfaces by resistivity changes	Degrees (azimuth and inclination)	Paleoflow (in oriented core), stratigraphic, structural analyses
Caliper	Borehole diameter	Centimeters	Borehole state, reliability of logs

Based on the Gamma Ray (GR) log trends and values in well BH-20 (Fig. 2.3), a significant variation in shale volume (V_{sh}) is observed within the Jeribe Formation. The formation exhibits high shale content ranging from 20% to 80%, indicating elevated natural radioactivity. Conversely, Unit B shows a distinct decrease in shale volume (1%–20%), reflecting a low concentration of radioactive clay minerals and a cleaner lithology

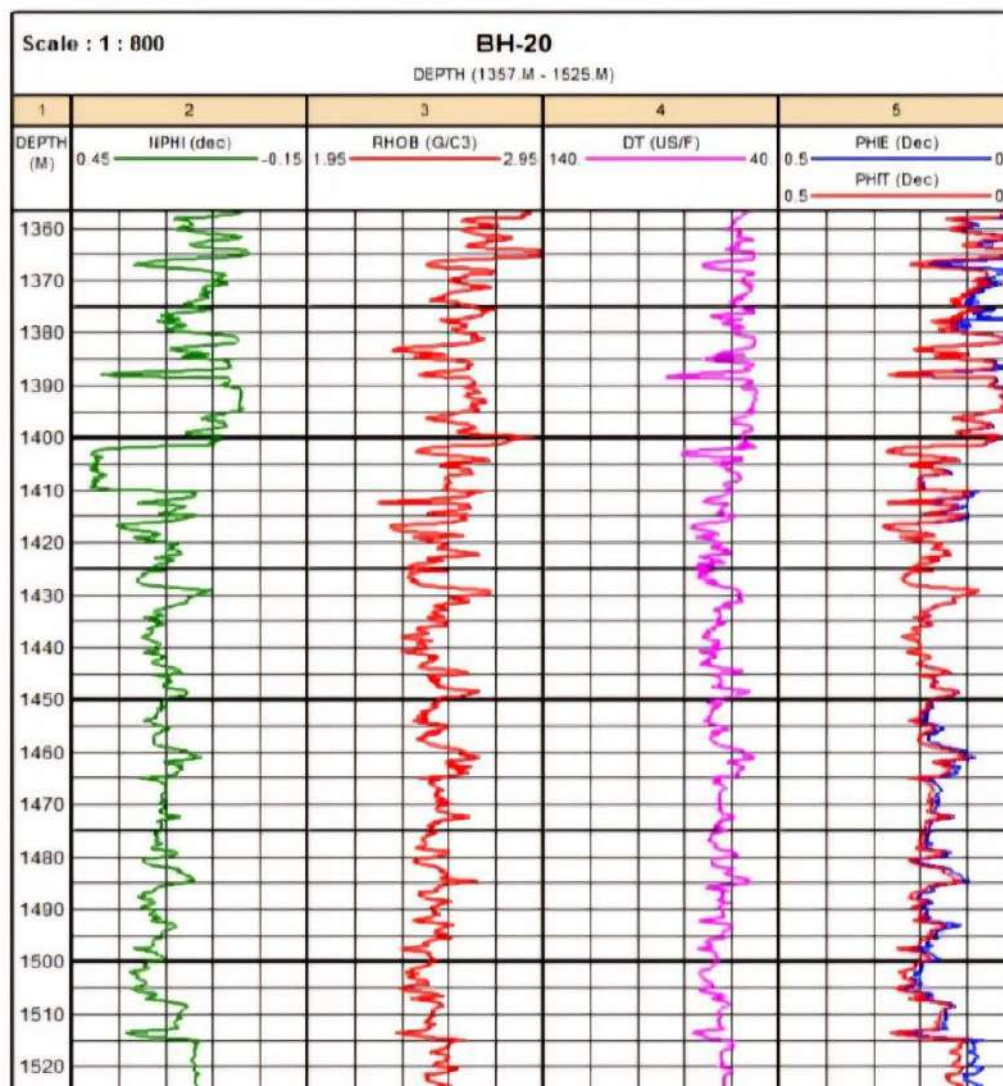


Fig.2.13: Neutron, Density and Sonic Logs, Response and calculated Effective Porosity in BH-20 With Depth (1357-1525m)

Analysis of the Gamma Ray log in well BH-53 (Fig. 2.6) reveals a high shale volume within the Jeribe Formation, ranging from 20% to 80%. Conversely, a significant reduction in shale content is observed in Units A, A", and B, where values drop to 1%–10%. This decrease reflects a cleaner lithology, highlighting these units as potential high-quality reservoir intervals

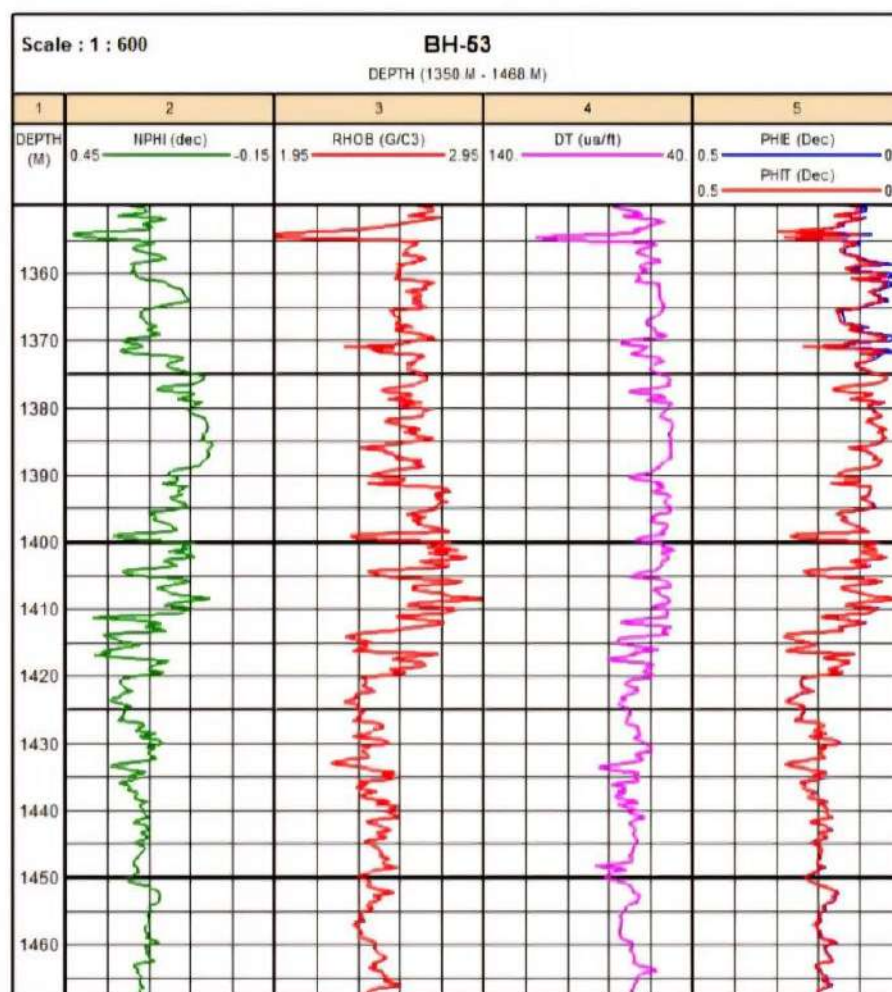


Fig.2.16: Neutron, Density and Sonic Logs, Response and calculated Effective Porosity in BH-53 With Depth (1350-1468m)

According to the clay volume results for well BH-122 (Fig. 2.10), the Jeribe Formation exhibits a wide range of shale content, fluctuating between 0% and 90%. Conversely, Units A" and B show significantly lower shale volumes, ranging from 1% to 20%, which indicates a cleaner lithology and potentially better reservoir quality in these specific intervals

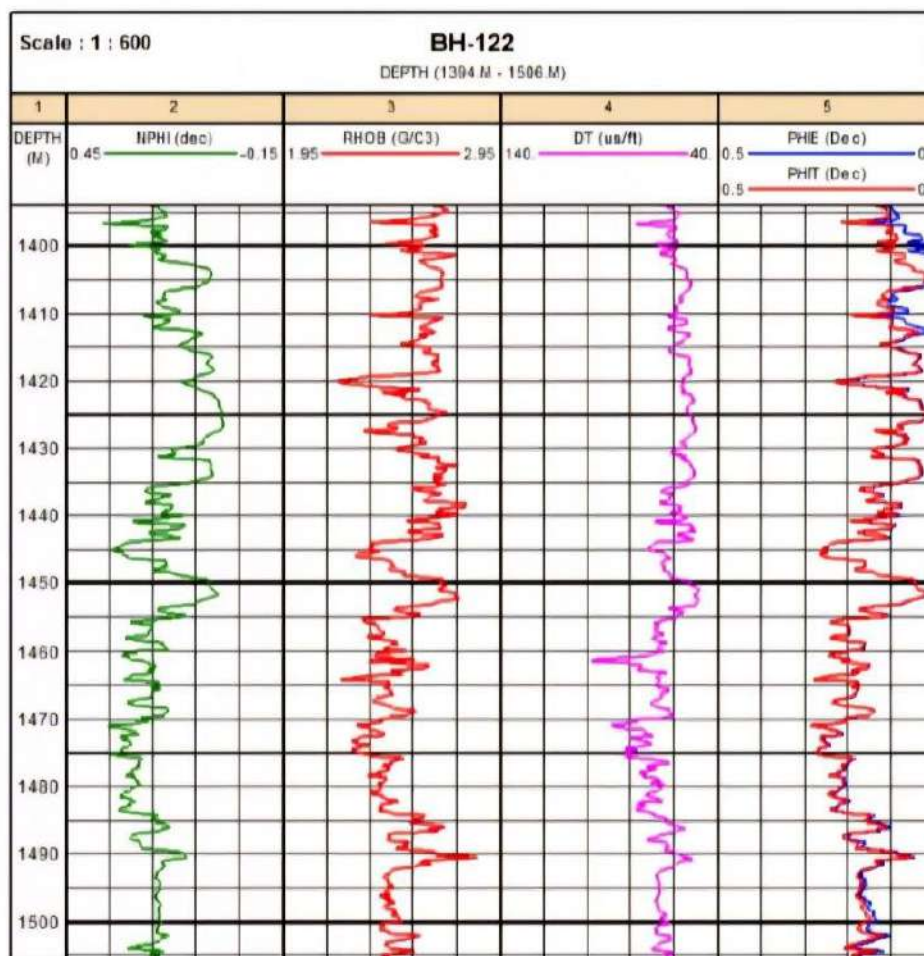


Fig.2.20: Neutron, Density and Sonic Logs, Response and calculated Effective Porosity in BH-122 With Depth (1394-1506m)

According to the clay volume results for well BH-123 (Fig. 2.11), high shale values are observed in both the Jeribe Formation and Unit B, with ranges fluctuating between 20% and 90%. In contrast, Units A" and A exhibit significantly lower shale volumes, ranging from 1% to 20%, highlighting their potential as cleaner lithological intervals

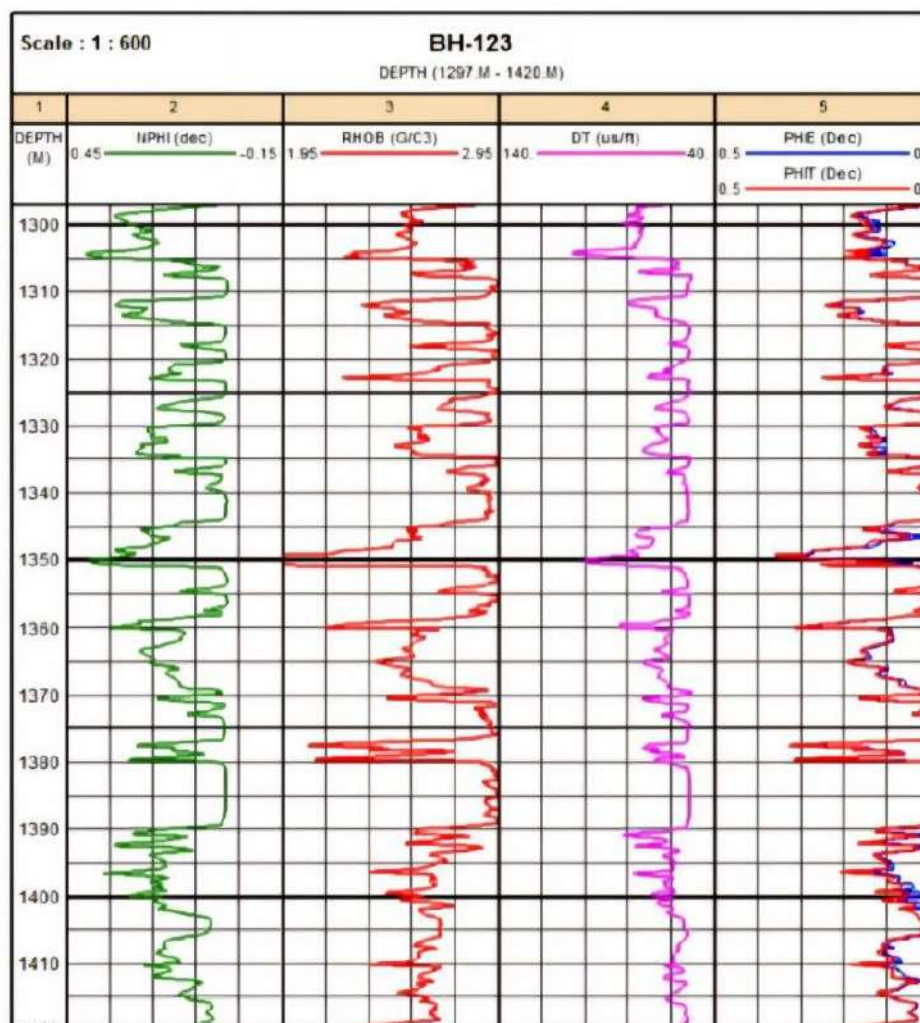


Fig.2.21: Neutron, Density and Sonic Logs, Response and calculated Effective Porosity in BH-123 With Depth (1297-1525m)

In well BH-132 (Fig. 2.12), the clay volume exhibits significant stratigraphic variation. The maximum clay volume is observed within the Jeribe Formation and Unit B, ranging between 1% and 85%. Conversely, the minimum clay volume is recorded in Unit A", with a narrow range of 5%–20%, identifying it as a relatively clean and stable interval

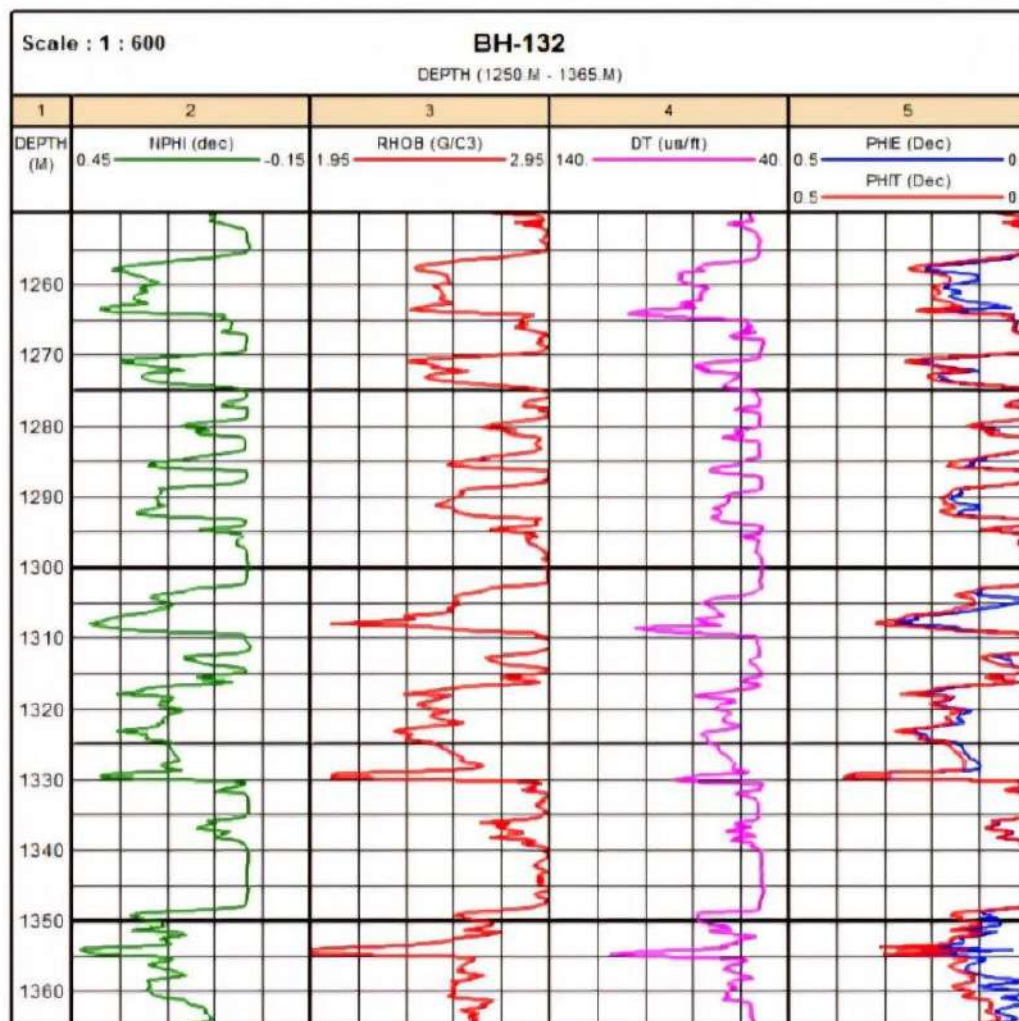


Fig.2.22: Neutron, Density and Sonic Logs, Response and calculated Effective Porosity in BH-132 With Depth (1250-1365m)

Porosity

1- Definition & Fundamentals:

Porosity : The percentage of a rock's total volume occupied by pore spaces.

Calculation: It is defined as pore volume divided by bulk volume. In carbonate reservoirs, averages range between 10% (Dolomite) and 12% (Limestone).

$$\Phi\% = \frac{\text{Pore volume}}{\text{Bulk volume}} \times 100$$

Total vs. Effective Porosity:

Total Porosity: Includes all void spaces (primary and secondary)

Effective Porosity: The interconnected pore space that allows fluid flow. It is the most critical parameter for engineers and is typically 5-10% less than total porosity.

3-Measurement Methods:

Logging Tools: Porosity is derived from Sonic, Density, and Neutron logs.

Calibration: Results must be cross-checked with laboratory core plug analysis for accuracy.

4-Reservoir Quality (Cut-off):

Commercial Range: Most reservoirs fall between 5% and 30%

Marginal Limit: Porosity below 5% is generally considered non-commercial unless enhanced by fractures or vugs

Table 2.2: Classification of porosity according to North (1985)

Type of porosity	%
Negligible	0-5
Poor	5-10
Fair	10-15
Good	15-20
Very good	20-25

Porosity log and lithological interpretation

(Sonic, Density, and Neutron) are essential for reservoir evaluation and reserve estimation. Calculating oil reserves requires precise data on formation thickness, porosity, and oil saturation. In complex carbonate reservoirs, combining multiple porosity logs is necessary to correct for variable lithology and matrix effects, ensuring more accurate interpretation within the flushed zone

Doveton (1999) emphasizes that true porosity calculation requires interpolation between matrix mineral values and pore fluid properties. Due to the shallow investigation of porosity tools, pore fluids are typically equated with mud filtrate within the flushed zone. Additionally, the presence of minerals like quartz, anhydrite, and gypsum must be accounted for to avoid errors in lithological interpretation

Density logs

Section 2.3.1.1 details the use of Density Logs to derive formation porosity

By measuring the bulk density (ρ_b) and comparing it to the matrix density (ρ_{ma}), porosity is calculated using the standard formula. For this study, a matrix density of 2.71 g/cm³ (standard limestone) was utilized. The density log is a primary indicator of reservoir quality, where lower bulk density values directly correlate with higher porosity zones

$$\Phi_{\rho} = \frac{(\rho_{ma} - \rho_b)}{(\rho_{ma} - \rho_{fl})} \dots\dots\dots 2.4$$

Where:

Φ_{ρ} = porosity by density log

ρ_{ma} = matrix density (in this study used standard limestone 2.71 g/cm³)

ρ_b = formation bulk density (the log reading)

ρ_{fl} = fluid density (salt water 1.16 g/cm³).

The matrix density can be calculated by flowing equation (Western Atlas, 1995) is: -

$$\rho_{ma} = \frac{\rho_b - \Phi_{N.D} * \rho_f}{1 - \Phi_{N.D}} \dots\dots\dots 2.5$$

$\Phi_{N.D}$: Neutron-density porosity

Sonic log

The Sonic Log measures the interval transit time to estimate porosity using the Wyllie time-average equation. In the Bai Hassan field study specific matrix values for limestone (47.6 $\mu\text{sec}/\text{ft}$) were applied. A critical consideration highlighted is the 'hydrocarbon effect,' which tends to artificially increase sonic porosity. To ensure accuracy, empirical corrections by Hilchie (1978) were utilized, applying a factor of 0.9 for oil-bearing zones to derive the true formation porosity

$$\Phi_S = \frac{\Delta t_{log} - \Delta t_{ma}}{\Delta t_{fl} - \Delta t_{ma}} \quad \dots\dots\dots 2.6$$

Where:

Φ_S = Sonic derived porosity.

$$\Delta t_{ma} = \frac{\Delta t_{log} - \Phi N.S * \Delta t_{fl}}{1 - \Phi N.S} \quad \dots\dots\dots 2.7$$

$\Phi N.S$ = Neutron- Sonic crossplot porosity

Table 2.3: Sonic Velocities and Interval Transit Times for Different Matrixes
(Schlumberger, 1972).

Lithology/Fluid	Matrix velocity ft/sec	Δt_{ma} or Δt_{ff} (Wyllie) $\mu\text{sec}/\text{ft}$ [$\mu\text{sec}/\text{m}$]	Δt_{ma} (RHG) $\mu\text{sec}/\text{ft}$ [$\mu\text{sec}/\text{m}$]
Sandstone	18,000 to 19,500	55.5 to 51.0 [182 to 168]	56 [184]
Limestone	21,000 to 23,000	47.6 [156]	49 [161]
Dolomite	23,000 to 26,000	43.5 [143]	44 [144]
Anhydrite	20,000	50.0 [164]	
Salt	15,000	66.7 [219]	
Casing (iron)	17,500	57.0 [187]	
Freshwater mud filtrate	5,280	189 [620]	
Saltwater mud filtrate	5,980	185 [607]	

$$\Phi = \Phi_s * 0.7 \text{-----gas} \dots\dots\dots 2.8$$

$$\Phi = \Phi_s * 0.9 \text{-----oil} \dots\dots\dots 2.9$$

Neutron Log

which measures hydrogen concentration to estimate fluid-filled porosity. To eliminate lithology effects, a combination of Density and Neutron logs is utilized. The study employs the square-root equation (Eq. 2.11) to suppress residual gas effects in the flushed zone. Finally, the effective porosity is determined by correcting the total porosity for shale volume (V) using Equation 2.13, ensuring a precise evaluation of the reservoir's

fluid-transmission capacity

$$\Phi_{N,D} = (\Phi_N + \Phi_D)/2 \dots\dots\dots 2.10$$

$$\text{Or } \Phi_{N,D} = [(\Phi_N^2 + \Phi_D^2)^{1/2}]/2 \dots\dots\dots 2.11$$

$$\Phi_{N,D} = \frac{1}{3} \Phi_N + \frac{2}{3} \Phi_D \text{ (in gas zone)} \dots\dots\dots 2.12$$

Where:

$\Phi_{N,D}$ = density and neutron properties combination

Φ_N = neutron porosity

Φ_D = density porosity

$$\Phi_e = \Phi_t * (1 - V_{sh}) \dots\dots\dots 2.13$$

Φ_e = effective porosity

Section distinguishes between primary and secondary porosity

While Neutron and Density logs respond to total porosity, the Sonic log is primarily sensitive to interparticle porosity and largely ignores vugs or fractures. Consequently, the Secondary Porosity Index (SPI) is calculated using Equation 2.14 as the difference between the combined Neutron-Density porosity and Sonic-derived porosity. Field observations indicate that secondary porosity, often caused by vugs, remains minimal in the studied sections.

To calculate the secondary porosity, we use the equation below by Schlumberger (1997): -

$$SPI = (\Phi_{N,D} - \Phi_s) \dots\dots\dots 2.14$$

SPI = Secondary porosity index

$\Phi_{N,D}$ = density neutron porosities combination

Φ_s = sonic-derived porosity

Water Saturation Archie method

Archie (1942) showed that the resistivity of a water filled formation (R_o) could be related to the resistivity of the water (R_w) filling the formation through a constant called the formation resistivity factor (F).

$$R_o = F * R_w \dots\dots\dots 2.16$$

Archie also revealed that the formation factor (F) could be related to the porosity of the formation by the following formula:

$$F = \frac{a}{\Phi^m} \dots\dots\dots 2.17$$

By combining equations 4.16 and 4.17 the water saturation formula can be rewritten in the following form:

$$S_w = [(a * R_w) / (R_t * \Phi^m)]^{1/n} \dots\dots\dots 2.18$$

Where:

S_w = water saturation of uninvaded zone

a = tortuosity factor ($a = 1.0$ for carbonate rocks)

m = cementation exponent ($m = n = 2.0$)

n = saturation exponent

R_w = resistivity of formation water ($R_w = 0.035$ ohmm)

Evaluation of True Resistivity and Invasion Effects

This part of the research addresses the technical challenges in determining the True Formation Resistivity (R_t) and the physical impact of drilling fluid invasion on log measurements.

Key Technical Points:

Logging Tool Limitations: The study identifies that standard Deep Induction Logs may not provide accurate readings in thin, highly resistive zones (where $R_t > 100$ ohm-m).

The $R_{t \min}$ Alternative: To maintain data integrity in such conditions, the R_t minimum ($R_{t \min}$) technique is applied using the following relationship:

$$R_{t \min} = R_i \cdot (R_w / R_{mf})$$

Rrepresents the resistivity of the invaded zone, typically measured by a Laterolog-8 or spherically focused log.

Fluid Displacement (Invasion): The text

explains the process where drilling mud filtrate (R_{mf}) invades porous and permeable formations, displacing the original formation water. For the calculations in this study, the R value is set at 0.65 ohm-m, following Schlumberger (1979) standards.

Shallow Resistivity (R): It establishes that porosity in water-bearing formations is directly related to the shallow resistivity recorded in the flushed zone.

Conclusion:

By implementing these corrective methods, the research ensures a more reliable estimation of reservoir fluid saturation, accounting for the environmental changes caused by the drilling

process near the well

$$S_{xo} = [(a * R_{mf}) / (R_{xo} * \Phi^m)]^{1/n} \dots\dots\dots 2.20$$

S_w = water saturation in the flushed zone

R_w = flushed-zone resistivity

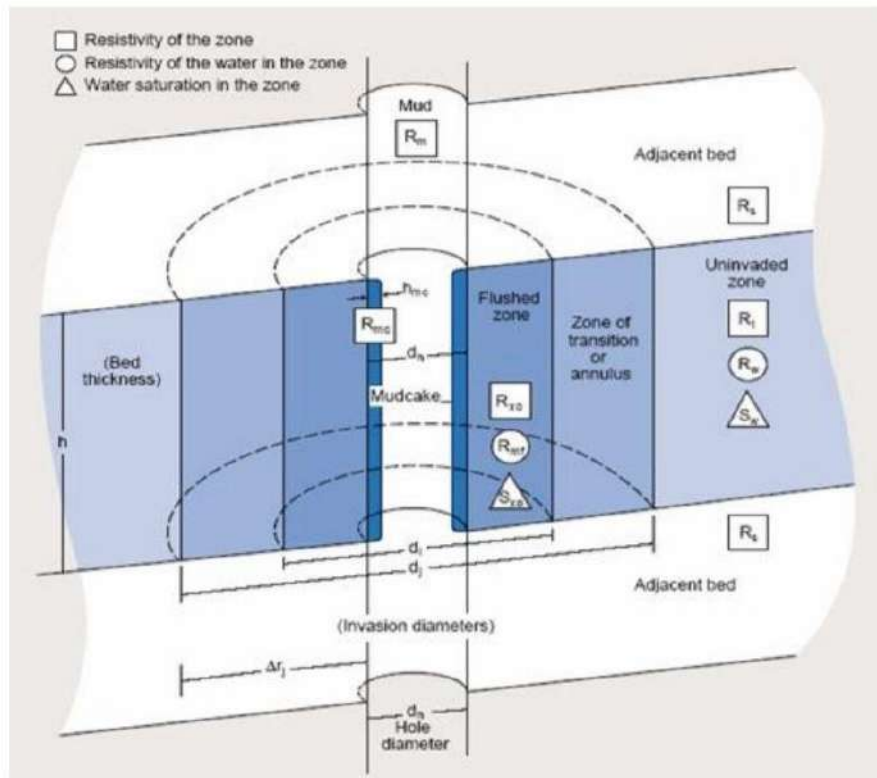


Fig.2.33: Borehole environment and symbols used in log interpretation (Schlumberger, 1998).

Hydrocarbon Saturation Modeling (S4)

This section describes the geostatistical workflow for distributing hydrocarbon saturation within the reservoir model. By utilizing the Sequential Gaussian Simulation (SGS) algorithm, the study ensures consistency with the porosity model. Key spatial parameters include a 5000m variogram range for horizontal directions and an exponential variogram modeling to capture the spatial continuity of the interpreted log data. This approach allows for a realistic 3D representation of hydrocarbon distribution across the field.

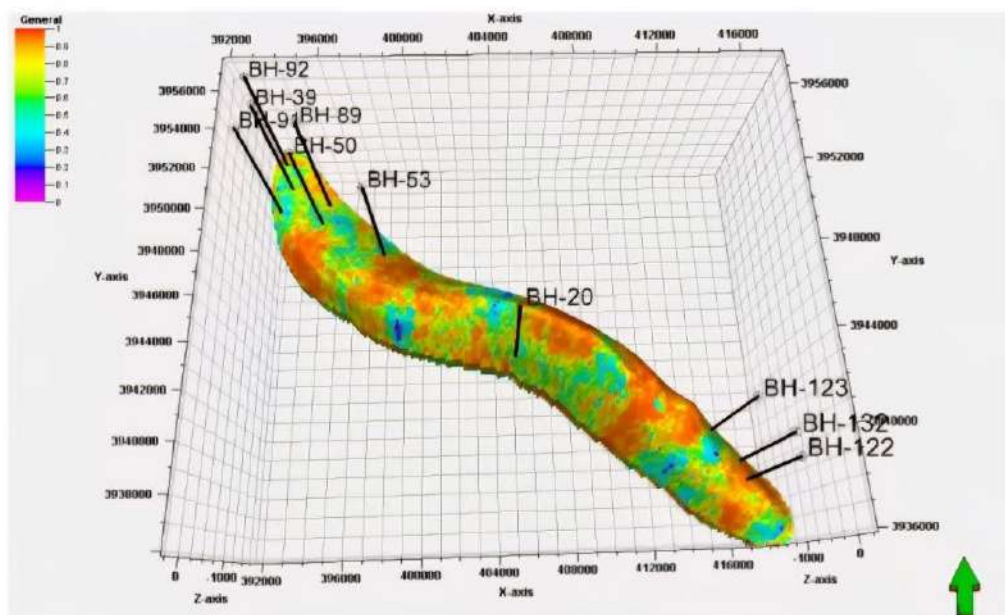


Fig. 5.13: 3D Constructive Model Showing Distribution of Hydrocarbon Saturation in Bai Hassan Oil Field

Figure 5.13 shows the hydrocarbon saturation model for Tertiary period formations for Tertiary period formations in the small giant Bai Hassan oil field. It is clear that has very high hydrocarbon value in the most parts of the field (brown zone). In BH-53, BH-89, BH-92, BH-122 and BH-132 wells that locating in this region the hydrocarbon saturation ranges between (75%-95%). While in the other parts of the field the hydrocarbon distribution has medium values (blue and green zone), which are ranges from (40%-70%). The wells BH-20, BH-39, BH-50, BH-91 and BH-123 are located in this region

Discussion

1. Reservoir Quality Determination Based on Shale Volume

Discussions revealed a significant variance in shale content within the **Jeribe Formation**. Percentages in some wells ranged between **20% and 80%**, whereas other units, specifically **Unit A and Unit B**, showed a marked decrease in shale volume (**1% to 20%**). This indicates that these units represent high-quality reservoir intervals characterized by cleaner lithology.

2. Porosity Assessment and Hydrocarbon Effects

The research emphasized the importance of integrating various porosity logs (Sonic, Density, and Neutron) to correct for lithological effects. The "**Hydrocarbon Effect**" was noted, which causes a false increase in sonic porosity. This necessitated the use of empirical corrections (using a factor of **0.9**) for oil-bearing zones to ensure the accuracy of the calculations.

3. Secondary Porosity Index (SPI) Analysis

The study discussed the distinction between total and effective porosity. The **Secondary Porosity Index (SPI)** was calculated as the difference between (Neutron-Density) porosity and Sonic porosity. Field observations indicated that secondary porosity resulting from **vugs** remained negligible within the studied sections.

4. Resistivity Measurement Challenges

The research addressed technical difficulties in determining the **True Formation Resistivity (R_t)** in thin, high-resistivity zones. It discussed methods for mitigating the effects of **mud filtrate invasion** to ensure a reliable estimation of fluid saturation within the reservoir.

5. Hydrocarbon Saturation Modeling

Three-dimensional modeling using the **Sequential Gaussian Simulation (SGS)** algorithm revealed high hydrocarbon distribution across most parts of the field. Saturation levels in wells such as **BH-53** and **BH-122** ranged between **75% and 95%**, while other areas recorded moderate values ranging from **40% to 70%**.

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Effect of temperature and pressure on drilling mud filtration properties

A research paper submitted to the Department of petroleum engineering, in partial fulfillment of the requirements of the degree of bachelor of Science in petroleum engineering.

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April 2026

Dedication:

- Our parents and brothers who have always supported us and thanks to their efforts we have reached this day.
- Dedicated to our friends who helped us.



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Thanks to Allah for giving us the ability to complete this research. We thank our family for their continued support and cooperation. We would like to thank our supervisor (Dr.Fryad Mohammed Sharif) for his guidance and discussion. Thank you to all our teachers who taught us during our studies and thank you to all those who helped us with a word, we wish them success. Immense thanks to the Head of College of engineering , Department of petroleum engineering



Abstract

This research focuses on the effect of temperature and pressure on the filtration properties of water-based drilling fluids under high-temperature and high-pressure (HTHP) conditions. The results indicate that increasing temperature has a significant impact on drilling fluid behavior by reducing fluid viscosity, which directly increases filtrate loss. This shows that thermal conditions play a key role in controlling filtration performance.

The study also demonstrates that pressure fluctuations strongly influence filtration characteristics. Higher pressure increases the driving force for fluid invasion into the formation, which contributes to greater filtrate volume and affects the development of the filter cake.

In addition, the results show that thermal aging under high-temperature conditions leads to degradation of drilling fluid properties, which reduces the efficiency of fluid-loss control additives. This contributes further to increased filtration rates and changes in filter cake thickness.

The findings also highlight that an optimized particle size distribution (PSD) is essential for forming a thin, compact, and low-permeability filter cake. Such a filter cake is important for minimizing fluid loss and maintaining wellbore stability. Overall, the results indicate that proper control of temperature, pressure, and drilling fluid composition is necessary to ensure effective filtration control and safe drilling operations in HTHP environments.

Keywords: Drilling Fluids, Water-Based Mud, HTHP (High-Temperature High-Pressure), Filtration Loss, Filter Cake, Wellbore Stability, Rheology, Bentonite.



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Abbreviations and Symbols:

Symbol / Abbreviation	Definition	Unit
API	American Petroleum Institute	
HTHP	High Temperature High Pressure	
WBM	Water-Based Mud	
OBM	Oil-Based Mud	
ROP	Rate of Penetration	
MWD	Measurement While Drilling	
LWD	Logging While Drilling	
PV	Plastic Viscosity	
YP	Yield Point	
AV	Apparent Viscosity	
PSD	Particle Size Distribution	
CMC	Carboxymethyl Cellulose	
PAC	Polyanionic Cellulose	
T	Temperature	°C / °F
P	Pressure	psi / Pa
ΔP	Differential Pressure	psi / Pa
V _f	Filtrate Volume	mL (cm ³)
t	Time	min / s
μ	Dynamic Viscosity	cP (Pa·s)
k	Permeability	mD (millidarcy)
A	Filtration Area	cm ²
Q	Flow Rate	mL/min
C	Filtration Constant	mL/ $\sqrt{\text{min}}$
h	Filter Cake Thickness	mm

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Chapter One

1.1 Background

In petroleum engineering, geothermal energy development, and the oil and gas sector, drilling operations are essential tasks. Maintaining wellbore stability, managing formation pressure, and guaranteeing effective removal of drilled cuttings are all critical to the success of any drilling operation. Drilling fluids, or drilling mud, are essential to accomplishing these goals. Controlling filtration qualities is one of their many roles, especially in high-temperature and high-pressure (HTHP) situations [1].

Bottom-hole temperature and formation pressure grow dramatically with increasing drilling depth. The viscosity, density, rheology, and filtration behavior of drilling fluids are among the physical and chemical characteristics that are directly impacted by these modifications. Temperatures and pressures in deep and ultra-deep wells can surpass 150 to 300°C and several thousand psi, respectively. Conventional drilling fluids may perform worse in such circumstances because of the compression of the filter cake, changes in clay hydration, and heat deterioration of the additives [2].

Because too much fluid loss into permeable formations can result in differential sticking, wellbore instability, formation damage, and decreased productivity, filtration management is crucial. Therefore, one of the main goals of drilling fluid design is the creation of a thin, stable, and low-permeability filter cake. However, changes in temperature and pressure have a big impact on the properties of the filter cake and the filtrate volume. Optimizing drilling fluid compositions and enhancing drilling performance in difficult conditions require an understanding of these impacts [3].

1.2 Temperature during Drilling:

Drilling is used for a number of tasks, such as making holes for explosives used in rock blasting in the building, mining, and oil and gas sectors. Three well-known drilling techniques are used in the mining industry, There are three different types of drilling: percussion, rotary, and rotary-percussive. Notably, rotary drilling plays a big role in underground metal mines and large open-pit mines, particularly in production drilling. As drilling continues, The temperature inside the drill bit and the rock increases by a few degrees Celsius, depending on the rock's properties, drilling time, and operational factors. In this regard, [20] carried out a thorough assessment of the PDC cutter-rock contact during drilling and rock cutting operations. Numerous temperature measurement methods have been established, originating from the rock drilling and metal machining industries. Conventional measures from metal machining operations, such infrared radiation pyrometers and implanted thermocouples, have been adapted to rock cutting with very slight alterations. [21] investigated sample drilling temperature at high vacuum settings by contrasting the Fiber Bragg grating temperature monitoring method with a one-dimensional transient heat transfer model. The findings showed excellent agreement between estimates. and experimental findings, emphasizing how the model takes heat sources, drill bit configuration, and radiation effects into account [4].

Using test research on thermal drilling models, a numerical model for the warming process on the working face during drilling was developed and validated. The dependability of numerical simulation results was demonstrated by the strong agreement between determined and experimental data, with contact temperature averages deviating by no more than 12%. In order to improve hard rock drilling performance, [5] evaluated rotary drilling hammers and tri-cone roller cone drill bits to increase penetration rates in hard rock formations. Determining the penetration rates required careful consideration of the Brazilian tensile strength, elastic modulus, triaxial compressive strength, and uniaxial compressive strength. Heat fluid and temperature on the surface of rock samples were assessed using the thermal spallation method [6], and the findings were compared between granite and sandstone samples. The two samples' temperature variations and penetration

rates were contrasted. For sensitivity analysis in drilling and cutting operations, a thermal sensor was developed by [7] It maps the temperature distribution at cutting tools. In the laboratory, [8] measured the temperature during drag-pick cutting of hard (granite) and soft (limestone) rocks and found that frictional heat was responsible for the higher temperatures. Wear rates increased at temperatures over a critical threshold (500°C) [9].

For ultra-deep well drilling, there are three main technical issues with drilling fluid: stability of additives against high temperature (aging), control of rheology and filtration loss with high solids content and a narrow safe density window and poor stratum pressure-bearing capacity that result in stick slip of a drill bit, drilling fluid leakage, and borehole collapse. As the water base mud's temperature rises bentonite will get hydrated and passivated, which will have a significant impact on the clay's properties. Thus, clay hydration in the highest temperature drilling mud is the primary issue [10].

Drilling mud's primary purpose is to transport drill cuttings to the surface during drilling. Drilling fluid also supports the hole walls, cools the bit, powers the mud motor and measuring-while-drilling (MWD) tool, and regulates well pressure (stops the well from flowing). Reverse circulation is an alternate technique in which the fluid flow is inverted from the one described before [1]. The mud system must be experimentally examined at both the standard API and the high temperature, high pressure settings at regular intervals during the drilling operation in order to determine the mud properties [11]. Determining the characteristics of mud under surface conditions is rather simple. Furthermore, it is challenging and dangerous to maintain bottom-hole conditions at the surface for experimental purposes. The idea of aging is utilized to examine a drilling fluid's characteristics at bottom-hole circumstances based on surface conditions. Drilling fluid aging is the process by which a sample of drilling fluid that has been sheared in the past is given more time to fully develop its filtration and rheological qualities. When mud is left inert, like when tripping, aging occurs. Conditions for aging range from ambient to intensively examined, and from static to dynamic [12].

1.3 Problem Statement

Drilling fluids are subjected to harsh temperature and pressure conditions throughout contemporary drilling operations, particularly in deep and high-pressure wells. The mud's filtration and rheological characteristics are drastically changed by these circumstances. Although drilling fluid technology has advanced, little is known about how temperature and pressure, both separately and together impact the filtration behavior of drilling mud. High temperatures can decrease viscosity, increase filtrate loss, and break down chemical additives and polymers. In a similar vein, high pressures can disrupt filtration dynamics, compress the filter cake, and modify permeability.

Excessive fluid invasion the creation of a thick filter cake, formation damage, and higher operating expenses can all be caused by improper regulation of these parameters. Therefore, in order to enhance fluid design and guarantee safe and effective drilling operations, a methodical examination of how temperature and pressure affect drilling mud filtration qualities is required.

1.4 Aim of the Study

This study's primary goal is to look at how drilling mud filtration qualities are affected by temperature and pressure. Among the particular goals are:

- To assess how temperature changes affect the thickness of the filter cake and the volume of filtrate.
- To examine how variations in pressure affect cake compressibility and filtration rate.
- To investigate how drilling mud performance is affected by both temperature and pressure.
- To contrast the outcomes of experiments conducted under HTHP and API standard conditions.
- To offer suggestions for enhancing the design of drilling fluids in wells with high temperatures and pressures.

1.5 Scope of the Study

The laboratory examination of drilling mud filtration characteristics under various pressure and temperature circumstances is the main emphasis of this work. The study comprises:

- Standard API filtration tests are used to test drilling fluid samples.
- Carrying out research with High-Temperature High-Pressure (HTHP) filtration .
- Determining the permeability, filter cake thickness, and filtrate volume. Examining the connection between filtration behavior, pressure, and temperature.

The study is restricted to controlled laboratory settings and water-based drilling mud systems. Complex geological formations and long-term chemical deterioration are examples of field-scale operational variables that are outside the purview of this study.

1.6 Significance of the Study

For the oil and gas sector, it is crucial to comprehend how temperature and pressure affect the filtration characteristics of drilling mud. In the pursuit of deeper and more intricate reservoirs, drilling fluids need to function well in harsh environments. The study's conclusions will:

- Assist in improving drilling fluid compositions for HTHP wells.
- Lower the chance of differential sticking and formation damage. Boost drilling efficiency and wellbore stability.
- Minimize fluid loss and operational issues to help cut expenses.
- Give scientific information for upcoming drilling fluid technology research.

This research contributes to safer and more cost-effective drilling operations by advancing our understanding of filtering behavior under harsh conditions.

1.7 Organization of the Report

There are multiple chapters in this report:

The study's history, problem description, aims, scope, significance, and general structure are all presented in Chapter One.

The literature on drilling fluids, filtration mechanisms, filter cake qualities, and the effects of pressure and temperature on filtration properties is reviewed in Chapter 2,3,4.

The study's materials, experimental techniques, and methods. The experimental results and findings are presented and discussed in Chapter 2,3,4.

Chapter two

2.1 Introduction

Investigated the effect of temperature gradient on rock failure both theoretically and empirically . With an average increase in penetration rate of 22.4% as the temperature differential increased, their results demonstrated that temperature gradients considerably facilitated rock collapse during drilling. increased in proportion to sandstone from 30°C to 180°C. A predictive model was created in order to assess the temperature distribution of wells dug for geothermal energy and shale gas [13]. Increased drill displacement and longer fluid circulation durations were linked to lowering the upper wellbore. As the viscosity increased, the drilling fluid's temperature inside the drilling string decreased. A drilling temperature model was developed by [13], with the goal of strengthening wellbores for oil and gas well testing. Wells with shallow drilling angles will especially benefit from this model's ability to reduce lost circulation accidents, related well downtime, and drilling costs. Through numerical simulations, the performance difference in rock breaking between a new drilling instrument and old ones was examined [14]. The novel drilling apparatus's creative design has the ability to improve process quality and core drilling efficiency. For future studies that attempt to improve drilling efficiency and rate of penetration (ROP), especially in complex and large displacement wells, the model provides useful information [15]. devised a five-point incendivity classification for rocks, and the results were connected with relevant chemical properties, mineralogy, and petrographic structure. The point of contact or the heat trail connected to it, rather than the incandescent particles generated during the frictional process, caused a temperature increase of 1500°C in less than a second during rock-on-rock collisions. A model that forecasts variations in rock and fluid temperatures during fluid circulation in wellbores was presented by [21].dimensionless characteristics were found via dimensional analysis, and downhole temperature was found to be highly influenced by injection rate. The rock close to the wellbore may undergo thermo-mechanical changes as a result of the cooling fluid returning via the annulus, which could start hydraulic fracturing [16]. Developed thorough models to clarify the

distribution of temperature during drilling, demonstrating notable temperature interactions between the drill collar and drill pipe . There was little change in the drilled section's temperature distribution [17]. Created an integrated heat transport model that incorporated. Hollow balls and rock are being fractured by drill bits. Improved heat transfer between the annulus and formations led to a slow rise in bottom hole temperature over time in dynamic drilling scenarios. An innovative temperature measuring device for deep lunar drilling was presented by [18]. At depths of up to two meters, this device allowed temperature readings (using thermocouples and platinum resistors) at many locations within the lunar vacuum environment, such as the revolving drill bit and lunar simulant. At these sites, the device demonstrated excellent performance in precisely measuring temperature. The majority of the calcite in downhole testing disintegrated within the combustion front, especially between 550°C and 650°C, according to (Zhao et al) [19].

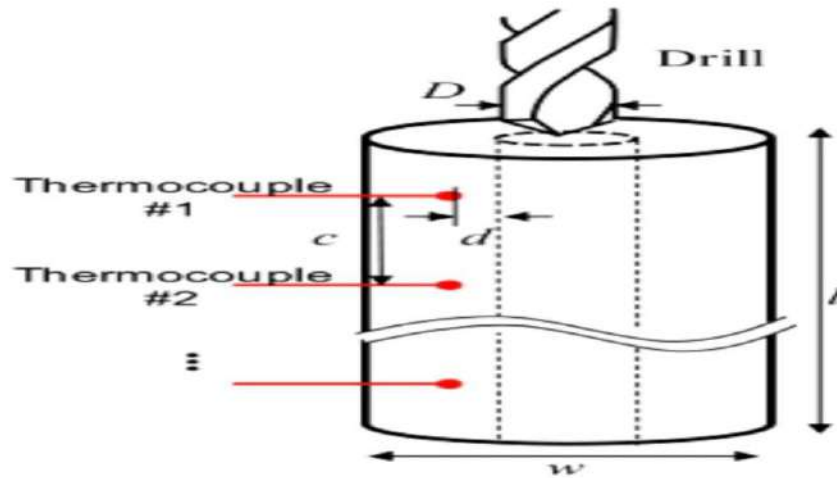


Figure 2.1: Temperature at the interface utilizing the inverse heat transfer technique [71]

According to the pyrolysis process, the maximum temperature differential at the central surface continuously increases as the sample diameter increases [20]. The temperature dynamics and their affecting elements during drilling have become significant problems in space engineering, especially in vacuum environments [21]. Micro bit drilling tests were carried out on sandstone in lab conditions to determine the effects of temperature and pressure. The combined effects are given precedence over individual influences by engineers [22]. To examine how the drilling area radius of the surrounding

rock affects the procedure, a prediction model was built. The predictive model's ability to accurately estimate the geothermal gradient was demonstrated by the final temperature difference between measured and model-derived values, which was less than 10% [23]. Applications for drilling operations are numerous in the mining, petroleum, and manufacturing sectors. Predicting temperature variations in rock samples or drill bits is difficult due to the heat produced during drilling. One important element influencing the physics-mechanical characteristics of rocks is temperature. Temperatures of several hundred degrees Celsius can be reached by the drill bit and rock samples during drilling. To predict this temperature, a variety of techniques are used, selected according to particular needs and applications. As a result, there is a need for a tool and technique specifically designed to measure temperatures during rock drilling. With some modest modifications, methods used for measuring temperature in metal machining have been modified for rock cutting. Temperature-measuring devices called thermocouples are used in rock drilling in accordance with certain goals and requirements [24].

2.2 Drilling Fluid and Their Functions

Controlling the fluid's flow properties is essential to processing drilling fluid correctly. This is referred to as the fluid's rheology. With the exception of air and clear water, the majority of drilling fluids are non-Newtonian. This indicates that the shear rate affects the viscosity. Water, salt water, or cement are examples of Newtonian fluids that have the same viscosity regardless of flow rate or shear rate [25].

The most crucial component of the drilling industry for a dependable and safe drilling operation is drilling fluid. Drilling fluid exchanges heat with the formation surrounding the wellbore throughout the drilling operation by traveling below via the drilling string and emerging to the surface through the annulus. Since temperature influences the rheological characteristics of drilling fluid, cement slurry design, cement thickening time, cement compressive strength, pumping time, and changes in fluid density, understanding the temperature profile and how it varies throughout the well depth is a crucial parameter. Inaccurate bottom-hole pressure estimation results from any disparity in density estimation. It is frequently believed that the characteristics of the drilling fluid remain unchanged throughout the drilling process. Particularly in high pressure-high temperature (HPHT) wells, this assumption is wildly incorrect. The estimation of bottom-hole pressure and circulating fluid temperature has been the subject of numerous studies over the years [26].

Originally thought of as a way to raise rock cuttings to the surface, drilling fluids are now acknowledged as one of the primary causes of any drilling operation's success or failure. In addition to lifting cuttings out of the wellbore, it carries out other crucial tasks that are necessary for a drilling operation to be completed safely, effectively, and economically. Transporting drill cuttings to the surface, suspending drill cuttings when circulation is suspended, lubricating and cooling the drill bit, controlling subsurface pressure, supporting the drilled hole's walls, and sealing permeable formation are some of the main purposes of drilling mud for a rotary drilling process. Because of the high temperature and high pressure in the reservoir, one of the biggest issues in drilling deep wells is that the drilling fluid must to have

exceptional thermal stability for rheological characteristics. As a result, as drilling depth grows, the wellbore temperature rises as well, which affects drilling mud characteristics including density viscosity, yield point (YP), and plastic viscosity (PV). Rheology is the study of how all matter deforms and flows. Viscosity, gel strength, and other rheological measurements of fluids are used to predict how the fluid would behave under certain circumstances. When designing the circulation systems needed to achieve specific desired goals in drilling operations, this information is crucial. The drilling fluid must reach the required viscosity, density, and other rheological characteristics in order to perform the majority of the aforementioned tasks. The rheological qualities of the drilling fluid to be utilized are always given a lot of weight in today's drilling operations. This is due to the fact that drilling fluid performance is significantly impacted by these characteristics in terms of penetration rate, static and dynamic carrying capacity, and hole cleaning. Drilling issues may result from poor rheological modifications or inadequate drilling fluid design. The mud system must be experimentally examined at both the conventional API and the high temperature, high pressure settings at regular intervals during the drilling procedure in order to determine the mud parameters. In order to improve the drilling mud's rheological qualities and enable it to carry out its intended tasks without any issues, numerous chemicals are added when experiments reveal a change in the mud's characteristics [27].

DRILLING FLUID FUNCTIONS:

According to Nasser et al., the fluid characteristics must be consistently maintained during the drilling operation in order to save fluid costs and guarantee an effective drilling program. Furthermore, the high temperatures and high pressures encountered in ultra-deep oil and gas drilling environments present significant difficulties for the fluids used in these settings, which lower drilling efficiency by slowing penetration rates and causing serious issues that ultimately result in the majority of the oil being left unrecovered. Among the many features that a chosen drilling fluid must provide are:

- regulate subsurface pressures while keeping the well under control;
- Extract drilling debris from behind the bit and move it to the top;
- Preserve the mechanical and chemical stability of the wellbore:
- Let the drill bit and string cool and lubricate;
- Permit a sufficient assessment of formation:
- Provide a wellbore that has been finished and will yield hydrocarbons;
- Allow drill cuttings to be removed from the surface fluids processing system while suspending or reducing the settling of drill cuttings or weight material when circulation is stopped; and
- Create a thin, durable filter cake with low permeability throughout the permeable structure. The kind of formation being drilled and the different characteristics of the drilling fluids affect how well these functions work [28].



Fig 2.2: Drilling Fluids [72]

2.3 Filtration Mechanism of Drilling Fluids

Drilling fluid infiltrates the formation (spurt loss) when its hydrostatic pressure exceeds the pore pressure. Particles of the right size, typically one-sixth to one-third the size of pore throats at the well bore, quickly bridge the pores and start to form a filter cake, despite the suspended solids' best efforts to flow in with the liquid fraction. The gaps created by the bridging particles are gradually filled with ever-finer particles, creating a web so tightly packed that only liquid (filtrate) may pass through. Following the establishment of this filter cake, the permeability of the cake determines the fluid flow rate into the formation. Filter cake develops undisturbed (static fluid loss) when mud is not circulated, and the rate of filtration after the cake is built is proportional to the square root of time. The filter cake expands as the mud circulates until the shear stress the mud exerts equalizes the filter cake's shear strength (dynamic fluid loss). The cake has a limiting thickness in this situation, and the rate of filtration after the cake is formed is proportional to time. In dynamic settings, spurt loss is frequently higher. The particles that entered the formation during the spurt-loss phase, whether static or dynamic, may or may not eventually aid in the creation of an internal filter cake [29]. Darcy law governs filtration of liquids through porous media. However, fluid loss from the wellbore will decrease with time, since the permeability decreases continuously as particles make a tighter filter. In Figure 2.3, the spurt loss occurs at the start of a filter test, a test which is made on an initially clean filter paper. After the spurt loss, the filtrate volume becomes proportional to the square root of time.

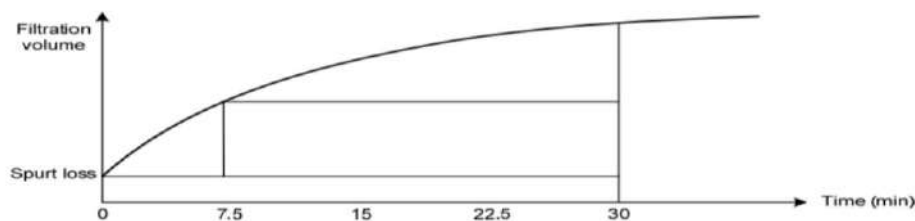


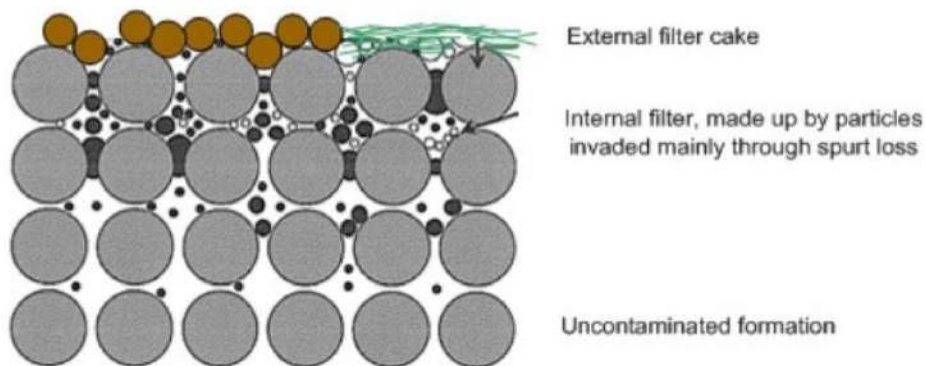
Figure 2.3: Filter press test results.[30]

It is common to simplify laboratory procedures by decreasing test duration to 1/4 of the standard 30 minutes. The accumulated filtrate volume can be predicted from equation,

$$q_{(f)} = q_{(s)} + C * \sqrt{t} \quad \text{eq(1)}$$

For example, the 30 minute filtrate volume is predicted by measuring the filtrate volume at 7.5 minutes, and doubling the value obtained, since $\sqrt{30}/\sqrt{7.5} = 2$

Drilling into extremely permeable rocks can result in significant fluid loss in the well unless the mud has particles large enough to bridge the rock's pores and create an improved filter a little before the bit. Bridges can only be formed by particles that are a specific size in relation to the pore size. The mud stream carries away particles that are too big to fit through the pores. Unhindered, particles far smaller than the entrance enter the structure. A bridge forms inside the porous wall when particles of a specific critical size become trapped in flow channel bottlenecks. Once a primary bridge is established, successively smaller particles, down to the fine colloids, are trapped, and thereafter only the filtrate (liquid) may invade the formation. The spurt loss period is very brief, it is a matter of seconds [30]. As a result of the process just described, three zones of mud particles are established in a permeable formation. This is shown in Figure 2.4



1. Figure 2.4: Invasion of a permeable formation by particles in the mud.[30]

Emulsified water droplets in water-based mud (right) or oil-based mud (left) can be used to create the outer filter cake. It's crucial to provide the mud a particle size distribution that matches the pore size distribution of the porous formation that needs to be drilled through in order to create a tighter filter. The ideal particle size is between 1/3 and 1/7 of the average pore throat size. Table 2's drilled particles and barite will always be accessible and ideal for filter construction. Nevertheless, these particles will also obstruct the process of filter cake formation.

2. Table 1: Drilled solids classified by particle size. (PAL SKALLE, DRILLING FLUID ENGINEERING, 98-100.)

1. Coarse	Particles greater than 2 000 microns
2. Intermediate	Particles between 250-2 000microns
3. Mediums	Particles between 74-250 microns
4. Fines	Particles between 44-74 microns
5. Ultrafine	Particles between 2-44 microns
6. Colloidal	Particles less than 2 microns

The ideal mud state for creating a filter cake is a dispersed mud. A thick, soft filter cake will result from substantial water loss in flocculated bentonite. A thin, robust, and low-permeable cake will form when a thinning chemical (deflocculated or thinner) is added. Generally speaking, the filter cakes of muds treated with dispersants have permeabilities of around 10 md, flocculated muds have permeabilities of around 10 md, and untreated freshwater muds have permeabilities of around 10 Md [31].

The industry standard static filtration test is the API Fluid Loss Test (30 minutes, AP100 psi through No. 50 Whatman filter paper, ambient temperature). However, because the filter medium is extremely fine mesh paper, all bridging particles are stopped at the paper's surface, and the spurt-loss phase is not accurately simulated. This typically results in glaring underestimations of the surge loss. A 1/4-inch-thick ceramic disk with known permeability is used in the PPT, or permeability plugging test, which is a

better static filtration test [API 13B1/API 13B2]. A core composed of the same ceramic material is used in dynamic filtration, like in the Fann 90 test, to mimic the fluid in the annulus shearing the filter cake. Cake thickness depends on the filtration rate, the concentration of solids, PSD, and the amount of water retained in the cake at a particular pressure and temperature. As the solids content rises, the filtration rate falls while the cake thickness rises. Conversely, permeability remains constant. Nearly all permeability depends on the size and characteristics of the colloidal fraction (less than 2 μm in diameter). Particle size and shape have a significant impact on permeability, which decreases as the fraction of colloids increases. To achieve low permeability, a wide range of particle sizes is necessary. Unlike spherical, granular, or needle-shaped particles, flat particles (like bentonite) can pack extremely tightly. However, some organic macromolecules, like hydrolyzed starch, are quite malleable and seem to blend in well with the spaces between most filter cakes. Similarly, polyelectrolytes that are big enough to get trapped in the pores of filter cakes include PAC (polyanionic cellulose) and CMC (carboxymethyl cellulose). In NAFs, organophilic clays, water, and surfactants are used to colloidally regulate the permeability of the filter cake [32].

Particles unite during flocculation to create a loose, open network. When a drilling fluid is flocculated (for example, by adding salts), some of the flocculated character is present in the filter cake that is produced at the well bore, and the rate of filtering rises. The permeability of cakes is reduced by thinners (deflocculants) such as lignosulfonates, which disperse clay flocs. The presence of a significant concentration of bridging particles with a broad PSD in the mud is just as crucial as the presence of a sizable colloidal fraction of solids with a broad PSD. The maximum size of bridging particles is also crucial. Particles that are between one-sixth and one-third the size of the largest "pore throat" in a drilling interval are adequate, but they must remain significantly concentrated in the fluid during the interval. The necessary maximum bridging particle size can be roughly estimated using the following [Glenn & Slusser]:

Table 2: Permeability (mD) and Maximum Particle Size (μm)

Permeability (mD)	Maximum Particle Size (μm)
<100	2
100-1,000	10
1,000-10,000	74 (200 mesh)

A drilling fluid containing particles of sizes ranging up to the requisite maximum should be able to effectively bridge the formation and form filter cake. Above 10 mD or in fractures, larger particles are required, and most likely the amounts needed to minimize spurt loss will also increase with the size of the opening. Generally, with increasing concentration of bridging particles, bridging occurs faster and spurt loss declines. For consolidated rock with permeability in the range 100 to 1000 mD, only 1 lb/bbl of 10-mm particles is necessary to prevent mud spurt from invading farther than 1 inch into the rock. On unconsolidated sands of that same permeability, 5 to 30 times that amount may be required. Reservoir drilling fluids typically contain as much as 30 lb/bbl total of acid-soluble bridging materials (usually CaCO_3), sized to provide a broad size distribution for all solids in the fluid. Most drilling fluids typically contain enough particles of the necessary size range for non reservoir applications after only a few feet of rock have been cut. When drilling unconsolidated sands, however frequent use of desanders and desalters may deplete these particles, necessitating the addition of some bridging material. Similarly, bridging particles must be introduced to the fluid in situations where drilling is not required, such as production repair work [33].

When the pressure in a well bore is higher than the formation pore pressure, fluid will tend to enter the formation in the permeable zones. The solids in the drilling fluid will be deposited on the wall of the well bore. These solids are called a filter cake. In a well, filter cakes should be thin, slick, and compressible. The filter cake should be extended regularly to examine the filter cake that could be deposited on the wall of the well bore.

The room temperature water loss is measured by applying 100 psi to a fluid above a Whatman No. 50 filter paper which is supported by an API 200

screen. The amount of fluid collected in 30 min, the filter cake thickness, and a description of the filter cake are to be reported. This is called the API water loss test (APIWE). The high temperature fluid loss is measured by applying a 100 psi differential across a Whatman No. 50 filter paper supported by an API 200 screen as well. The temperature is not specified in the API 138 documents. Generally, either a temperature about 50 °F higher than the bottom hole temperature or 300 °F is used. A back pressure is applied so that the liquid will not boil and vaporize. The API RP 13B-1 and 1311-2 give produced uses for using temperatures to 300 °F but does not indicate what temperature should be used. (Since the 300 °F temperature is prominently mentioned, many think it is specified as the correct value for the test-it is not.) Filter cake compressibility can be determined by comparing the 100 psi fluid loss measurement with a 500 psi pressure fluid loss from the high temperature cell but make both measurements at room temperature [34].

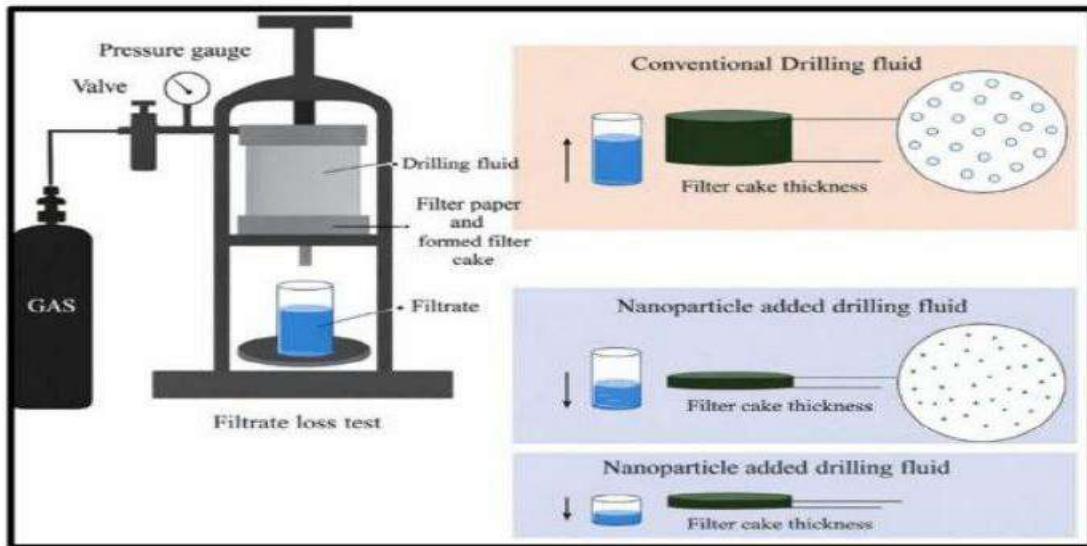


Fig 2.5: Filtration Mechanism of Drilling Fluid (73)

2.4 Filter Cake Characteristics

The mesh filter, a crucial part of drip irrigation systems, often faces a significant clogging problem after extended use, which significantly impairs the systems' ability to function smoothly. Thorough research on the clogging mechanism and cake structure of the mesh filters is essential to the development of water-saving drip irrigation. Research on filters, both domestically and internationally, has concentrated on clogging reasons and filtration performance. The impact of structural optimization on the flow field, as well as the effects of flow rate, concentration, filter structure, and other factors on filtration efficiency, have been the main subjects of extensive research on filtration performance.

There were few and out-of-date research on mesh filter clogging. Wen thought that filter cake fouling could increase head loss and improve filter performance. Furthermore, the degree of filter cake clogging was described using the filter's two properties, permeability and porosity. In their analysis of the reasons of filter clogging, Discovered that the sand content and screen aperture size were significant factors influencing clogging. Based on the experimental findings, a quantitative relationship equation for the pressure drop inside and outside the screen was developed [35].

Additionally, it was discovered that clogging happens more quickly the smaller the filter mesh's aperture and the more sand there is in the mixture. Studies on the structure of filter cakes in other domains are also useful for reference in comprehending mesh filters, even though there aren't many on the structure of filter cakes in mesh filter clogging. [36] built a three-dimensional digital filter cake and used CT scanning imaging and pressured filtration experiments to derive the aperture network model. Finally, they developed a model of the link between permeability and pores. performed vacuum filtration and dewatering of fine-grained coal under a variety of circumstances [37].

carried out dewatering and vacuum filtering on fine-grained coal in a variety of settings. To determine the filter cake's porosity and fractal size, they examined the aperture structure of the final product. The clogging process of

the geotextile was separated into three steps [38]. aperture clogging and filter cake creation, the dynamic growth of the filter cake, and filtering of the filter cake layer through microscopic analysis. The dynamic process of filter cake growth is known as filter clogging [39]. In order to understand the filter clogging status and improve the efficiency of filter operation, it is crucial to investigate the growth process of the filter cake. However, the final clogging of the filter cake has been the primary focus of current research on the clogging mechanism of mesh filters. Analyzing the impact of different parameters on filter cake development and structure from the standpoint of filter cake growth has not been the subject of many studies. Combining the results of earlier research, it was determined that the primary variables influencing filter clogging in real irrigation work were flow rate, sand concentration, and screen aperture size. Filtration of cakes is crucial in numerous procedures. Nevertheless, heuristics and experimentation continue to play a major role in the study and design of filtration operations. Constant rate filtration (CRF) is a well-established and often used technique in industry to recover either the filtrate or the solids [40].

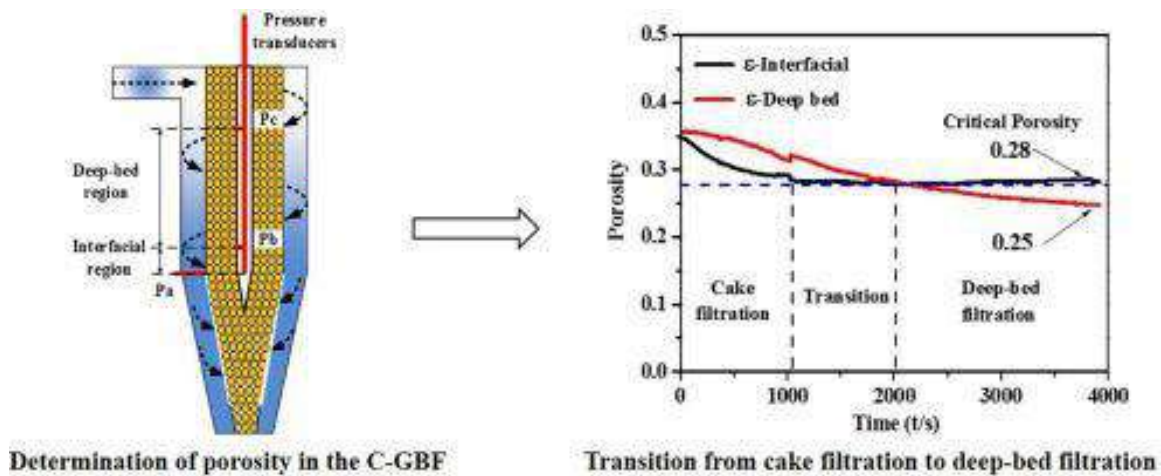


Fig 2.6: Filter Cake Characteristics (74)

2.5 Influence of Temperature on filtration

One of the key factors influencing the filtration properties of drilling fluids is temperature. The drilling fluid is subjected to high temperatures during drilling operations, particularly in deep wells, which can drastically change its chemical and physical characteristics. These modifications affect the drilling fluid system's overall stability, the thickness and quality of the filter cake, and the rate of filtrate loss. Therefore, creating drilling fluids that can function well in high-temperature environments requires an understanding of how temperature affects filtration. The growth in filtrate volume with temperature is one of the main ways that temperature affects filtering. The drilling fluid's viscosity drops at higher temperatures, making it easier for the fluid to pass through the filter medium and the porous formation. Consequently, more filtrate enters the formation and the rate of fluid loss rises. Raising the temperature causes a considerable rise in fluid loss, according to experimental investigations. In one study, for instance, the filtration volume rose from 2.9 ml at 194°F to 4.9 ml at 302°F and 7.3 ml at 392°F. This suggests that drilling fluids are less effective in controlling filtrate invasion into the formation at higher temperatures [41].

The formation and structure of the filter cake are also influenced by temperature. Solid drilling fluid particles accumulate on the wellbore wall during filtering, forming a filter cake that prevents more fluid invasion. However, this filter cake's properties might alter as the temperature rises. Higher temperatures frequently result in a thicker filter cake due to increased filtrate flow and solid deposition, according to research. The filter cake thickness in one experiment grew from 1.4 mm at 194°F to 1.9 mm at 302°F and 2.1 mm at 392°F, indicating that temperature has a major impact on the structure of the deposited solids layer [42].

The thermal deterioration of drilling fluid additives is another significant effect of temperature. High temperatures can affect a variety of additives, including polymers, viscosifiers, and fluid-loss control agents. These additives may deteriorate or lose their efficacy when exposed to high temperatures over prolonged periods of time. This deterioration results in weaker gel structure and decreased viscosity, which raises filtering rates and

reduces the drilling fluid's capacity to keep a stable filter cake. Because of this, specialist additives that are both thermally stable and able to maintain filtration control may be needed for drilling fluids operating at high temperatures.

An increase in temperature will usually result in an increase in filtration rate because of adverse temperature effects on filtration control agents and decreased fluid phase viscosity. Higher temperature may also increase the solubility of contaminants and, therefore, decrease the effectiveness of filtrate loss control chemicals. In addition, the colloidal fraction tends to flocculate and increase filtration at elevated temperatures. Deflocculation of the colloidal fraction can contribute significantly to filtration rate. In a flocculated system, colloidal solids cluster or aggregate, this increases cake porosity and permeability and allows more fluid to pass through the filter cake. Conversely, dispersion of colloidal solids results in a more uniform distribution of solids in the filter cake which reduces cake permeability and lowers filtration rates. Deflocculants such as UNI-CAL" are beneficial as supplementary filtration control agents. particularly at elevated temperatures that are encountered with depth. The theoretical change in filtrate, due to reduction of the viscosity of the filtrate as temperature is increased, Can be expressed by the following equation:

$$f(1) = f * \left(\frac{\sqrt{\mu}}{\sqrt{\mu_1}} \right) \quad \text{eq(2)}$$

where,

f = filtrate at a known temperature

f(1) = filtrate at an elevated temperature

μ = viscosity of water at known temperature

μ_1 = viscosity of water at an elevated temperature

The change in viscosity for water at various temperatures is noted in Table

Table 3: Viscosity of Water vs. Temperature

Temperature		Viscosity of Water (Centipoise)	Temperature		Viscosity of Water (Centipoise)
°C	°F		°C	°F	
0	32	1.792	40	104	0.656
10	50	1.308	60	140	0.469
20	68	1.005	80	176	0.356
30	86	0.801	100	212	0.284

(Data from Rogers, W. F.; *Composition and Properties of Oil Well Drilling Fluids*, Third Edition)

For example, a fluid has a known filtrate of 6.0 mL at 86°F and 100 psi. It is desired to predict the resultant filtrate at 140°F with pressure constant.

$$f(1) = f * \left(\frac{\sqrt{\mu}}{\sqrt{\mu(1)}} \right) = 6 * \left(\frac{\sqrt{0.801}}{\sqrt{0.469}} \right) = 6 * 0.895/685 = 7.8$$

Temperature changes of water-base fluid in the 80 deg to 140°F range will result in change of filtrate of approximately 10% for each 17°F change. Filtrate increases as temperature increases.

Increased temperature usually increases filtration rates by reducing the viscosity of the liquid phase, providing all other factors remain constant.

Figure 2.7 is a graph used to convert API fluid loss taken at any mud temperature to the theoretical API fluid loss value at 300°F if the pressure for both tests is the same. For example, if fluid loss at 140°F is 3c * m³ then multiplying by the constant 1.6 gives the theoretical value 4.8c * m³

300 °F

The effect on fluid loss due to temperature changes can be approximated by the following equation. Use Table 4 to obtain the viscosity of water at various temperatures.

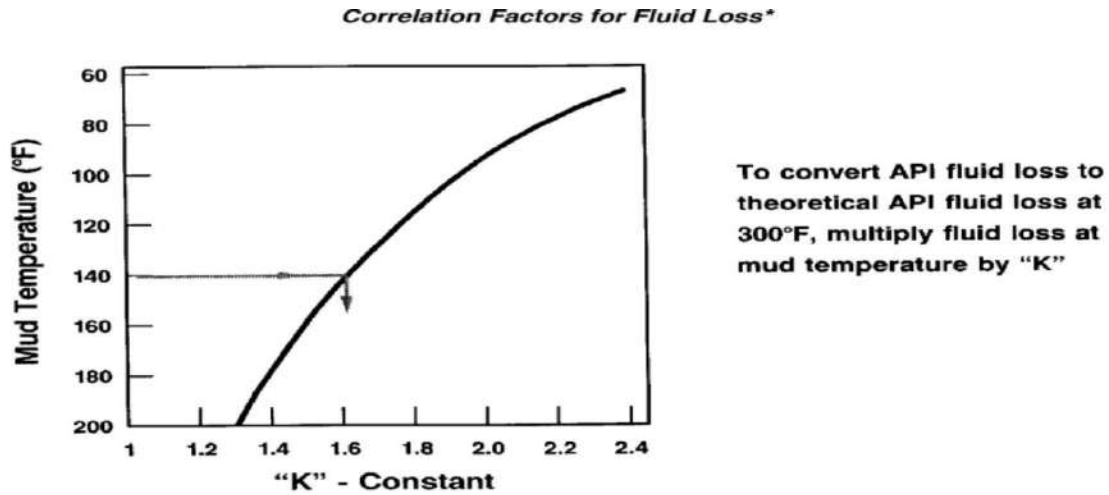


Figure 2.7: Correlation factors for fluid loss

Where

$$V_2 = V_1 * \frac{\sqrt{\mu_2}}{\mu_1} \quad \text{eq(3)}$$

V_1 = measured filtrate volume at test temperature

V_2 = calculated filtrate volume at temperature 2

μ_1 = water viscosity at test temperature

μ_2 = water viscosity at temperature 2

This equation can be used to estimate a fluid loss value for a higher temperature. If the actual fluid loss at the higher temperature is much greater than the calculated value, it can indicate thermal degradation of mud chemicals. High temperatures produce chemical changes in the mud. In particular, changes take place in the ionic atmosphere of clay particles and the effectiveness of many fluid-loss additives and dispersants decreases at high temperatures because of degradation [43].

Table 4: Viscosity of water at various temperatures.

<i>Viscosity of Water at Various Temperatures</i>					
Temperature		Viscosity of Water (cps)	Temperature		Viscosity of Water (cps)
°F	°C		°F	°C	
68	20	1.005	300	148.9	0.184
86	30	0.801	320	160	0.174
104	40	0.656	338	170	0.160
122	50	0.549	350	176.6	0.1535
140	60	0.469	356	180	0.150
158	70	0.406	374	190	0.142
176	80	0.356	392	200	0.134
194	90	0.316	410	210	0.127
212	100	0.284	428	220	0.121
230	110	0.256	446	230	0.116
248	120	0.232	450	232.2	0.1136
250	121	0.2316	500	260	0.100
266	130	0.212	550	287.7	0.0899
284	140	0.916	572	300	0.086

2.6 Influence of Pressure on filtration

One of the most important variables influencing how drilling fluids filter is pressure. Hydrostatic pressure, formation pressure, and applied differential pressure across the filter media all result in various pressure situations for the drilling fluid during drilling operations. The rate at which the drilling fluid's liquid phase moves through the porous formation or filter medium is significantly impacted by these pressure variations. Therefore, managing fluid loss, safeguarding the formation, and preserving wellbore stability all depend on an understanding of how pressure affects filtration. Differential pressure, which is the difference between the pressure of the formation and the drilling fluid in the wellbore, is one of the main ways that pressure influences filtration. When this pressure differential pushes the drilling fluid's liquid phase into the formation while solid particles build up on the wellbore wall and create a filter cake, filtration takes place. Higher filtration rates and more fluid loss result from the driving force forcing the filtrate into the formation increasing along with the differential pressure. According to experimental

research, filtration volume often rises as pressure increases because the liquid phase is pushed more forcefully through the porous material [44].

The creation and structure of filter cakes are two further significant effects of pressure. Solid drilling fluid particles accumulate on the formation's surface throughout the filtration process and progressively form a filter cake. Because the liquid phase is forced through the filter medium more quickly under higher pressure, these particles deposit more quickly. The filter cake may consequently get thicker and more compact. By serving as a barrier that restricts the flow of the liquid phase into the formation, a compact filter cake can lower the rate of further fluid loss. But if the pressure is too high, the filter cake can get too thick, which could cause drilling issues like pipe sticking or more torque and drag [45]. The filter cake's permeability is also impacted by pressure. The solid particles in the filter cake are squeezed more firmly together when higher pressure is used during filtration. By reducing the pore spaces between the particles, this compression lowers the filter cake's permeability and limits the filtrate's flow. Because of this, the production of a dense and compressed filter cake may eventually slow down the filtration process, even though higher pressure initially boosts the filtration rate. This pattern is frequently seen in filtration experiments where the filtration rate is high at first but progressively drops as the filter cake grows and compacts [46].

If the filter cake did not compress under pressure, the fluid loss would vary with the square root of the pressure. This does not normally apply to drilling fluids because the porosity and permeability of the filter cake is usually affected by pressure. A useful field check for determining cake compressibility is to measure HT/HP filtrate in the normal manner then test again with 100 psi differential pressure. The lower the compressibility ratio, [47]

$$CR = \frac{V_{low\ pressure}}{V_{high\ pressure}} \quad eq(4)$$

For example:

$$CR = \frac{V_{100\ psi}}{V_{500\ psi}}$$

The more compressible the filter cake becomes. If the compressibility ratio is 1.5 or greater, it could indicate that colloidal fraction is inadequate and that remedial measures are necessary. If the filtration medium is uniform, the volume of filtrate varies as the square root of pressure. This does not apply for mud filter cake however, because the cake, which is subject to compression and continued deposition of material, undergoes continuous changes in porosity and permeability. If the cake were incompressible and static, the effects of pressure is approximated by the equation :

Where

$$V_2 = V_1 \sqrt{\left(\frac{P_2}{P_1}\right)} \quad \text{eq(5)}$$

$P_1 = 100$ psi

$P_2 =$ pressure in question in psi

$V_1 =$ measured filtrate volume

$V_2 =$ estimated filtrate volume

This equation can be used to indicate the relative compressibility of an actual filter cake. Run an API fluid loss test at standard temperature and pressure and then run a second one at a higher pressure, for example at 200 psi. If the test results correspond closely to the results calculated by the above equation it indicates the formation of an incompressible filter cake. The lower the actual fluid loss at the higher pressure compared to the calculated fluid loss, the greater the compressibility of the cake [48]. It is possible in extreme cases to have a fluid loss at higher pressure which is lower in volume than the fluid loss at the lower pressure. This situation indicates an extremely compressible filter cake [49].

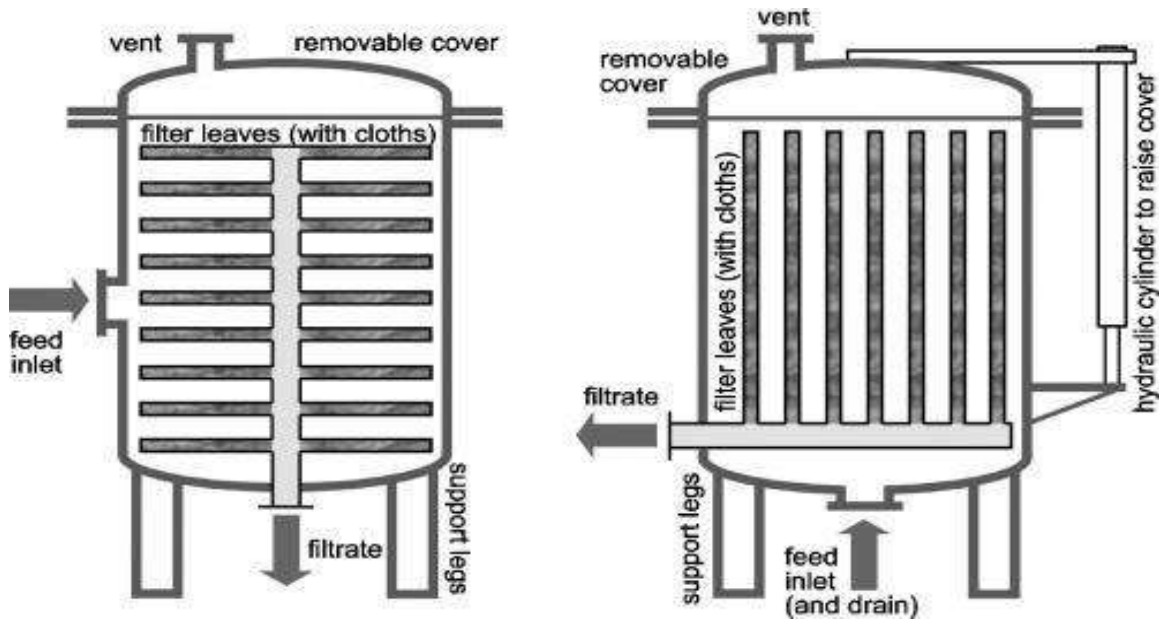


Fig 2.8: Influence of Pressure on filtration[75]

2.7 Combined Temperature-Pressure effects

Combined Effect of Pressure and Temperature on Yield Stress:

Figures 2.9 and 2.10 display the evolution of the Herschel-Bulkley yield stress with pressure, in the temperature range comprised between 40°C and 140°C, for B34 and B128-based drilling fluids, respectively. As can be seen, yield stress always linearly increases with pressure in the range of pressure tested. Consequently, the isothermal yield stress behaviour can be modelled by a simple equation, as follows:

$$\tau_c = \tau_{co} + \beta_\tau (P - P_o) \quad \text{eq(6)}$$

where τ_c is the Herschel-Bulkley yield stress, τ_{co} is the yield stress at the reference pressure for each temperature, β_τ is a isothermal piezo-yield stress coefficient, p is the applied pressure, and p_o is the pressure of reference (1 bar). The values of the piezo-yield stress coefficient in a temperature range comprised between 40°C and 140°C, for both oil drilling fluids, are shown in Table 5. As can be observed in these figures, the influence of pressure on the yield stress is more significant for B128-based drilling fluid, which also shows

the highest values of yield stress. Similar behaviour, in the low shear-rate region.

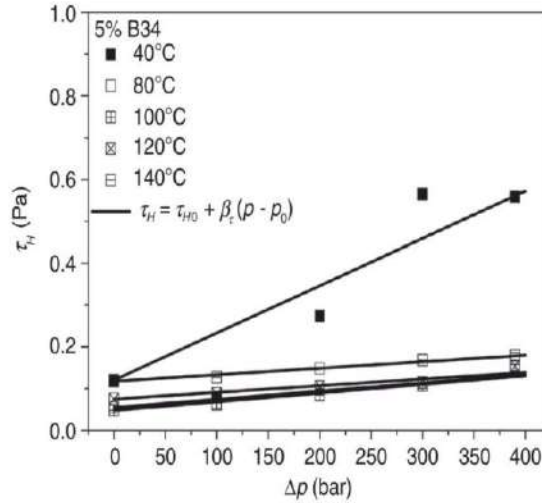


Fig 2.9: Effect of pressure on Herschel-Bulkley's yield stress for B34-based drilling fluid, as a function of temperature

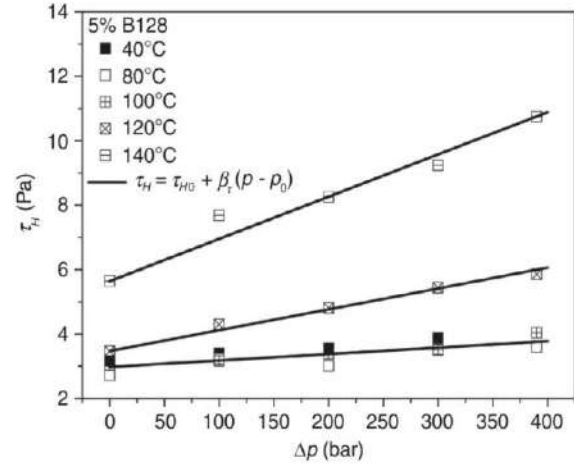


Fig 2.10: Effect of pressures on Herschel-Bulkley's yield stress for B128-based drilling fluid, as a function of temperature.

Changes in B34-based drilling fluid piezo-yield stress could be associated with the thermal weakening of inter-particle interactions in the agglomerates and reduction in the effective agglomerate concentration, being the yielding behaviour less sensitive to pressure changes as temperature increases, even enhancing its compressibility with temperature [50]. In addition, this decrease in yield stress with an increase in temperature may be related to a decrease in oil viscosity [51].

On the contrary, for B128-based drilling fluid, the pressure/temperature dependence of the yield stress is quite different. As can be seen in Figure 2.11, yield stress dependence on pressure is roughly independent of temperature below 120°C. In addition, the larger influence of pressure on this parameter could be related to the compression of a thermally-modified denser structure, as have been pointed out by Politte (1985) for inverted oil muds. From the engineering point of view, the temperature and pressure dependence of the yield stress is of major interest for the design of transport operations in the oil drilling industry [52]. In this sense, drilling fluids are mainly designed to be

able of suspending drill cuttings under static conditions. According to the results obtained in this study, the B34-based oil drilling fluid presents fairly low cutting carrying capacity, but also not excessive horse-power pump requirements in the range of pressure and temperature tested (see yield stress values in Tab. 5). On the contrary, B128 organoclay can be considered a potential candidate to prepare suspensions able to be used for drilling fluid applications, with yield stress values below 15 Pa , in the whole range of pressure and temperatures studied.

Table 5

Piezo-yield stress coefficients for the oil drilling fluids studied, at different temperatures

	B34		B128	
	$\beta_i (\times 10^4, \text{Pa/bar})$		$\beta_i (\times 10^4, \text{Pa/bar})$	
$T (^\circ\text{C})$	Bingham's model	Herschel-Bulkley's model	Bingham's model	Herschel-Bulkley's model
40	15.6	11.3	16.5	16.8
80	2.36	1.94	23.9	23.6
100	2.04	2.06	20.8	19.6
120	1.25	1.59	64.9	64.8
140	1.82	1.57	132	131

Filtration behavior in drilling operations is rarely determined by a single component. Rather, in deep wells and geothermal drilling environments, drilling fluids are often subjected to simultaneous high temperature and high pressure (HPHT) conditions. The filtration properties of drilling fluids, such as filtrate volume, filter cake formation, and the stability of drilling fluid additives, are greatly influenced by the combined effects of temperature and pressure. Therefore, forecasting drilling fluid performance under downhole conditions requires an understanding of the relationship between temperature and pressure. The increase in filtrate loss under HPHT circumstances is one of the most important combined impacts of temperature and pressure. The drilling fluid's viscosity tends to decrease with increasing temperature,

making it easier for the mud's liquid phase to flow. High differential pressure simultaneously pushes the fluid through the porous structure more forcefully. Together, these two elements significantly speed up the filtration process and increase the volume of filtrate that enters the formation. Drilling fluids frequently show much higher fluid loss values under combined temperature and pressure circumstances compared to ordinary surface settings, according to laboratory HPHT filtration studies [53].

The alteration of filter cake structure is another significant result of temperature and pressure working together. A filter cake that prevents fluid invasion is created when the solid particles in the drilling fluid are crushed against the formation surface under high pressure. However, the drilling fluid's rheological characteristics may alter in the presence of high temperatures, which could have an impact on the suspended particles' size distribution and behavior. As a result, depending on the nature of the drilling fluid, the filter cake may become thicker, denser, or occasionally more fragile. To efficiently limit filtrate loss in HPHT environments and avoid drilling difficulties such pipe sticking, the filter cake needs to stay thin and low-permeability [54]. The thermal stability of drilling fluid additives is also impacted by the combined effects of temperature and pressure. Many fluid-loss control additives, including viscosifiers and polymers, are susceptible to high temperatures and may deteriorate under extended HPHT conditions. The additives lose their capacity to maintain appropriate viscosity and filtration control when heat deterioration takes place. High pressure keeps pushing the liquid phase through the formation at the same time, greatly increasing fluid loss. Because of this, drilling fluids used in deep wells frequently contain thermally stable additives that may continue to function at HPHT conditions, such as modified polymers or nanoparticles [55].

2.8 Filtration Theory

Filtration refers to the process of passing a liquid through a porous, permeable media in order to remove any particulate matter suspended in the liquid. The filtering media can be paper, ceramic, fibrous, or packed beds of material such as diatomaceous earth, coal or sand. All of these media are used on occasion depending upon circumstances. In the oil field, we are particularly concerned with filtering clear brines used as workover and completion fluids. It has long been known that even small concentrations of fine particulates can cause formation damage in the form of permeability reduction by plugging formation pore throats. This damage is difficult if not impossible to reverse and economics indicate that prevention, by removing the fine particulate matter prior to contact with the formation, is always the less expensive choice [56].

Studies indicate that particles in the range of $1/3$ to 1 times the pore throat diameter pose the greatest threat of formation damage. The larger particles will tend to plug off the pore immediately while the smaller particles will tend to enter the pore throat and bridge off deeper into the formation. It appears that particles less than $1/3$ the pore throat diameter pose no serious threat to the formation. Based on this data a general recommendation for maximum particle size and concentration has been formulated. It is generally assumed that fluids containing particles less than 2 microns in diameter in concentrations of less than 100 mg/L are relatively safe for use as workover and completion fluids. The source of the particulate matter varies considerably. Sediment from the water source, particularly if it is from a lake or stream, algae and bacteria present in stagnant water or sea water, impurities in the solid salts used in formulating the brines are all common sources of contamination. In addition, sediment, rust, or remains of other fluids from the tanks used for transporting the brines, as well as similar contaminants from the tanks or pits at the rig site all add to the difficulty of maintaining a solids free liquid [57].

When the hydrostatic pressure of the drilling fluid is greater than the pore pressure, drilling fluid invades the formation (spurt loss). Suspended solids attempt to flow in with the liquid fraction, but very quickly particles of the

appropriate size (generally one-sixth to one-third the size of pore throats at the well bore) bridge the pores and begin to build a filter cake. In time, finer and finer particles fill the interstices left by the bridging particles and ultimately form such a tight web that only liquid (filtrate) is able to penetrate. Once this filter cake is established, the flow rate of fluid into the formation is dictated by the permeability of the cake. When mud is not being circulated, filter cake grows undisturbed (static fluid loss) and the rate of filtration after the cake is established is proportional to the square root of time. When the mud is being circulated, the filter cake grows to the point at which the shear stress exerted by the mud balances the shear strength of the filter cake (dynamic fluid loss). Under this condition, the cake has a limiting thickness and the rate of filtration after the cake is established is proportional to time. Often, spurt loss is greater under dynamic conditions. Whether static or dynamic, the particles that invaded the formation during the spurt-loss phase may or may not ultimately help to form an internal filter cake, too. The API Fluid Loss Test (30 min, AP100 psi through No. 50 Whatman filter paper, ambient temperature) is the standard static filtration test used in the industry; however, because it uses very fine mesh paper as the filter medium, all of the bridging particles are stopped at the surface of the paper and the spurt-loss phase is not simulated properly. Usually this leads to gross underestimates of the spurt loss. A better static filtration test is the PPT, or permeability plugging test, which uses a 1/4-inch-thick ceramic disk of known permeability [API 13B1/API 13B2]. Dynamic filtration, such as in the Fann 90 test, uses a core made of the same ceramic material and simulates shearing of the filter cake by the fluid in the annulus. For a given pressure and temperature, cake thickness is related to the filtration rate and is a function of the concentration of solids, PSD, and the amount of water retained in the cake. Filtration rate decreases with increasing concentration of solids, but cake thickness increases. Permeability, on the other hand, does not change. Permeability is almost entirely dependent on the proportion and properties of the colloidal fraction ($<2\text{ }\mu\text{m}$ diameter). Permeability decreases with increasing fraction of colloids and is affected strongly by particle size and shape. A broad distribution of particle sizes is important to attain low permeability. Particles that are flat (e.g., bentonite) can pack very tightly, in contrast to spherical, granular, or needle-shaped particles. On the other hand, some organic

macromolecules, such as hydrolyzed starch, are highly deformable and appear to fit well in the interstices of most filter cakes. Similarly, polyelectrolytes like CMC (carboxymethyl cellulose) and PAC (polyanionic cellulose) are large enough to be trapped in the pores of filter cakes. In NAFs, colloidal control of filter cake permeability is achieved with surfactants and water, as well as organophilic clays. Flocculation causes particles to join together to form a loose, open network. When a drilling fluid is flocculated (e.g., through the addition of salts), the filter cake that it generates at the well bore contains some of that flocculated character, and the rate of filtration increases. Conversely, thinners (deflocculants) like lignosulfonates disperse clay flocs, thereby decreasing cake permeability [58]. The loss of liquid from a mud due to filtration is controlled by the filter cake formed of the solid constituents in the drilling fluid. The test in the laboratory consists of measuring the volume of liquid forced through the mud cake into the formation drilled in a 30 minute period under given pressure and temperature using a standard size cell. It has been found in early work that the volume of fluid lost is roughly proportional to the square root of the time for filtration, i.e.

$$V \propto \sqrt{t}$$

The two commonly determined filtration rates are the low-pressure, low-temperature and the high-pressure high-temperature [59].

Test Equipment

The low pressure test is made using standard cell under the API condition of 100 ± 5 psi for 30 minutes at room temperature. Another special cell, will be used to measure filtration rate at elevated temperatures and pressure. Filter press used for filtration tests consists of four independent filter cells mounted on a common frame. Each cell has its own valve such that any or all the cells could be operational at the same time. Toggle valve on the top of each cell could be operated independently for the supply of air for each individual cell. Special high pressure and high temperature filtration tests are run in the laboratory simulating formation temperature and formation back- pressure [60].

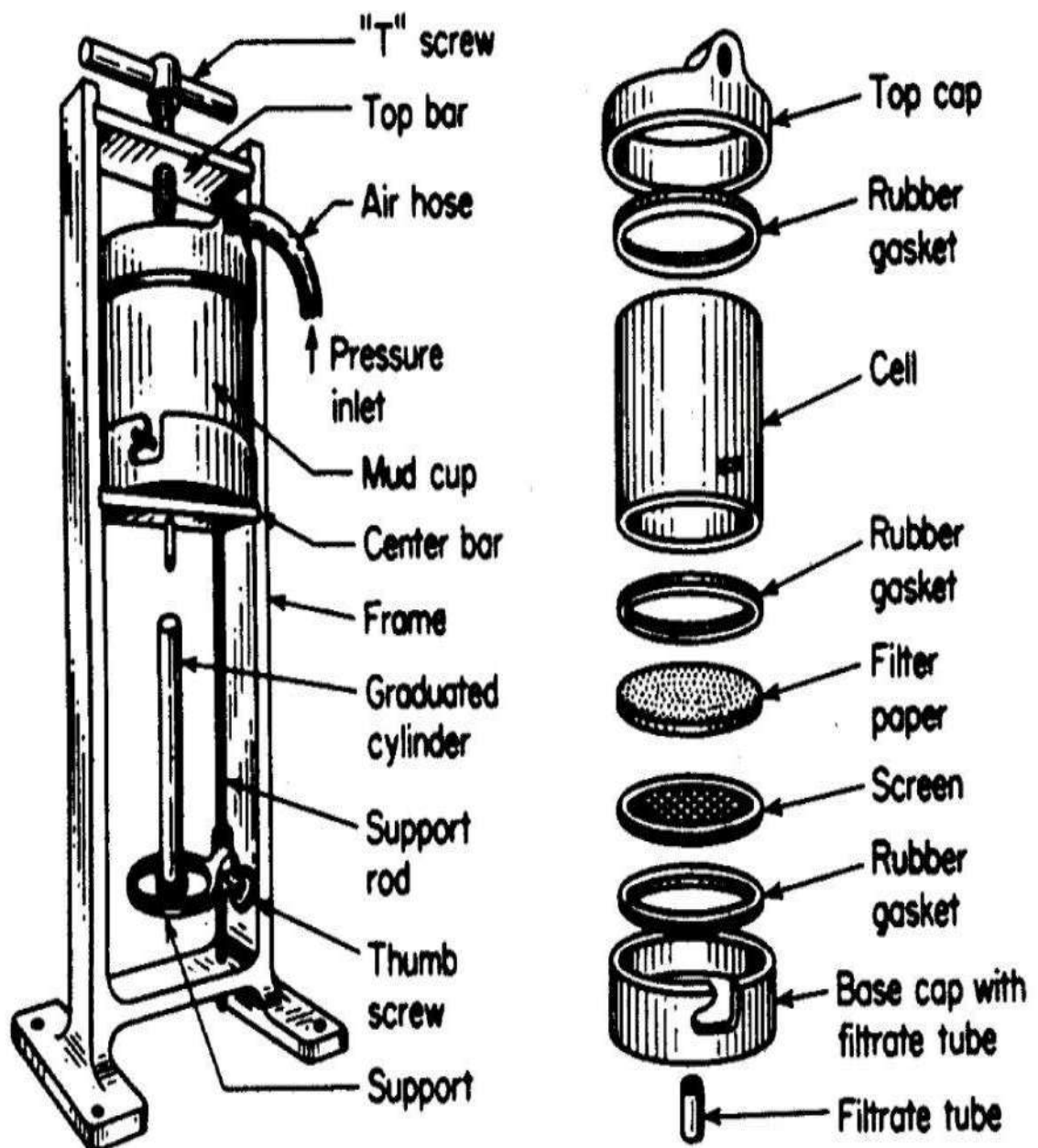


Fig 2.11: Standard API Filter press[76]



Fig 2.12: high Temperature High Pressure filter press [77]

2.9 Summary of Literature Review

The filtration characteristics of drilling fluids and the variables influencing fluid loss during drilling operations have been thoroughly examined in earlier research. The primary cause of filtration is the pressure differential between the formation and the wellbore, which pushes the drilling fluid's liquid phase through the porous formation while solid particles create a filter cake on the wellbore wall. The filter cake serves as a barrier that shields the formation from additional fluid invasion. The impact of temperature on filtration behavior has been the subject of numerous studies. According to reports, drilling fluids become less viscous as the temperature rises, making it easier for the liquid phase to pass through the rock. Increased filtrate loss and modifications to the filter cake's structure result from this. Certain drilling fluid additives may also deteriorate at high temperatures, which lessens their ability to limit fluid loss.

Furthermore, a number of research have looked into how pressure affects filtration. Increased fluid loss at the first stage of filtration is caused by higher differential pressure, which also increases the driving force forcing the filtrate into the formation. But as filtration proceeds, solid particles build up and create a filter cake that progressively lowers the filtration rate. Enhancing filtration control at high pressure and high temperature (HPHT) settings has also been the focus of recent study. To improve drilling fluid stability and lower filtering loss, sophisticated additives like nanoparticles have been added. Drilling fluid performance in deep wells is enhanced by these additives, which assist create a more compact and less porous filter cake.

Chapter 3 Methodology

3.1 Introduction

This chapter explains the method used in this study to investigate the effect of temperature and pressure on drilling mud filtration properties. In the beginning, the study was planned as an experimental work. However, since laboratory experiments were not carried out, the study was completed by reviewing and analyzing published scientific papers related to drilling mud behavior under different temperature and pressure conditions. The methodology focused on understanding how these factors affect filtrate loss, filter cake thickness, and drilling mud performance.

3.2 Research Method

This study was carried out using a literature review method. A number of journal articles, scientific papers, and academic studies were collected and reviewed in order to understand the effect of temperature and pressure on drilling mud filtration properties. The study also considered papers that discussed the effect of additives such as salts, polymers, and nanoparticles on improving drilling mud performance, especially under high-temperature and high-pressure conditions. The purpose of using this method was to gather useful scientific information from previous studies and compare their findings. This helped in building a clear understanding of the relationship between temperature, pressure, and drilling mud filtration behavior without performing laboratory tests.

3.3 Sources of Data

The information used in this study was taken from secondary sources. These sources included published journal papers, research articles, and academic studies related to drilling fluids and filtration properties. The selected sources provided information about different drilling mud systems, testing conditions, additives used, and the main results related to filtrate volume, mud cake thickness, plastic viscosity, and yield point. These studies were used as the main source of data for the analysis and discussion presented in Chapter 4.

3.4 Selection of Papers

The selected papers were chosen based on their relevance to the topic of the study. Priority was given to papers that discussed the influence of temperature and pressure on drilling mud properties. More attention was given to studies that included filtration tests, HTHP conditions, and mud additives. The main points considered during the selection of the papers were:

- the study must be related to drilling mud or water-based drilling fluid
- the paper should discuss temperature, pressure, or HTHP conditions
- the study should include results related to filtrate loss, filter cake thickness, or rheological properties
- preference was given to papers that investigated additives used to improve mud performance

Based on these points, the most relevant papers were selected and used in the literature discussion.

3.5 Method of Analysis

The selected papers were read carefully, and the important information was taken from each one. The analysis focused on the type of drilling mud used in each study, the temperature and pressure conditions, the additives used, and the main results related to filtration and rheological behavior. After collecting the main points from the papers, the results were compared and discussed in a clear way. The analysis mainly focused on:

- the effect of temperature on mud filtration properties
- the effect of pressure on filtrate loss and filter cake formation
- the difference between standard API and HTHP conditions
- the role of additives in improving drilling mud performance

Some charts and figures from the reviewed papers were also included in Chapter 4 to support the discussion and show the results more clearly.

3.6 Limitation of the Method

This study is limited to the review of published papers and does not include original laboratory experiments. Therefore, the conclusions of the study depend on the results reported by previous researchers. In addition, some studies used different mud compositions and testing conditions, which may make direct comparison difficult in some cases.

However, the selected literature provided enough information to understand the main effect of temperature and pressure on drilling mud filtration properties and to discuss the role of additives under different operating conditions.

Chapter 4: Review and Discussion of Previous Studies on the Effect of Temperature and Pressure on Drilling Mud Filtration Properties

4.1 Introduction

Drilling mud filtration is one of the most important properties affecting drilling efficiency, wellbore stability, and formation protection. When the liquid phase of the mud invades the formation, solids are deposited at the borehole wall to form a filter cake. If fluid loss becomes excessive, operational problems such as formation damage, differential sticking, poor hole stability, and increased drilling cost may occur. For this reason, temperature and pressure must be considered carefully when evaluating drilling mud performance, especially in deep wells where high-temperature and high-pressure (HTHP) conditions are encountered.

Published studies show that increasing temperature can alter viscosity, yield point, and filtration characteristics, while elevated pressure intensifies fluid invasion and changes filter-cake behavior. Several researchers have therefore investigated conventional water-based muds as well as modified systems containing salts, polymers, and nanoparticles to improve drilling fluid performance under severe conditions. This chapter reviews selected studies that are directly relevant to the effect of temperature, pressure, contaminants, and additives on drilling mud filtration properties.

The discussion is organized around four main themes: the effect of temperature on rheological and filtration properties, the influence of HTHP conditions on filtration performance, the role of additives in improving fluid loss control, and the effect of contaminants on salt-saturated mud systems.

4.2 Pervious study

Wang [64] investigated the rheological behavior of two high-density water-based drilling fluids under HTHP conditions using a Fann 50SL rheometer. The fluids were evaluated at temperatures from 50 to 220 °C and at a pressure of 5 MPa. Their results showed that temperature strongly affected the viscosity of the fresh water-based fluid. Both apparent viscosity (AV) and plastic viscosity (PV) decreased as temperature increased. In the brine-based

fluid, AV and PV decreased initially and reached their lowest values around 150 °C, after which they increased again. The authors concluded that temperature had a much stronger effect than pressure on the rheological properties of these drilling fluids, although pressure still had to be considered together with temperature under deep-well conditions.

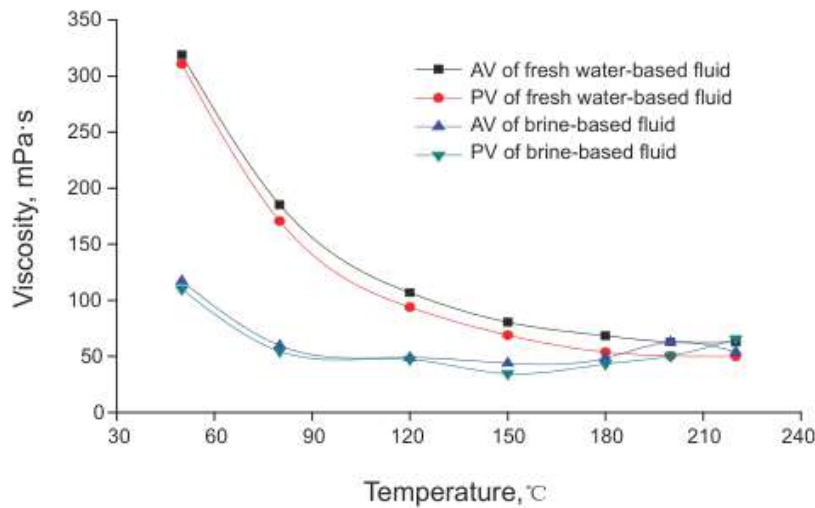


Figure 4.1 Apparent viscosity and plastic viscosity of fresh water-based and brine-based drilling fluids at different temperatures.
[70]

Figure 4.1 confirms that temperature did not affect both fluids in the same way. The fresh water-based mud experienced a continuous decrease in AV and PV, indicating that the mud structure became weaker as temperature increased. By contrast, the brine-based mud retained better rheological stability at higher temperatures. This comparison is important because it shows that mud composition controls how strongly temperature influences drilling-fluid behavior.

Abdulhussien and Salih [61] examined a saturated salt-base mud prepared with sodium chloride and different potassium chloride concentrations to simulate salt-section drilling conditions. Their results indicated that the addition of KCl increased mud stability and reduced the harmful effect of salt dissolution and contamination. They also reported that temperature had only

a slight effect on plastic viscosity in the treated saturated salt mud, while increasing the KCl concentration caused a gradual improvement in rheological stability.

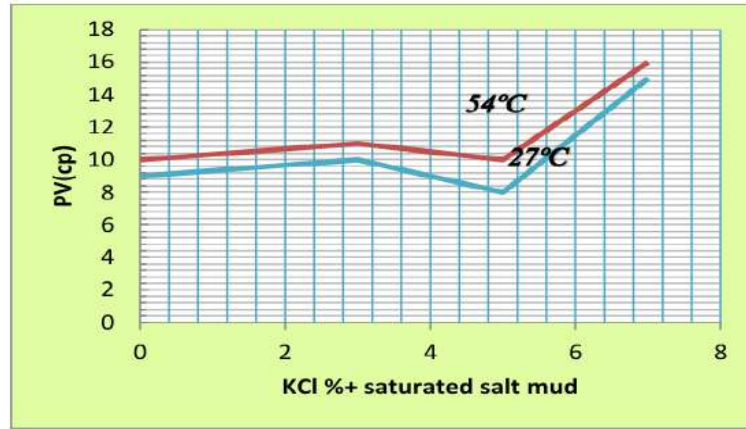


*Figure 4.2 Relation between plastic viscosity and KCl concentration in saturated salt mud at 27 °C and 54 °C.
[67]*

As shown in Figure 4.2, plastic viscosity changed only slightly with temperature, whereas increasing KCl concentration produced a clearer stabilizing effect. The difference between the curves at 27 °C and 54 °C remained limited, which supports the authors' conclusion that temperature alone had a smaller effect than salt treatment on this mud system.

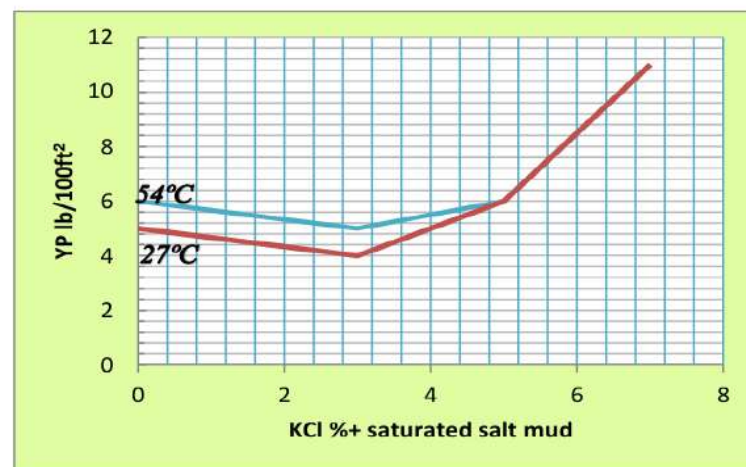


*Figure 4.3 Relation between yield point and KCl concentration in saturated salt mud at 27 °C and 54 °C.
[67].*

Figure 4.3 shows that yield point also responded to KCl concentration. The reported behavior indicates that saturated salt mud treated with KCl maintained more stable yield-point values at elevated temperature than the untreated system. In practical terms, this means that potassium chloride can help preserve the carrying and suspension ability of the mud in salt formations where thermal effects are expected.

Khashay [63] developed a water-based drilling mud containing green-synthesized zinc oxide (ZnO) nanoparticles and tragacanth gum (TG), a biodegradable natural polymer. Rheological properties were analyzed at 25, 50, and 75 °C, and the final HTHP filtration test was conducted at 120 °C and 500 psi. The authors reported that the optimized formulation containing 750 ppm TG and 0.25 wt % ZnO nanoparticles improved plastic viscosity by 27.84%, yield point by 43.16%, reduced fluid loss by 54.16%, and reduced mud cake thickness by 25%.

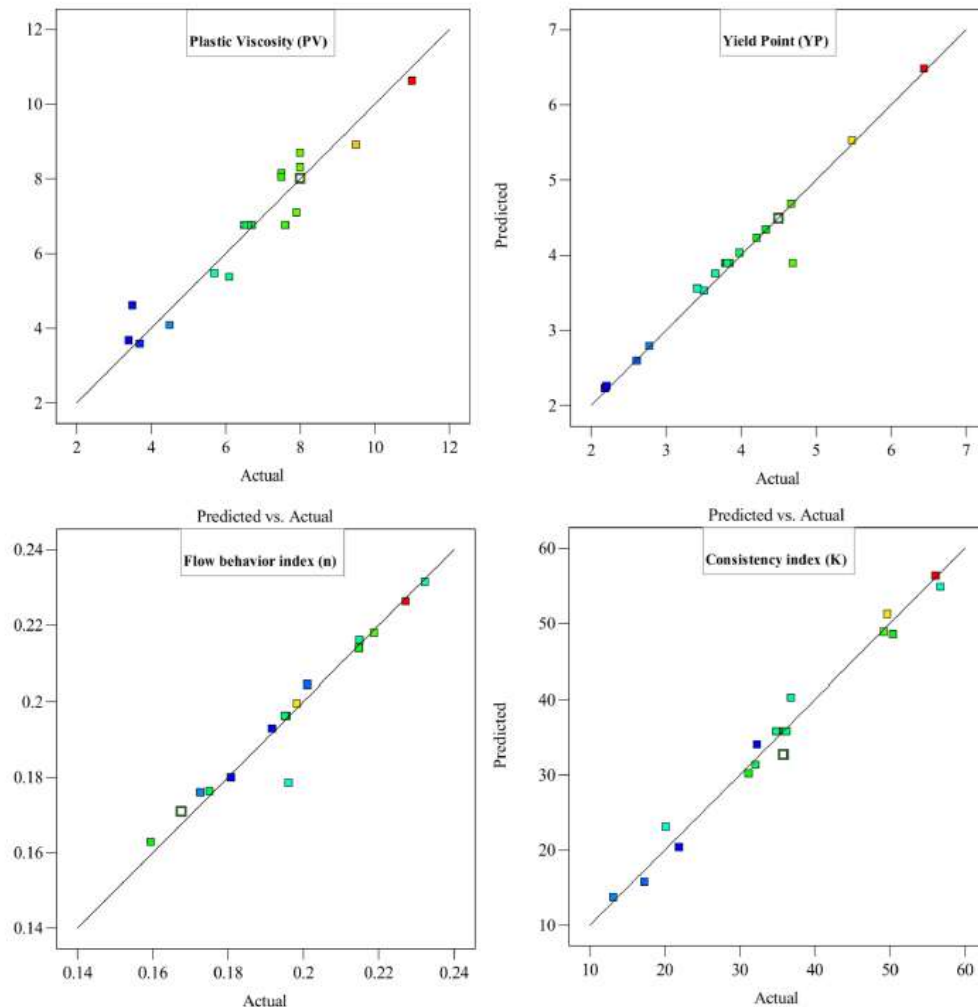


Figure 4.4 Diagnostic plots comparing predicted and actual values of plastic viscosity, yield point, flow behavior index, and consistency index. [69]

Figure 4.4 shows a close match between predicted and actual values of PV, YP, flow behavior index (n), and consistency index (K). This confirms that the developed model represented the rheological behavior of the ZnO–TG drilling mud with good accuracy. The close agreement also strengthens the reliability of the reported temperature-dependent trends.

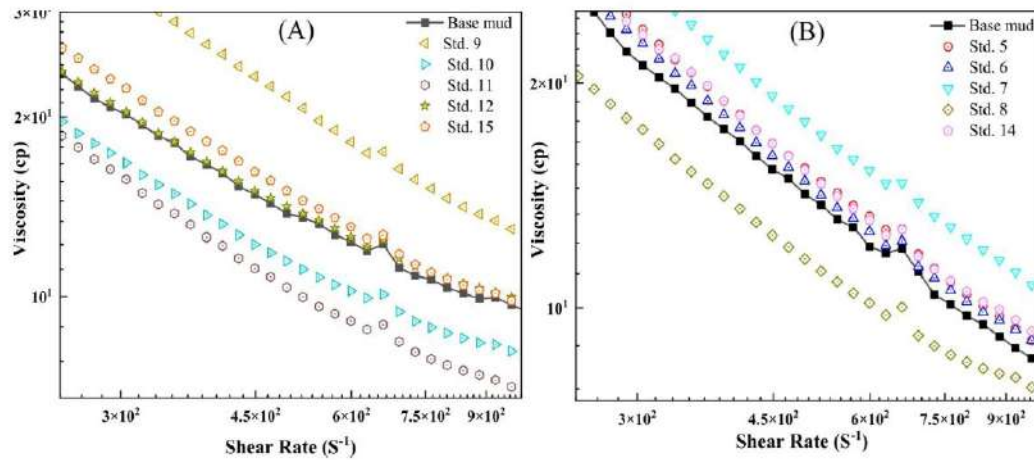


Figure 4.5 Effect of ZnO nanoparticles and tragacanth gum on viscosity of mud samples at 50 °C and 75 °C.
[69]

Figure 4.5 shows that viscosity decreased as shear rate increased, which indicates shear-thinning behavior. This is desirable in drilling fluids because the mud can maintain sufficient viscosity at low shear to suspend cuttings, while flowing more easily at high shear during circulation. The figure also demonstrates that the ZnO–TG formulations retained a useful viscosity profile at 50 °C and 75 °C, indicating improved rheological stability at elevated temperature.

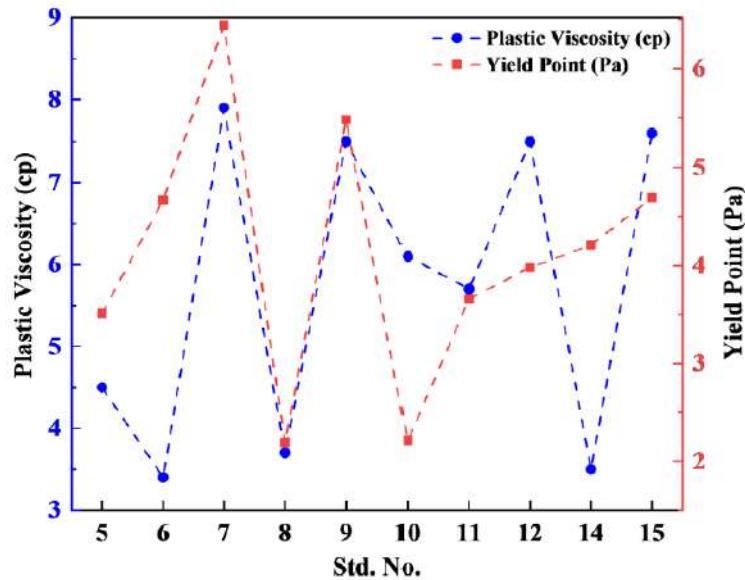


Figure 4.6 Effect of ZnO–TG solutions on yield point and plastic viscosity at elevated temperature. [69]

Figure 4.6 indicates that both plastic viscosity and yield point depended on the formulation of ZnO nanoparticles and tragacanth gum. The optimized samples maintained improved PV and YP under elevated temperature, which means that the ZnO–TG combination not only improved filtration but also strengthened the overall rheological performance of the water-based mud.

Falih [62] investigated the influence of MgO nanoparticles on four water-based drilling fluids: API water-based mud, DURA THERM mud, saturated salt water mud, and polymer mud. Filtration tests were performed at room temperature and 100 psi, and under HTHP conditions at 75 °C and 100 °C with a pressure of 500 psi. The study found that the effect of additives became more meaningful under these severe conditions. The best results were obtained for DURA THERM mud at 0.07 g MgO and for saturated salt water mud at 0.2 g MgO, where filtrate reduction reached 60% at 100 °C.

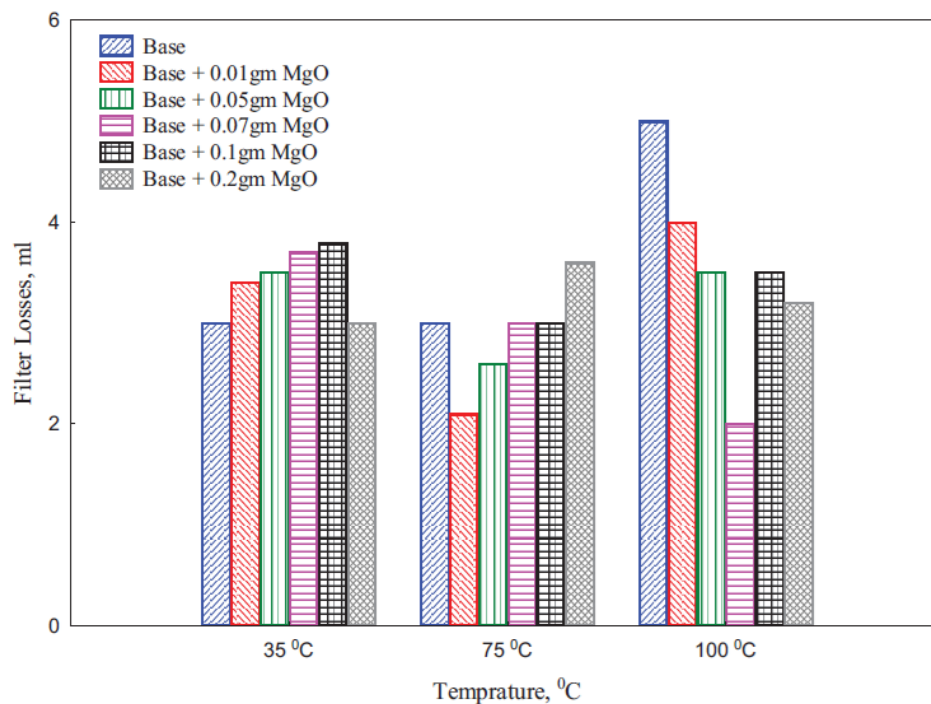


Figure 4.7 Filter losses of DURA THERM mud with MgO nanoparticles at 35 °C, 75 °C, and 100 °C. [68]

Figure 4.7 shows that the difference between the base mud and the MgO-modified DURA THERM mud became clearer at the higher test temperature. At 100 °C, the sample containing 0.07 g MgO produced the lowest filtrate loss among the modified formulations. This supports the authors' conclusion that HTHP testing provides a more realistic evaluation of drilling-fluid additive performance than standard low-pressure tests.

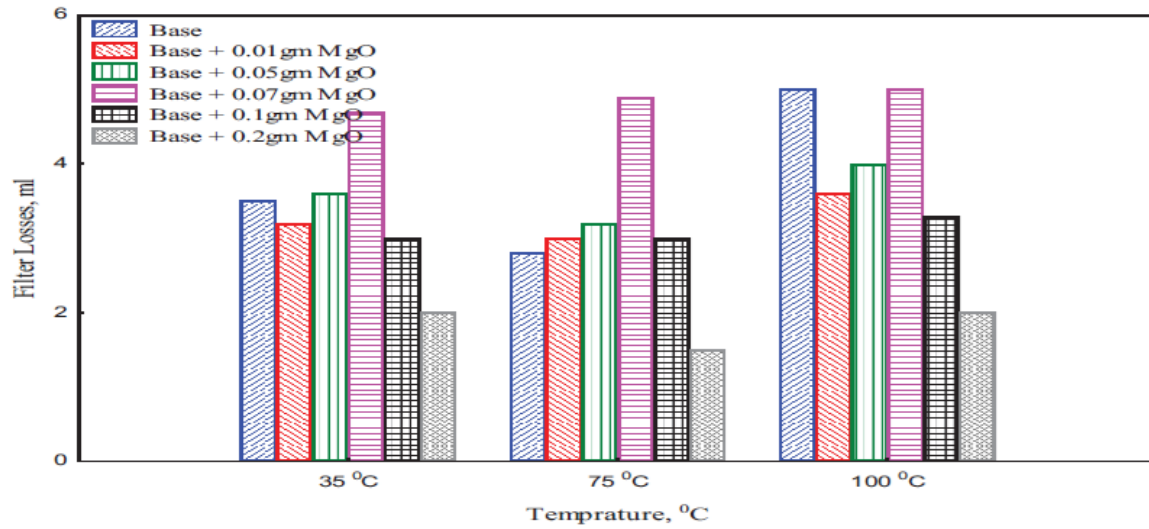


Figure 4.8 Filter losses of saturated salt water mud with MgO nanoparticles at 35 °C, 75 °C, and 100 °C.

[68]

A similar trend can be seen in Figure 4.8 for saturated salt water mud. The modified formulations produced lower fluid loss under HTHP conditions, and the additive effect became more apparent as temperature increased. Although the charts do not isolate pressure as a separate variable, they clearly show the combined effect of higher temperature and higher pressure on mud performance.

Abdulhussien and Salih [61] also studied the effect of contaminants such as salt, shale, and anhydrite on the filtration behavior of saturated salt mud with different KCl concentrations. Their results showed that the addition of KCl reduced the harmful effect of contamination on mud properties and improved overall mud stability. The authors concluded that increasing KCl concentration up to 5% decreased the dissolution of the salt formation and reduced the contaminant impact.

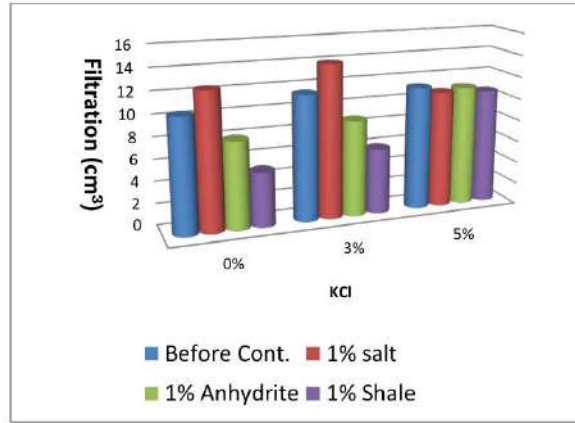


Figure 4.9 Effect of contaminants on filtration of saturated salt mud at different KCl concentrations.
[67]

Figure 4.9 shows that filtrate volume was highest when the mud was contaminated with salt, especially at lower KCl concentration. Increasing KCl concentration to 5% reduced the difference between the uncontaminated and contaminated mud samples, which means that the treated saturated salt mud became more resistant to filtration problems. This finding is useful for drilling abnormal salt sections, where contamination and thermal effects occur simultaneously.

4.3 Comparative Discussion

The reviewed studies reveal several common trends. First, temperature generally has a negative effect on conventional water-based muds because it lowers viscosity, weakens additive performance, and increases the risk of higher fluid loss. This trend is especially clear in the work of Wang et al. for fresh water-based drilling fluid and in the untreated systems discussed by Falih et al. Second, the effect of pressure becomes practically important when it is combined with elevated temperature under HTHP conditions. Under these severe conditions, differences between base muds and modified muds become more visible, which helps identify formulations that can truly withstand downhole environments.

Third, mud composition strongly determines the final response to temperature and pressure. Brine-based or salt-treated systems showed better rheological stability than untreated fresh water-based mud. Likewise, muds containing MgO nanoparticles, ZnO nanoparticles, and biodegradable

polymer demonstrated lower fluid loss and, in several cases, thinner mud cakes under HTHP conditions. These results indicate that additive selection must be matched to the base mud chemistry if effective filtration control is to be achieved.

Overall, the literature suggests that successful drilling-fluid design for high-temperature and high-pressure wells depends on more than a single rheological parameter. The best formulation is the one that maintains balanced viscosity and yield point, limits filtrate invasion, and forms a thin, compact, low-permeability filter cake under realistic drilling conditions.

Chapter Five: Conclusion and Recommendations

5.1 Conclusion

This study investigated the critical impact of Temperature and Pressure on the filtration properties of water-based drilling fluids. Based on the experimental framework and literature review conducted in the previous chapters, the following conclusions are drawn:

Temperature Sensitivity: High temperatures (HT) significantly degrade the physical and chemical stability of drilling mud. As temperature increases, the viscosity of the fluid decreases, leading to a higher volume of filtrate loss and a thicker, less stable filter cake. This is primarily due to the thermal degradation of additives and the dehydration of clay particles like bentonite.

Pressure Impact: Increasing pressure affects the dynamics of filter cake formation. While higher pressure can compress the filter cake, making it denser, it also forces more liquid (filtrate) into the permeable formation if the cake's permeability is not strictly controlled.

synergistic Effects: The combined effect of High-Temperature and High-Pressure (HTHP) is more severe than their individual impacts. Under HTHP conditions, conventional drilling fluids fail to maintain wellbore stability, leading to risks such as differential sticking and formation damage.

Filtration Mechanism: A well-designed drilling fluid must contain a balanced particle size distribution (PSD) to effectively bridge pore throats. The study confirms that the use of deflocculants and specialized polymers is essential to maintaining a thin, low-permeability filter cake under harsh conditions.

5.2 Recommendations

Based on the findings of this research, the following recommendations are offered to improve drilling operations and fluid design:

Enhanced Additive Selection: For deep and ultra-deep wells, it is recommended to use thermally stable polymers and synthetic additives that can withstand temperatures exceeding 150°C without losing their rheological properties.

Optimizing Particle Size: Engineers should ensure the drilling mud has a diverse range of bridging materials. The particle size should ideally be between $1/3$ and $1/7$ of the average pore throat size of the formation to minimize "spurt loss."

Regular Aging Tests: It is crucial to conduct "aging tests" in the laboratory to simulate bottom-hole conditions. This allows for better prediction of how the mud will behave during long periods of inactivity (static aging) or circulation (dynamic aging).

Advanced Monitoring: Utilizing real-time temperature and pressure sensors (like thermocouples or Fiber Bragg grating) during the drilling process can provide critical data to adjust mud weight and composition instantly.

Future Research: Further studies should explore the use of Nano-fluids as additives to enhance the thermal conductivity and filtration control of water-based muds in extreme HTHP environments.

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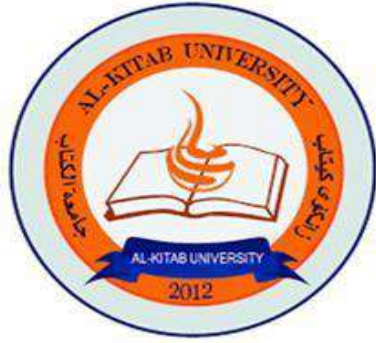
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**College Of Engineering
Petroleum Engineering Department**

**Simulation Study Of PDMS-Based For Oil-
Water Membrane Separation**

A Research Paper

submitted to the Department of petroleum engineering, in partial fulfillment for
the requirements of the degree of bachelors of college of engineering.

prepared by :

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Dedication

- Our parents and brothers who have always supported us and thanks to their efforts we have reached this day.
- Dedicated to our friends who helped us.

Acknowledgment

Thanks to Allah for giving us the ability to complete this research. We thank our family for their continued support and cooperation. We would like to thank our supervisor (Dr. Fryad Mohammed Sharif) for his guidance and discussion. Thank you to all our teachers who taught us during our studies and thank you to all those who helped us with a word, we wish them success. Immense thanks to the Head of College of engineering, Department of petroleum engineering.

Abstract

The separation of oil and water has gained significance in safeguarding the environment and treating industrial wastewater. In this research, a membrane based on polydimethylsiloxane (PDMS) was created and assessed using experimental methods and molecular dynamics (MD) simulation. The goal was to improve separation efficiency, permeability, and hydrophobic characteristics for efficient oil removal.

PDMS membranes were produced through a methodical casting and curing process in an experimental setting. The membranes were evaluated based on surface morphology, wettability, and permeability. Measurements of contact angles validated the hydrophobic characteristics of the PDMS surface, and filtration experiments showed high efficiency in oil rejection along with stable flux across different operating conditions.

In addition to the experimental work, molecular dynamics simulations were performed to explore the interaction mechanisms among oil, water, and the PDMS membrane at the molecular scale. Simulation findings offered insights into diffusion characteristics, interfacial interactions, and the selective transport properties of the membrane. The results indicated that PDMS has a high attraction to oil molecules and a repellent effect on water, improving separation efficiency.

The experimental and simulation results together demonstrate strong alignment and validate that PDMS-based membranes are viable options for effective oil–water separation. This research enhances the understanding of membrane performance and lays the groundwork for improving membrane design in industrial uses.

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Chapter One

1.1 Background of the Study

Oil–water separation is a critical process in many industries such as petroleum production, refining, wastewater treatment, and environmental remediation. Industrial effluents often contain emulsified oil droplets that are difficult to separate using conventional methods like gravity settling or skimming. This has driven the development of advanced separation technologies, particularly membrane-based systems [1].

1.2 Problem Statement

The oil wastewater from factories and industries like petroleum production and chemical processing is a problem for our environment and water. The usual ways to separate oil and water like gravity separation and flotation do not work well when the oil is mixed with water in a fine way.

Using membranes to separate oil and water is a way because it is very efficient and does not use a lot of energy. A material called Polydimethylsiloxane is very good for this because it likes oil and does not like water so it lets the oil pass through. However there are some problems with using this material.

One of the problems is that the membrane gets clogged with oil and it can also swell up when it comes into contact with certain chemicals. It is also not very strong. It is hard to balance how much oil it lets through and how much water it keeps out. The performance of the membrane also depends on things like how thick it is what the holes in it look like and what the pressure is.

It is also hard to understand how all these things affect the membrane because doing experiments can take a time and cost a lot of money. We need to use computers to simulate how the membrane works so we can make it better. We need to use tools that are based on how things move and how they diffuse.

So we need to do a study that combines experiments and computer simulations to see how well the Polydimethylsiloxane membranes work and how we can make them better. This study will look at what affects how well the oil and water are separated and how much fluid can pass through the membrane. We also want to make models that can predict how the membrane will behave so we can design systems for separating oil and water.

The oil wastewater from factories is still a problem and the Polydimethylsiloxane membranes are a good way to solve it. We just need to make them work better by understanding how they work and what affects their performance. The study will help us do that and make the Polydimethylsiloxane membranes a practical solution, for separating oil and water [2].

1-3 Aim of the Study

- To create PDMS-based membranes with regulated composition and arrangement.
- To define the membrane characteristics, encompassing surface structure, wettability, and permeability.
- To assess the efficiency of oil–water separation and the flux performance of the membrane through experimentation.
- To model the molecular interactions among oil, water, and PDMS through molecular dynamics techniques.
- To examine transport processes and interfacial properties at the molecular scale.
- To evaluate experimental findings against simulation results for confirmation and enhanced insight.
- To enhance membrane efficiency for possible industrial and environmental uses.

1.4 Significance Of The Study

This study is really important because we have a lot of problems with wastewater. We need to find ways to treat this water. The amount of oil-contaminated water from petroleum industries and manufacturing is getting bigger. We need to find efficient and cost-effective ways to separate the oil from the water.

Using Polydimethylsiloxane (PDMS)-based membranes is an idea because they can selectively let oil pass through. This study helps us understand how these membranes work in situations.

We did some experiments to see how well the membranes work. We found out that things like pressure how thick the membrane is and what is in the water affect how well the membrane works. If we understand these things, we can make membranes that work well in real life.

We also used computer models to predict how the membranes will work. This way we can try things without having to do a lot of experiments. By combining experiments and computer models we can understand the process better.

The results of this study are important, for reasons:

- Environmental protection: We can reduce oil pollution in our water and make wastewater treatment better.
- applications: We can make oil refineries, petrochemical plants and water treatment plants work better.
- Scientific advancement: We can make membranes and new materials.
- impact: We can save money by making membranes that work well and use less energy.

Over all this study helps us make membranes that are efficient last long and can be used in big industries. This helps companies follow rules and be more sustainable {3}.

1.5 Scope of the Study

This study is about looking at how Polydimethylsiloxane (PDMS)-based membranes work for separating oil and water. We are using two ways to do this: by doing experiments and by using computer simulations.

The scope includes:

- Membrane Fabrication: We make PDMS-based membranes with thickness and structures and then check what they are like.
- Experimental Analysis: We test how well the membranes work with oil and water mixtures in a laboratory. We look at things like
Permeation flux.
Separation efficiency.
Oil rejection rate.
- Operating Conditions: We study how things like
Applied pressure.
Feed concentration.
Temperature (not high or too low) affect the membranes.
- Simulation Study: We create models based on how things move and spread like Ficks Law of Diffusion to Predict how well the membranes will work.
Look at how fluids and masses move and change.
- Performance Comparison: We compare what we find from experiments with what we find from simulations to make sure our models are good and to make the membrane design better.

1.6 Limitations of the Study

- This study has some limitations even though it has some points.
- The experiments were done on a scale in a lab. This may not be the same as what happens in a factory.
- The system that feeds the water and oil mixture is very simple. It does not have all the things that real wastewater has, like salts and dirt.
- The study looks at what happens when the membrane gets clogged. It does not look at this problem over a long time.
- The study only uses membranes made from one type of material. It does not look at materials that might be better.
- The computer model makes some assumptions that might not be true. For example, it assumes that the water is flowing steadily and that the holes, in the membrane are all the size.
- The study does not look at what happens when things get really extreme like high temperatures or pressures. The study of the limitations of the Study and the limitations of the Study are important to consider when looking at the Study and the limitations of the Study.

Chapter Two

Literature Review

2.1 Introduction

With growing production of oily wastewater generated from oil exploration, production, refining and transportation, it is highly problematic for the environment and operation in petroleum industry. To balance environmental requirements with the potential costs, membrane technologies for oil–water separation that can meet strict environmental regulations, reduce treatment expenses and contribute to water reutilization or proper discharge are needed. Traditional separation techniques such as gravity separators, hydrocyclones and the flotation cells are limited in their treatment of stable emulsions, fine oil droplets or low relative oil–water densities. As a result, the membrane separation technology has been intensively studied owing to their advantages of high separation efficiency, low energy consumption and small size[4].

Poly(dimethylsiloxane) (PDMS) is a promising material for oil–water separation among various membrane materials, PDMS is a silicon-based polymer characterized by excellent chemical stability, thermal resistance, mechanical flexibility, and intrinsic hydrophobicity. These properties make PDMS particularly suitable for selectively permeating oil while repelling water, or for surface modification to achieve controlled wettability. Additionally, PDMS membranes can be fabricated with tunable pore structures and surface characteristics, allowing optimization for different oil–water systems [4].

2.2 Molecular Dynamics Simulation

Molecular dynamics (MD) simulation is a computational study of the time evolution of atoms and molecules in Newtonian classical mechanics. In MD, atoms are considered interacting particle's and their movement is determined from force fields which detail bonded and non-bonded interactions. Integrating the equations of motion over discrete time steps, MD yields atomic-scale trajectories that are then used to obtain structural, thermodynamic and transport properties [5].

MD simulations are commonly used to simulate diffusion permeability, interfacial interactions, and material behavior at the molecular level, including polymeric membranes such as PDMS for oil–water separation [5].

2.3 -Overview of Key Properties Calculated in Molecular Simulations

Molecular simulations, especially molecular dynamics, allow calculations of a variety of physical and transport properties from atomistic trajectories. Radial distribution functions, density profiles and chain conformations are widely applied to inspect structural properties. Some thermodynamic values (temperature, pressure and internal energy) are computed from ensemble averages. The transport properties, including diffusion coefficients and permeability, are deduced from mean square displacement and molecular flux analysis. Interfacial properties, including surface tension, wetting behavior, and adsorption, are obtained by applying pressure tensor components and density distributions. These calculations establish a direct relationship between molecular structure and the macroscopic material performance [6].

2.4 Diffusion Coefficient

Diffusion Coefficient, often written as D is a number that shows how fast particles, molecules or atoms spread out or move through a substance like a gas, liquid or solid. It measures how quickly substances mix or move through each other because of heat motion.

2.5 Permeability

Permeability generally refers to the ability of a material or medium to allow substances (such as fluids, gases, or magnetic fields) to pass through it. The specific meaning of permeability depends on the context:

In Physics (Magnetic Permeability): Permeability (symbol: μ) is a measure of how easily a material can support the formation of a magnetic field within itself. It indicates the material's ability to conduct magnetic lines of force. The permeability of free space (vacuum) is denoted μ_0 and is approximately $4\pi \times 10^{-7}$ H/m (Henries per meter) .

In Fluid Mechanics / Soil Science: Permeability refers to the ability of a porous material (like soil, rock, or membranes) to allow fluids (liquids or gases) to pass through it. It depends on the size and connectivity of its pores. This property is critical in fields like hydrogeology, petroleum engineering, and civil engineering.

In Membrane Science / Biology: Permeability characterizes how easily molecules or ions can pass through a membrane, often selective to certain substances. It's important in cellular biology, pharmacology, and filtration technologies.

2.6 MD Application for Pervious Studies

Tamai et al [7] founded the diffusion coefficient of water through PDMS which were $1.53 \times 10^{-4} \text{ Å}^2/\text{fs}$. They conducted molecular dynamics simulations to investigate the diffusion of small penetrants through amorphous polymer membranes. They focused on the diffusion of methane, water, and ethanol in PDMS and PE as well as pure liquid water and ethanol. The study involved calculating insertion probabilities of hard-sphere atoms with varying radii into both the polymers and liquids [7].

Tamai et al [7] used molecular dynamics simulations to investigate the diffusion behavior of methane, water, and ethanol in PDMS and PE polymers. In addition, it presents calculated excess chemical potentials and uses advanced methods to enhance the efficiency of the simulations. They investigated that the computed water diffusion coefficient within PDMS was $1.53 \times 10^{-4} \text{ Å}^2/\text{fs}$, whereas the experimental measurement mounted at $1.45 \times 10^{-4} \text{ Å}^2/\text{fs}$ [7].

Fritz and Hofmann [8] investigated the transport of water-ethanol mixtures through PDMS membranes. The simulation results accurately replicate experimental diffusion coefficients, revealing that water molecules diffuse faster than ethanol molecules. However, despite this faster diffusion, PDMS is found to be preferentially permeable to ethanol due to distinct sorption behavior [8].

Banerjee et al [9] used a quartz crystal mass sensing principle to investigate the diffusion of DMMP and water through a PDMS membrane. They designed a specialized permeation cell that housed a Cu (II) butyrate ethylenediamine-coated quartz crystal sensor. They also calculated the activation energies for the diffusion process based on temperature-dependent diffusion coefficients of DMMP and water. Three different temperatures (100, 120, 150) °C are used to calculate diffusion coefficient and permeability of water and DMMP and the results recorded for calculate diffusion as (1.37, 1.9, 2.91) $\times 10^{-5} \text{ Å}^2/\text{fs}$ for DMMP, and (1.93, 2.65, 4.07) $\times 10^{-5} \text{ Å}^2/\text{fs}$ for water, as well as, the permeability recorded as (19.04, 26.41, 40.45) $\times 10^{-7} (\text{Å}^3 \text{ Å} / \text{Å}^2.\text{fs. atm})$ for DMMP and (1.31, 1.91, 2.93) $\times 10^{-7} (\text{Å}^3 \text{ Å} / \text{Å}^2.\text{fs. atm})$ for water [9].

Merkel et al. [10] studied the permeability and solubility characteristics of PDMS to various gases at 35°C and different pressures. They showed that perfluorinated gases have lower permeability compared to their hydrocarbon counterparts due to their low solubility in PDMS and lower Diffusion coefficients [10].

De Bo, I. et al. [11] investigated the permeability, selectivity, and diffusivity of various gases through a PDMS membrane at 30°C at different range of feed

concentrations. Reducing membrane thickness or increasing feed concentration linearly enhances compound permeation [11].

Singh, D. [12] studied experimental and simulation of the permeation of water through PDMS at different temperature. He investigated that by increasing temperature, membrane is stretched and water permeation through the membrane increased.

Nam, G. et al. investigated the variation of water permeable flow through PDMS by creating interconnected pores through physical treatment and Silwet L-77 as a chemical treatment to modify material properties [13].

Fritz and Hofmann, investigated the behavior of water/ethanol mixtures at the interfaces of different polysiloxanes membranes. These membranes, including PDMS, POMS, and PMPhS. They observed that ethanol molecules preferentially accumulate at the membrane's surface and noted that the membranes swell in the presence of ethanol/water mixtures, with diffusive movement of ethanol molecules hindered in the direction of the water phase [8].

Hofmann et al, utilized atomistic molecular dynamics simulations to explore the transport of various small molecules into flexible chain rubbery polymers and stiff chain glassy polymers. They studied within simulation, diffusion coefficient of water through PDMS as $1.3 \times 10^{-4} \text{ Å}^2/\text{fs}$ compared with experimental result which is $1.45 \times 10^{-4} \text{ Å}^2/\text{fs}$.

Vega and de Miguel investigates the surface tension of various water models like TIP3P, SPC, SPC/E, and TIP4P, as well as newer models like TIP4P/Ew, TIP4P/Ice, and TIP4P/2005 through simulations and assess their agreement with experimental values.[14]

The authors use a thermodynamic route, as proposed by Gloor et al. [15] to calculate surface tension. This method involves estimating the change in free energy associated with a small change in interfacial area while keeping the volume constant. The results obtained using this test-area method is compared to those from the traditional mechanical method that evaluates the pressure tensor. The values of the surface tension as obtained at 300 K from the virial route γ_v and the test-area method γ_{ta} are reported as 54.9 and 54.6 mN/m for SPC model and 59.1 and 58.8 mN/m for TIP5P model, these results compared with experimental which is reported as 71.73 mN/m.

presented a comprehensive study on the interfacial properties of PDMS and its interactions with water using a detailed atomistic force field developed by

Smith et al. [16]. They studied surface tension, interfacial width and water permeation through varying length of PDMS chain ranging from 20 to 100 repeating unit. They investigated at 300 K displaying a surface tension of PDMS, water and interfacial surface tension approximately 23.9 mN/m, 61.8 mN/m and 41 mN/m respectively, and a contact angle of about 108° for chains with 100 repeat units. Ahmed et al [17] demonstrated that the width of the interface in both the PDMS and water layers expands with rising temperatures.

The study revealed that the diffusion constant for low concentrations of water molecules permeating PDMS exhibits significant variability due to "caging" effects caused by local density fluctuations. The diffusion coefficient computed at 300 K for (0.012, 0.06, 0.25) wt% of and at 400 K for (0.012, 0.06) wt% of water, for 300 K it was (2.15, 0.62, 0.56) $10^{-5} \text{ Å}^2/\text{fs}$ for 20 repeat unit and (2.50, 1.04, 0.73) $10^{-5} \text{ Å}^2/\text{fs}$ for 100 repeat unit. For 400 K it was (7.87, 9.05) $10^{-5} \text{ Å}^2/\text{fs}$ for 20 repeat unit and (6.8, 9.54) $10^{-5} \text{ Å}^2/\text{fs}$ for 100 repeat unit. At higher concentrations, aggregation of water molecules leads to phase separation. Lastly, the research observed that the degrees of alignment of methyl groups and siloxane backbones at the interface decrease with temperature but are amplified in the presence of water. Song et al conducted molecular dynamics simulations of two different systems: liquid bulk systems with one nanoparticle added to the center of the simulation box and a system consisting of PDMS with either 10 or 28 repeating units and water with one nanoparticle at the interface. They reported the average mass densities for the simulated water, PDMS with 10 repeating units, and PDMS with 28 repeating units as 971 kg/m^3 , 1017 kg/m^3 , and 1031 kg/m^3 , respectively. They used the periodic perturbation method through non-equilibrium molecular dynamics (NEMD) simulations to calculate viscosity and reported as for SPC water, the estimated viscosity is 0.48 cP, which is consistent with values obtained by other researchers. The viscosities of PDMS with 10 repeating units and 28 repeating units were determined as 7.9 cP and 29.8 cP at 300 K, respectively.

Song et al [18] emphasized the importance of calculating surface/interfacial tension in simulations of liquid-liquid interfaces. In this context, the interfacial tension at the PDMS (10 repeating units)-water interface was found to be $42.2 \pm 0.4 \text{ mN/m}$ [18]. Sun et al [5] employed molecular dynamics simulations to investigate the interfacial properties of water solutions and clusters containing sodium halides, using a conventional force field to describe interatomic interactions. They noticed that MD simulations are highly sensitive to the choice of the cutoff radius for non-bonded

interactions. Among the different cutoff radii tested, the surface tension was closest to a convergence value when the cutoff reached 1.5 nm. This indicates that beyond this cutoff, the van der Waals interactions had a minor effect on the cluster's behavior. The calculated the surface tension and the number density of 1000 and 2000 molecules of water were recorded as 73.87mN/m, 34.727nm⁻³ and 83.48 mN/m , 34.554 nm⁻³ respectively [5].

Ji et al [19] presented a valuable contribution to the understanding of the shear viscosity of PDMS melt through molecular dynamics simulation. They showed the significance of PDMS in micro-electro-mechanical systems and microfluidics, emphasizing the critical role of viscosity in molding processes. They utilized the Green-Kubo formula and LAMMPS for molecular dynamics simulation with using of the united atom force field for PDMS. The viscosity of PDMS increases with the growth of chain dimensions and crosslinking rate. The simulations involve systems comprising 32 chains with Si atoms ranging from 10 to 50 per chain, all conducted at a temperature of 298 K. The results for each chain (10, 20, 30, 40, 50) were (1.593, 5.117, 10.885, 14.104, 22.692) cP respectively [19].

2.7 Emulsification

Emulsification is the process of dispersing one immiscible liquid into another in the form of fine droplets, typically oil and water, to form an emulsion [20].

Types of emulsions

Oil-in-Water (O/W): Oil droplets dispersed in water Examples: milk, many food and cosmetic products.

Water-in-Oil (W/O): Water droplets dispersed in oil Examples: butter, some crude oil emulsions [20].

2.8 Overview of Oil–Water Separation in Petroleum Engineering

Oil and water separation is an important process in petroleum engineering. It is necessary for getting oil out of the ground. We need to protect the equipment and make sure we do not harm the environment. When we get oil out of the ground, we also get a lot of water. This water is called produced water. If we can separate the oil and water properly the oil will be of quality. This also helps to reduce problems when we are operating the equipment. It is safer to get rid of the water or reuse it. Oil and water separation is crucial, for the oil industry.

Nature of Oil–Water Mixtures:

Oil and water can be on their own. They can be mixed together. This mixing usually happens because of a lot of force in places like reservoirs, wellbores, pumps, chokes and pipelines. It also happens when there are things like asphaltenes, resins, waxes and fine solids around. These things help oil and water mix. Oil and water mixtures are classified in ways depending, on which one is the main part [20].

2.9 Membrane Technology for Oil–Water Separation

PDMS as a Membrane Material

In the treatment of wastewater, a membrane made of poly-dimethylsiloxane, which is also known as PDMS is used to separate the mixture of oil and water. This dimethylsiloxane membrane is really good, at separating an oil and water emulsion. The dimethylsiloxane membrane does a great job of splitting the oil and water apart [21].

When an emulsion that has small oil droplets in water like the kind you find in an oil and water mixture goes through a special filter, the membrane something happens to the oil and water emulsion. The oil and water emulsion are made up of oil droplets in water, which is also called an oil, in water emulsion or an O/W emulsion [21].

The thing about PDMS is that it does not like water and it likes oil. So, when you have oil droplets around PDMS they really like to spread out and go through the PDMS membrane. This is because PDMS is hydrophobic, which means it does not like water and it is oleophilic which means it likes oil. The oil droplets like to wet the PDMS and go through it which is an interesting thing, about PDMS [21].

Water is pushed away. It stays on the side where the water is fed in. The water does this because it is repelled. This means the water remains on the feed side of things, so oil gets separated from water. This happens when the mixture of oil and water is very stable and the drops of oil are really small [21].

Chapter Three

Methodology

3-1 Introduction

This chapter presents the methodologies employed to investigate the behavior and interactions of PDMS chains under various conditions using molecular dynamics (MD) simulations. The analysis focuses on demulsification efficiency in oil–water systems.

The chapter introduces the simulation tools used in this study, including LAMMPS, Visual Molecular Dynamics (VMD), Open Visualization Tool (OVITO), Packmol, and Jmol, for system preparation, execution, and analysis.

It further describes the preparation of molecular models such as PDMS with different chain lengths and functional groups, and the creation of simulation boxes designed to study oil–water demulsification. Simulation parameters, including force fields, ensembles, and analysis metrics, are detailed to ensure reproducibility and reliability.

The simulation case addressed as demulsification performance of polydimethylsiloxane-polyethyleneglycol (PDMS-PEG) copolymers in oil–water systems, with varying surfactant and copolymer concentrations.

The methodology includes simulation setup, parameter selection, and analysis of results through calculated properties such as surface tension, viscosity, and total energy.

Theoretical Basis and Calculated Properties in MD Simulations

To model atomic-scale dynamics in siloxane systems, Newtonian mechanics applied within the molecular dynamics (MD) framework, where the motion of atoms governed by classical equations of motion. The equation of motion for an atom in an MD simulation can be expressed as:

$$F_i = \frac{d^2 r_i}{dt^2} m_i \quad 3-1$$

Where; m_i is the mass of atom I. r_i is the position vector of atom i which specifies its coordinates in three-dimensional space (x, y, z) and F_i is the total force vector acting on atom i [22,23]. In order to simulate the dynamics of the particles, it is required that the coordinates (x) and velocity (v) of the particles be defined over short time intervals (dt) based on the force acting on them. This achieved through numerical

integration of the equations of motion, which is often performed using the Verlet algorithm [23,24,25].

Force Field

In terms of MD simulations, a force field is a collection of mathematical expressions and constants that define the bonds and molecular interactions of atoms in the modeled system. Such interactions include the movements between particles in the system such as the stretching of bonds, the bending of angles, rotation of dihedral angles, and the computing of non-bonded interactions like van der Waals forces and electrostatic interactions [26].

There are two main components of a force field **Bonded Interactions** and **non-Bonded Interactions** [26].

Bonded Interaction

Bonded interactions describe the interactions within individual molecules. The potential energy associated with bonded interactions typically includes three terms [26]:

a) Bond Stretching: Described by the harmonic potential:

$$E_{bond} = \frac{1}{2} K_r (r - r_0)^2 \quad 3-2$$

Where; E_{bond} is the bond stretching energy, K_r is the force constant for the bond term, r is the bond length in the simulation and r_0 is the equilibrium bond length.

b) Angle Bending: Described by the harmonic potential:

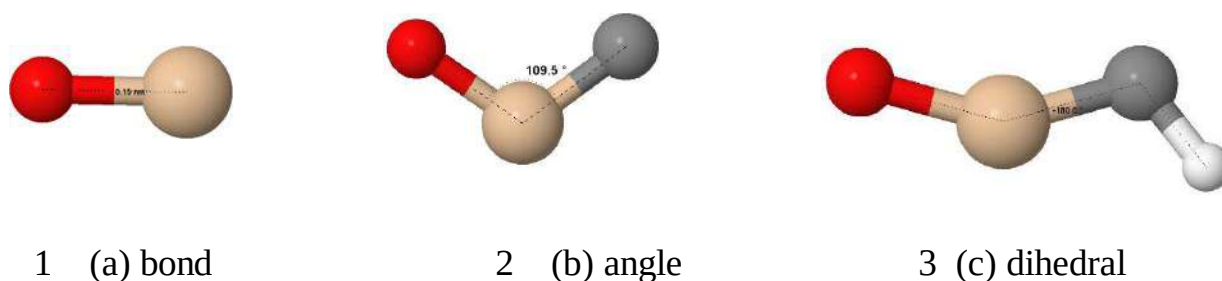
$$E_{angle} = \frac{1}{2} K_\theta (\theta - \theta_0)^2 \quad 3-3$$

Where; E_{angle} is the angle bending energy, K_θ is the force constant for the angle term, θ is the angle between bonded atoms and θ_0 is the equilibrium angle.

c) Torsional (Dihedral) Rotations: Described by a periodic potential:

$$E_{dihedral} = k_t [1 + \cos(n\phi)] \quad 3-4$$

Where; $E_{dihedral}$ is the torsional energy, k_t is the force constant for the torsional term, n an integer $> = 3$, and ϕ the torsion bond angle.



Figur3-1 Types of bonded interaction

Color Code: O, red; Si, yellow; C, gray; H, white.

Nonbonded Interactions

Nonbonded interactions refer to interactions between atoms or molecules that are not directly bonded. These interactions often involve Lennard-Jones potentials and coulombic (electrostatic) interactions [26].

a) Lennard-Jones Potential: The Lennard-Jones potential describes attractive force interaction and repulsive force interaction. The Lennard-Jones Potential is given in **Equation 3-5**:

$$E(r) = 4 \epsilon \left[\left(\frac{\sigma}{r} \right)^{12} - \left(\frac{\sigma}{r} \right)^6 \right] \quad r < r_c \quad \text{3-5}$$

Where; $E(r)$ is the Lennard-Jones energy, ϵ is the depth of the potential well, σ is the distance at which the potential is zero, r is the distance between two interacting atoms and r_c is the cutoff distance used in molecular dynamics simulations to truncate the van der Waals interactions beyond this distance for computational efficiency.

b) Coulombic Attraction: It refers to the attractive force between two opposite charge particles and called electrostatic attraction. The coulombic interaction is given by Coulomb's law:

$$E_{Coulomb}(r) = k_q \frac{q_1 q_2}{r} \quad \text{3-6}$$

Where; $E_{Coulomb}(r)$ is the coulombic energy (Kcal/mol), q_1 and q_2 are the charges of the interacting atoms. k_q is the proportionality constant for the electrostatic potential energy and r the distance between the charged atoms.

Statistical Mechanics and Thermodynamic Ensembles

A system can be described using an ensemble, or statistical ensemble, which is a theoretical framework consisting of multiple copies of the system, each representing a potential state the real system might occupy. When this collection is in statistical equilibrium, it is referred to as a thermodynamic ensemble. This method enables the determination of properties for real thermodynamic systems by applying principles from classical and quantum mechanics. In molecular simulations, the focus is typically on three main ensembles: (NVE, NVT, NPT) [27].

Microcanonical ensemble (NVE)

It represents a system that is completely isolated from its surrounding with constant number of particles (N) and a fixed volume (V), which is why it is often referred to as the NVE ensemble. While the total energy of the system is fixed, temperature fluctuates around an average equilibrium value (T). In statistical mechanics, the microcanonical ensemble is utilized to describe all possible states of a system with a given total energy [27].

Canonical ensemble (NVT)

In a canonical ensemble, the material property studied at constant number of particles N , internal energy E , and volume V . In a canonical ensemble, the energy is able to fluctuate while still being in contact with the heat bath; this is in contrast to the microcanonical where energy remains constant. The canonical ensemble is especially useful for describing the Helmholtz free energy of a system [27,28].

Isothermal-Isobaric ensemble (NPT)

In the isothermal-isobaric ensemble, the number of particles maintains constant and the system's volume can change to ensure that its internal pressure matches the external pressure. The system can exchange energy with its surroundings, but matter remains confined within the system. It is especially relevant in chemistry, as many key chemical reactions occur under constant pressure. The isothermal-isobaric ensemble is indispensable in the description of the Gibbs free energy, which is the mechanical work achievable by the system under constant pressure (p) and temperature (T) [28].

Surface Tension

Surface tension was calculated according to the Irving-Kirkwood definition, **Equation 3-7**, which involves computing the difference between the normal and tangential components of the pressure tensor. The pressure tensor components P_{xx} , P_{yy} , and P_{zz} were calculated during the simulation using the compute pressure command in LAMMPS. These components were averaged over a sufficient simulation time to ensure statistical accuracy [28].

$$\gamma = \frac{L_z}{2} \{ P_{zz} - \frac{1}{2} (P_{xx} + P_{yy}) \} \quad \text{3-7}$$

Where P_{xx} , P_{yy} , P_{zz} is pressure tensor component in x, y, z direction respectively (atm), L_z the length in the z-direction of the simulation box (Å)

Viscosity

The Green-Kubo relation was used to calculate the viscosity of siloxane as shown in Equation 1-8, which relates the viscosity to the integration of the autocorrelation function of the off-diagonal stress tensor components. The stress tensor components and their autocorrelation functions were calculated during the simulation using the fix ave/correlate command. The viscosity was then obtained by integrating these functions according to the Green-Kubo relation [29]:

$$\eta = \frac{V}{K_B T} \int_0^\infty \langle P_{\alpha\beta}(0) P_{\alpha\beta}(t) \rangle dt \quad \text{3-8}$$

where V is the system volume (Å³), k_B is the Boltzmann constant (1.380649×10^{-23} J/mol.K), T is the temperature (K), and $P_{\alpha\beta}$ are the off-diagonal components of the stress tensor (atm). The average viscosity is computed as the mean of the integrated autocorrelation functions for all relevant stress tensor components.

3-2 Simulation Tools and Analytical Programs Used in This Study

The LAMMPS package was chosen as the main simulation tool because of its wide applicability and effective approach to large molecular scale systems. VMD was used for the molecular level visualization and analysis, and OVITO for post simulation data analysis such as diffusion and contact area computations. Utilizing Packmol, we generated the initial configurations, and to adequately capture molecular interactions, we sourced the force field parameters from pre-existing libraries.

Visualization and Analysis Tools

This research relied on the two important software VMD and OVITO for structure preparation and data analysis. VMD was employed in constructing and visualizing molecular structures and in setting of the initial conditions of the simulation systems [30,31]. On the other hand, OVITO was mainly used for analysis after completing a particular simulation. It enabled the assessment of structures such as the contact area, density profile, and distribution of molecules. In addition, the powerful visualization capabilities of diffusion processes aided the recognition of such phenomena as surface spreading and condensation [30]. All these tools combined made certain that the preparation, analysis, and even the presentation of molecular dynamics simulation results in clear and accurate.

Packmol for system initialization

The initial simulation system configurations were generated by packing the molecules in a given spatial distribution using Packmol. This software proves particularly useful in generating packing of dense and non-overlapping molecules while obeying fixed spatial restraints. It is reduced the need for lengthy equilibration phases at the beginning of the simulation procedure which resulted in improved overall computational efficiency [30].

Jmol for Molecular Structure Design

Jmol was used in designing and visualizing the structures of the molecules relevant to the study. Its interactive 3D visualizations provided an accurate way of making and changing molecules like PDMS chains, as well as functionalized siloxane structures. The software Jmol assisted in the drawing of molecular geometries, such as the attachment of fluorine containing alkyls or methyl groups to siloxane backbones [31,32]. By using Jmol, the initial molecular configurations were created efficiently and could be directly integrated into downstream tools like Packmol for packing and LAMMPS for molecular dynamics simulations.

3-3 Molecular Model Preparation

Structure Design

Jmol software was utilized to design molecular structures for various molecules, including silicon dioxide and water, siloxane copolymers (PDMS-PEG) and sodium dodecyl sulfate (SDS) as surfactants as shown in **Figure 3-2** and **Figure3-3**, **Figure 3-4** and **Figure 3-5**,

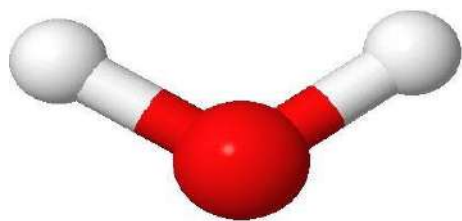


Figure 3-2 Molecular structure of water
Color Code: O, red; H, white

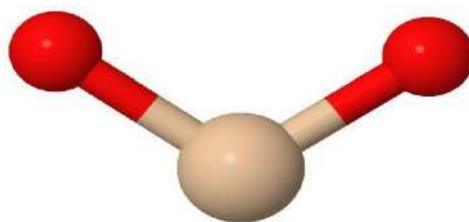


Figure3-3 Molecular structure of silicon oxide
Color Code: O, red; Si, yellow

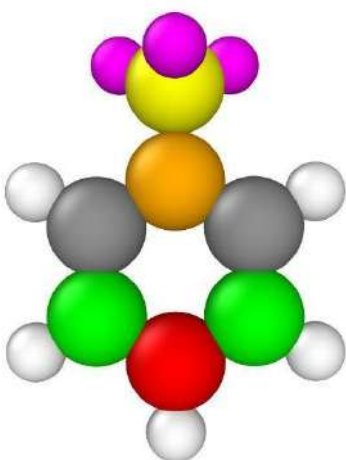


Figure 3-5 Molecular configuration of toluene
Color Code: CAO, gray; CAM, green; CAT, orange; CAP, red; CTT, yellow, HAT, white: HT, pink

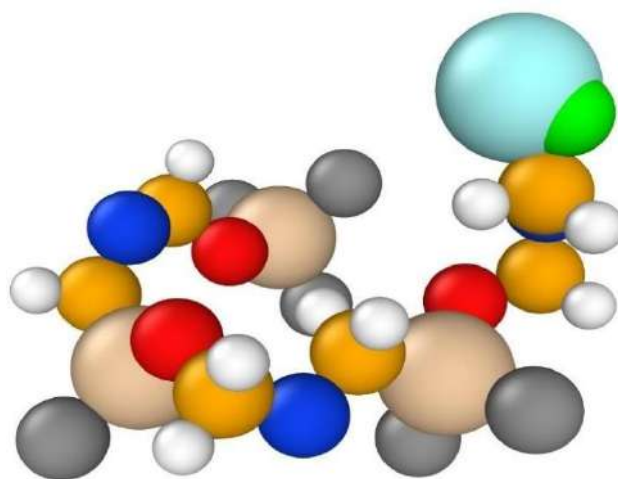


Figure 3-4 Molecular configuration of siloxane copolymer,
Color Code: O-PDMS, red; C-H₃-PMS, Gray; H, white; H-O, Cyan; O-H, Green; C-PEG, Orange; O-PEG, Blue; Si, Yellow

The next step, structures of atoms and molecules are converted into pdb file or xyz file which is important for creating LAMMPS data file. This step could be done by inputting command (write filename.xyz) or (write filename.pdb) into Jmol script console.

The xyz files are replicated and then the configuration the simulation box is created using Packmol. The input file in Packmol can be run via programming language called Julia through two commands, firstly (Julia> using Packmol) then (Julia> run_packmol). The output from this input file will convert into LAMMPS data file via VMD after inputting type of atoms, mass, charge and dimensions as shown in. LAMMPS data file consider the main data file for running molecular dynamic simulation.

Preparation Simulation Box and Simulation Details

The purpose of simulation box is to study the demulsification process to stabilize the water/oil interface by copolymer of PDMS and PEG.

The methodology represented by improving the efficiency of copolymer (PDMS and PEG) as demulsifies in oil-water emulsions involves a series of key steps aimed at understanding how their properties contribute to emulsion destabilization and oil removal. The methodology of this case divided into five parts. The purpose of the first three parts is to validate the input scripts and parameters by comparing with data of literature review. In the first part of last case of methodology, the simulation box were created to contain 50 molecules of toluene in dimension ($20 \text{ \AA}^2$, $25 \text{ \AA}^2$, $65 \text{ \AA}^2$) to evaluate the interfacial surface tension and viscosity of toluene as shown in **Figure 3-6**. In the second part we mixed 50% of water molecules with 50% of toluene molecules in simulation box with dimensions ($25 \text{ \AA}^2$, $30 \text{ \AA}^2$, $70 \text{ \AA}^2$), **Figure 3-7**, to see how the water effect on interfacial surface tension and viscosity of water/oil interface, then in **Figure 3-8** the third part we added 15% of sodium dodecyl sulfate as a surfactants to the oil/water mixture to evaluate the effect of surfactants on interfacial surface tension and viscosity and to validate the methodology with literature review

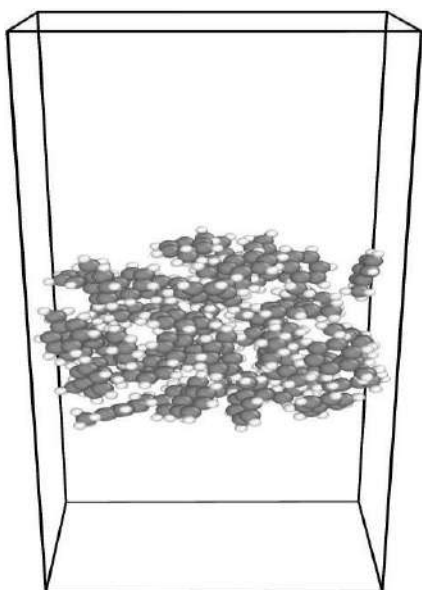


Figure 3-6 Configuration of simulation box of 50% toluene and 50% of water

Color Code: Toluene, gray and white; water,

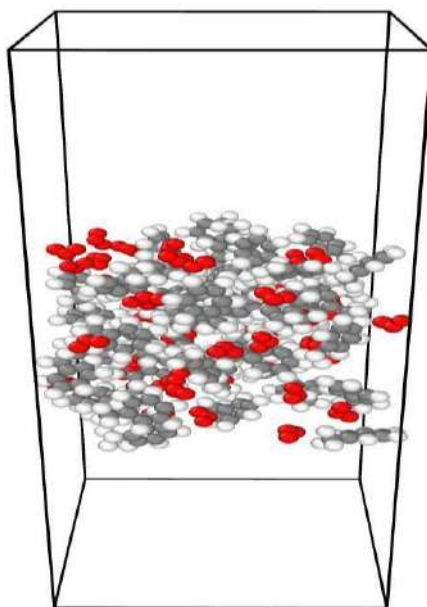


Figure 3-7 Configuration of Simulation box of water/toluene interface

Color Code: Toluene gray and white; water, red; Oxygen

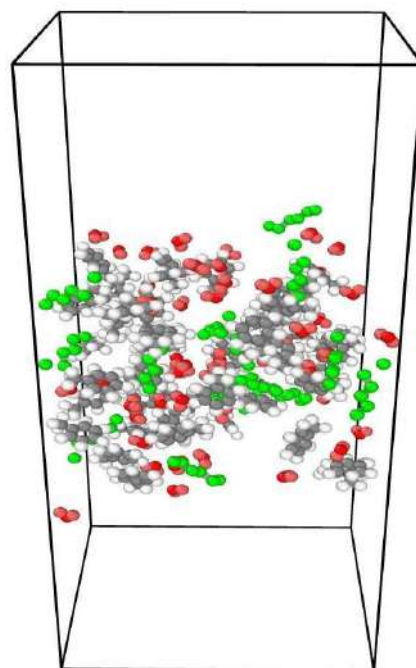


Figure3-8 Configuration of Simulation Box of water\Toluene interface with 15% of surfactant

Color Code: Toluene gray and white; water ,red ;oxygen, Surfactant ; green

In the fourth part, we created four boxes with (17%, 35%, 55%, 80%) of water ratio to constant mixture of (68.5% toluene, 20.5% of Sodium dodecyl sulfate (SDS), as surfactants, 11% of copolymer) as shown in **Figure 3-9** to evaluate the optimum ratio of water. The purpose of adding surfactants is to prevent the oil droplets from immediately coalescing or phase-separating, mimic real-world conditions because many emulsions in oil/water systems naturally contain surfactants, as well as, to allows us to test the efficiency of demulsifies in destabilizing the interface. At the end, the final part of this methodology involved choosing one ratio of water/oil mixture that the results of simulation are closer to optimum results, then we insert (7%, 25%, 35%, 55%, 65%) concentration of (PDMS-PEG) copolymer as shown in **Figure 3-10** to determine the optimum ratio of copolymer. The analysis of simulation in this case involves a comprehensive approach to understanding the behavior and properties of siloxane co-polymers. It starts with simulating oil-water emulsions to characterize the interfacial tension and viscosity, to observe the formation and interaction of the oil and water phases. Next, the focus shifts to how siloxane co-polymers act as de-emulsifiers by destabilizing the oil-water interface through their low surface tension. Finally, the de-emulsification efficiency is quantified by three key steps; First, density profiles for oil and water are computed separately along the axis perpendicular to the interface to visualize their spatial distribution and assess the degree of phase separation. Next, an overlap or mixing metric is calculated by quantifying the region where the density profiles of oil and water coexist, providing insights into the extent of mixing at the interface. Finally, the de-emulsification efficiency is quantified through three key steps. First, density profiles for oil and water are computed separately along the axis perpendicular to the interface to visualize their spatial distribution and assess the degree of phase separation. Next, the total initial overlap between oil and water molecules is calculated at the start of the simulation, followed by the total remaining overlap after a set period. Finally, the de-emulsification efficiency is determined using the formula:

$$DE\% = \frac{\text{Total initial overlapp} - \text{Total remaining overlapp}}{\text{Total initial overlapp}} \quad 3-9$$

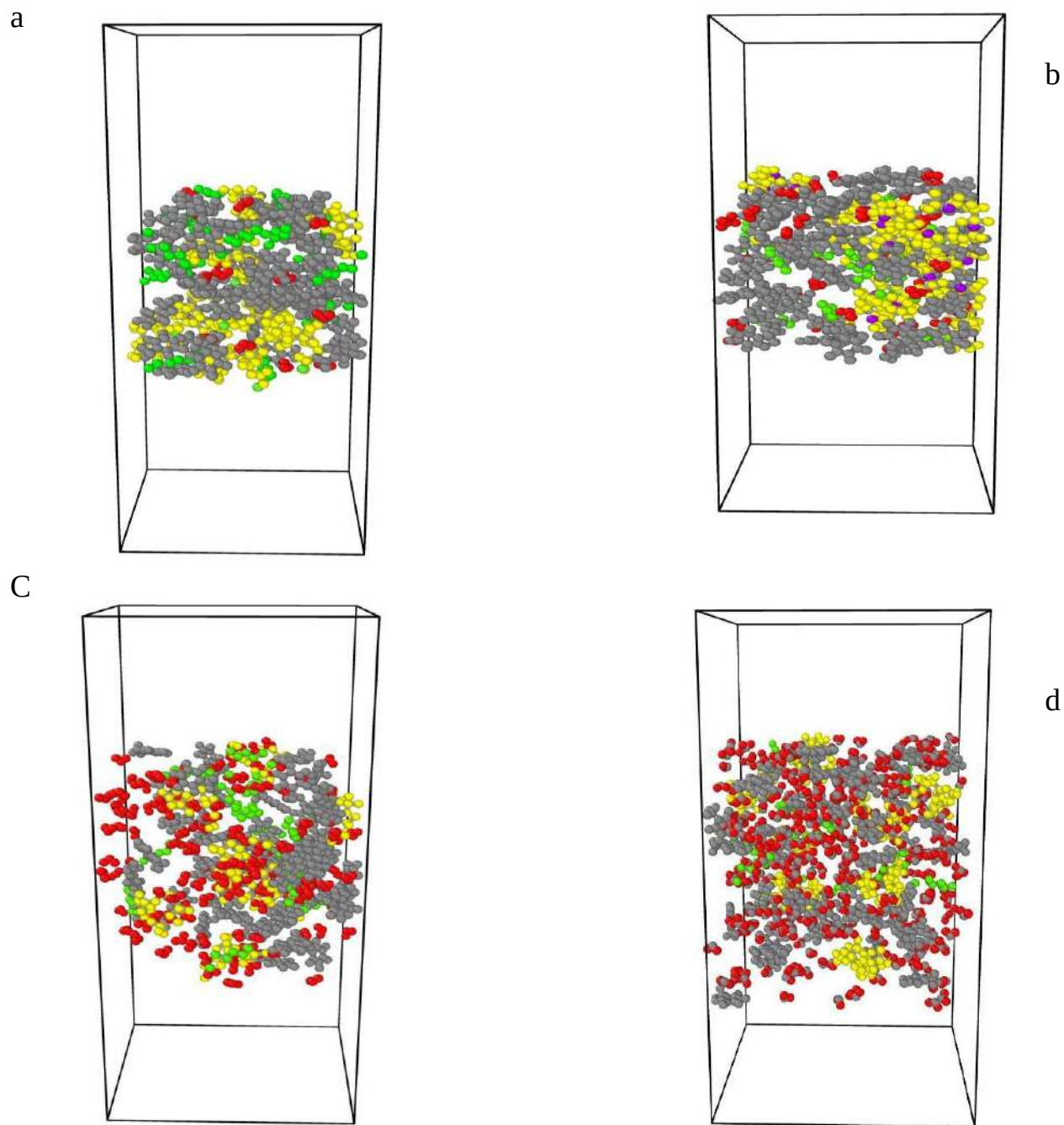


Figure 3-9 Configuration of simulation box of different concentration of water into toluene with 15% of surfactant mixture a) 17% of Water. (b) 35% of water. (c) 55% of water (d) 80% of water
 Color Code: Toluene, gray; water, red; Surfactant, green; siloxane copolymer, yellow

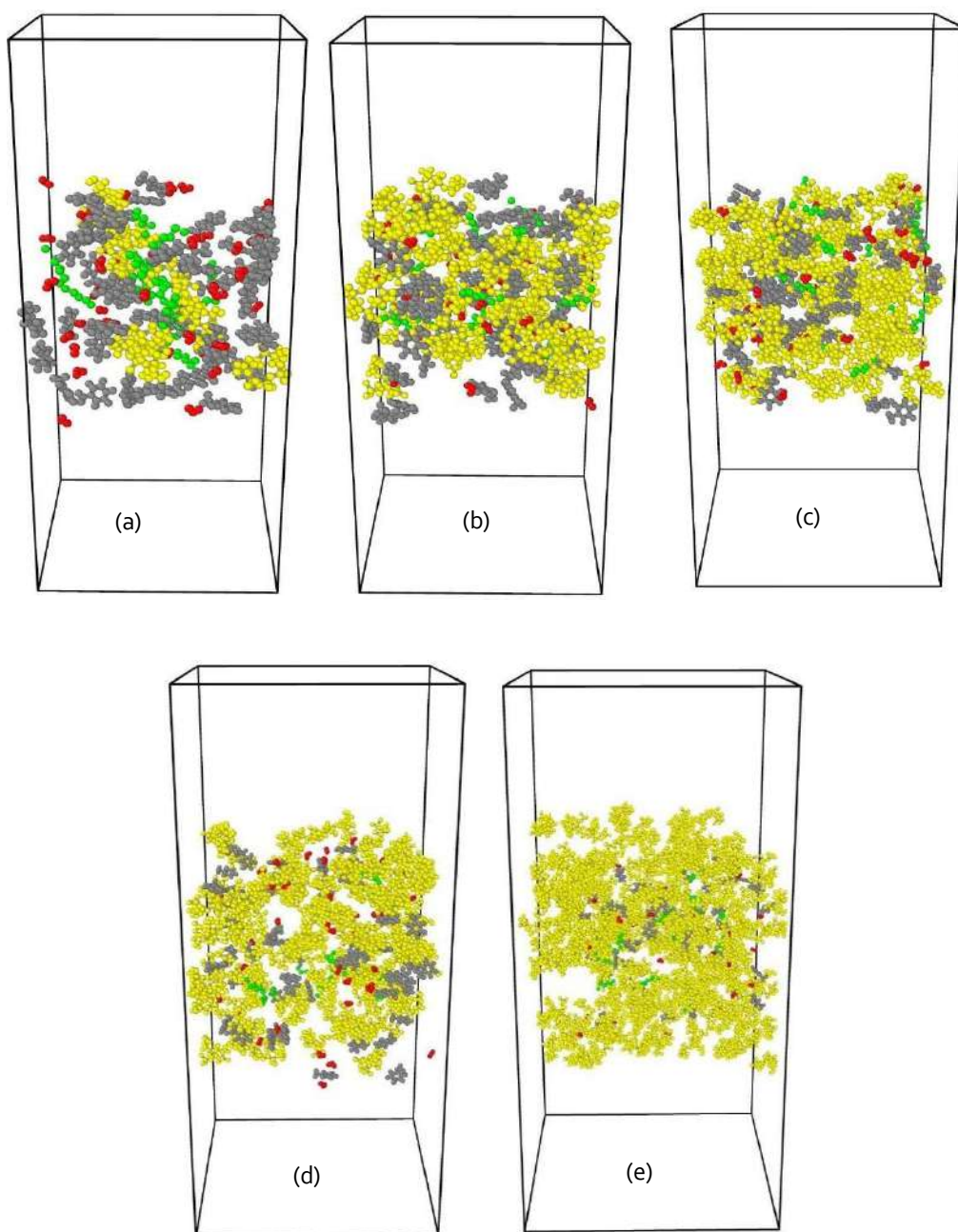


Figure 3-10 Configuration of simulation box of different concentration of siloxane copolymer into constant concentration of water a)7% of Copolymer (b) 25% of Copolymer (c) 35% of Copolymer (d) 55% of Copolymer.

Color Code: Toluene, gray; water, red; Surfactant, green; siloxane copolymer, yellow

Chapter four

Results and Discussion

Simulation-Based Evaluation of Siloxane Copolymer Performance for Water–Toluene Demulsification

4-1 Validation of methodology

The comparison of the simulation method was carried out through the evaluation of surface tension and viscosity for the systems: Toluene, Toluene-water (50:50 %), and Toluene-water- with 15% of SDS. The results of the simulation were compared against the literature as shown in **Table 4-1** and **Table 4-2**, while **Figure 4-1** and **Figure 4-2** provides a graphical representation of the agreement between the modeling and actual experiments.

For pure toluene, the surface tension was determined to be 26.65 mN/m, which is quite close to the report of Rafati and Ghasemian [30] 28.44 mN/m , Kahl et al. (27.76 mN/m), and Fröba and Leipertz (26.79 mN/m). Similarly, pure toluene's viscosity simulation yielded a value of 0.395 mPa.s and appears to be consistent with the corresponding literature data, among them Harris who calculated it at 0.5542 mPa.s and Bolat et al. (0.4316 mPa.s). These small gaps may result from differences in temperatures, the conditions of the experiments, and the parameters of the simulations, but the agreement itself tends to validate the approach.

During the simulation of a 50 percent water-toluene mixture, the surface tension was raised to 34.45 mN/m, which tallies with Saïen findings (35.7 mN/m). This increase can be explained in terms of the water and toluene's mutual insolubility, in which the water's polarity and strong repulsion from the nonpolar toluene molecules lead to increased interfacial tension. The viscosity increased as well to 0.49 mPa.s, in accordance with Caetano et al.'s reported value of 0.555 mPa.s, this provides further confirmation regarding the system's potential to reproduce the interfacial activity of binary systems. The addition of 15% SDS lowered the surface tension of the water-toluene solution to 30.32 mN/m, which is in correspondence with the value reported by Saïen and Akbari at 29.9 mN/m. This reduction shows how the surfactant can reduce effective resistance, improving interfacial separation, and stabilizing the system. As anticipated, the viscosity dropped to 0.218 mPa.s, consistent with other cited reporting such as Santos et al. (0.3 mPa.s) and Avgeri et al. (0.2 mPa.s). The reduction in viscosity due to surfactant effects shows their role in improving molecular motion at the interface, making separation easier. The comparison of

simulation results against several references from literature validates the methodology used.

Table 4-1 Effect of Compositions on Surface Tension (mN/m) of Toluene-Based Systems

System	This Study			
Pure Toluene	26.65	28.44 [114]	27.76 [115]	26.79 [116]
50% water+50% Toluene	34.45	35.7 [119]		
50% water+50% Toluene+15% SDS	30.32	29.9 [121]		

Table 4-2 Effect of Composition on Viscosity(mPa.s) of Toluene-Based Systems

System	This Study		
Pure Toluene	0.395	0.5542 [117]	0.4316 [118]
50% water+50% Toluene	0.49	0.555 [120]	
50% water+50% Toluene+15% SDS	0.218	0.3 [122]	0.2 [123]

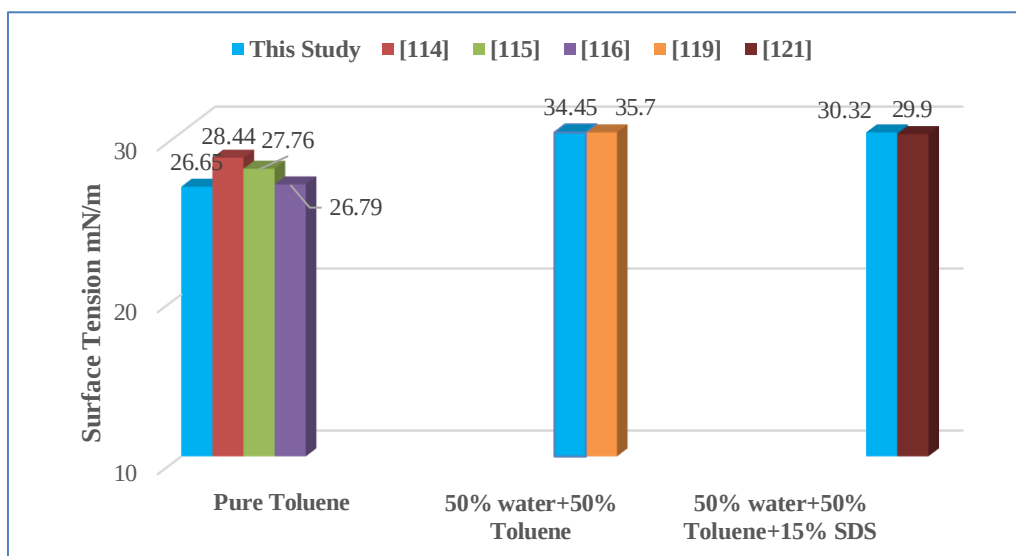


Figure 4-1 Surface Tension Comparison Across Systems and References

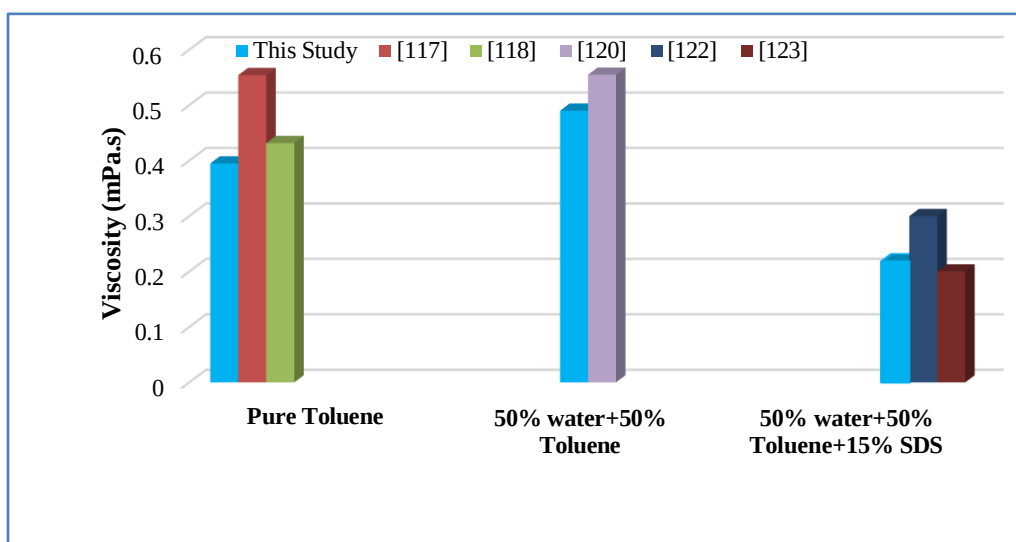


Figure 4-2 viscosity comparison systems and reference

4-2 Evaluation of Increasing Water Concentration on Water/Toluene Interfacial Properties

Table 4-3, Figure 4-3 and Figure 4-4 showed the impact of varying water concentrations on the interfacial properties of the water-toluene system, specifically focusing on surface tension and viscosity, and its implications for phase separation. The observed surface tension increased significantly from 28.54 mN/m at 17% water to 56.89 mN/m at 80% water, indicating a direct correlation between water content and interfacial tension. This rise is attributed to the increasing presence of polar water molecules in a predominantly nonpolar toluene environment, which leads to heightened immiscibility and interfacial resistance. The nonpolar nature of toluene and the strong hydrogen bonding within water molecules amplify the interfacial forces, making the separation of the two phases more challenging as water content rises. Similarly, viscosity also showed a consistent increase, from 0.191 mPa.s at 17% water to 0.378 mPa.s at 80% water. The higher viscosity reflects the structural rigidity introduced by the polar water phase, which hinders the free movement of molecules in the mixture. This trend indicates that as the water concentration increases, the system becomes more resistant to flow, further complicating the separation process. Both the rise in surface tension and viscosity underline the challenges associated with phase separation in water-rich systems, as higher interfacial resistance makes it more difficult to achieve efficient demulsification. The data strongly highlight the necessity of introducing effective demulsifiers, such as siloxane copolymers, to address the increasing interfacial tension and viscosity. Effective demulsifiers could lower the surface tension and disrupt the water-oil interfacial structure, facilitating the separation process. This phase provides crucial insights

into the behavior of water-toluene systems at varying concentrations, demonstrating that higher water content exacerbates interfacial challenges, thereby requiring tailored solutions for efficient separation. These findings underscore the importance of optimizing demulsifier concentration and type for water-rich systems in industrial applications.

Table4-3 Effect of Increasing water concentration on Water/Toluene Interfacial Properties

Ratio of Water to Toluene	Surface Tension (mN/m)	Viscosity (mPa.s)
17%	28.54	0.191
35%	32.82	0.26
55%	43.22	0.321
80%	56.89	0.378

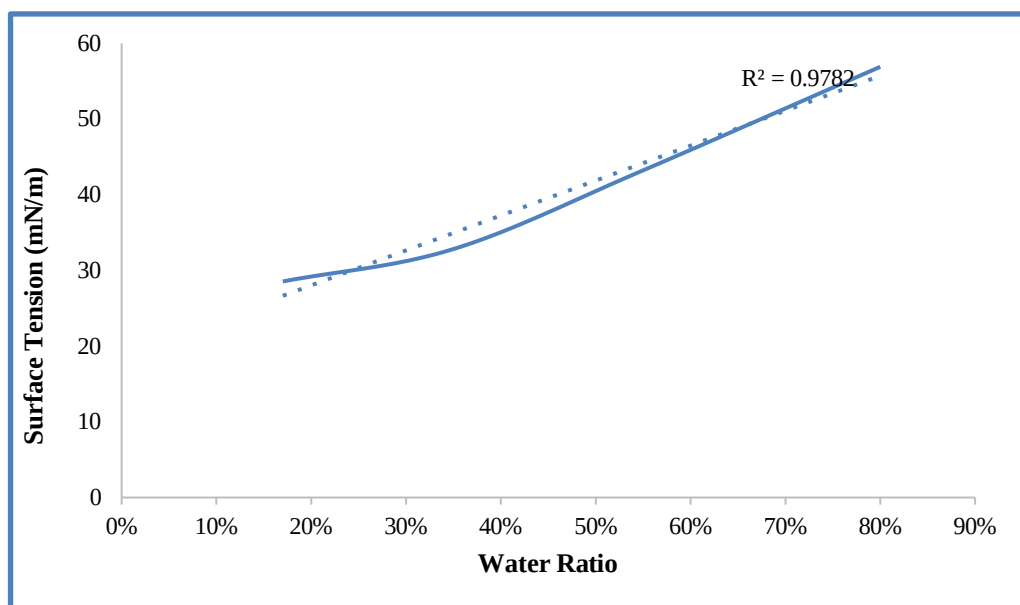


Figure 4-3 Surface tension variation with increasing water ratio in toluene / water interface

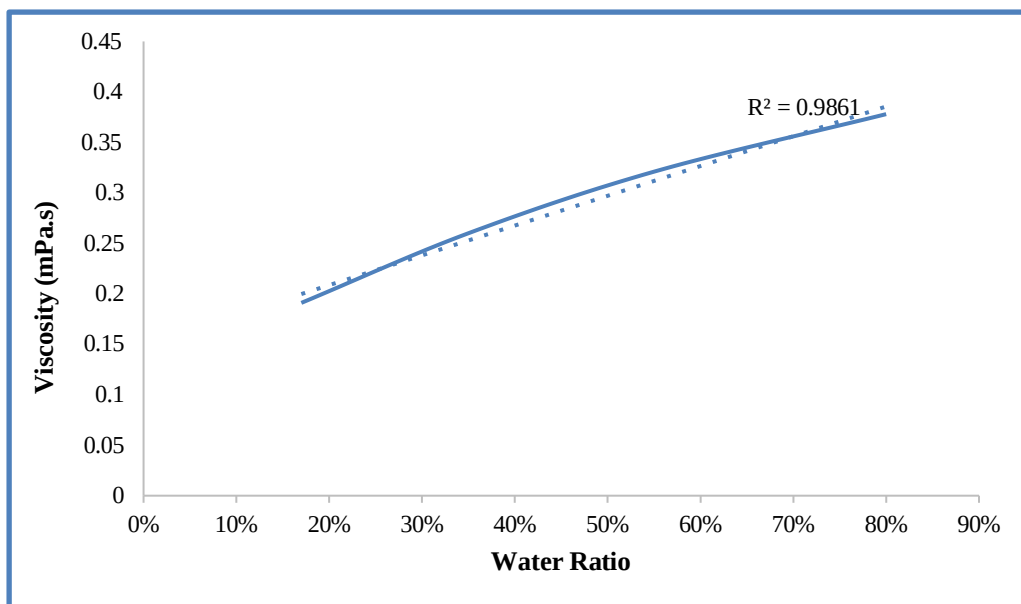


Figure 4-4 viscosity variation with increasing water ratio in toluene / water interface

4-3 Evaluation of Siloxane Copolymer efficiency on D-emulsification of Toluene/water Interface

As presented in **Table 4-4** and **Figure 4-5**, increasing the PDMS-PEG copolymer concentration leads to a significant reduction in surface tension, representing its efficiency in disrupting the toluene/water interface. At low concentrations (7%), the PDMS-PEG copolymer efficiently lowers surface tension to 26.64 mN/m, suggesting rapid adsorption at the interface. As the concentration increases, surface tension continues to decrease reaching a minimum of 6.63 mN/m at 65%. Despite this, the highest DE% is observed at 55%, indicating that beyond this concentration, bulk phase aggregation may limit further destabilization.

On the other hand, **Table 4-4** and **Figure 4-6**, highlight the evaluation of viscosity at the interface. Viscosity decreases continuously with increasing PDMS-PEG copolymer concentration, reflecting enhanced phase separation and reduced interfacial resistance. The lowest viscosity value (0.107 mPa.s) is reached at 65% PDMS-PEG concentration, further supporting the effectiveness of the PDMS-PEG copolymer in destabilizing the toluene/water interface.

The demulsification efficiency (DE%), as summarized in **Table 4-4**, follows a nonlinear tendency, with a peak of 94.93% at 55% PDMS-PEG copolymer. This suggests that at this concentration, the PDMS-PEG copolymer achieves optimal disruption of the interfacial film, allowing coalescence of dispersed droplets and effective phase separation. However, beyond this point, DE% declines slightly to (64.16% at 65%), despite further reductions in surface tension and viscosity. This behavior implies that excessive PDMS-PEG copolymer concentrations may lead to stabilization effects rather than continued destabilization, as excess PDMS-PEG copolymer molecules may aggregate in the bulk phase rather than actively participating at the interface.

Table 4-4 Evaluation of Siloxane Copolymer efficiency on De-emulsification of Toluene/water interface

Ratio of Siloxane Copolymer to Interface	Surface Tension (mN/m)	Viscosity (mPa.s)	DE%
0%	34.45	0.229	
7%	26.64	0.198	70.8
25%	24.4	0.193	60.56
35%	18.75	0.185	73.29
55%	8.53	0.144	94.93
65%	6.63	0.107	64.16

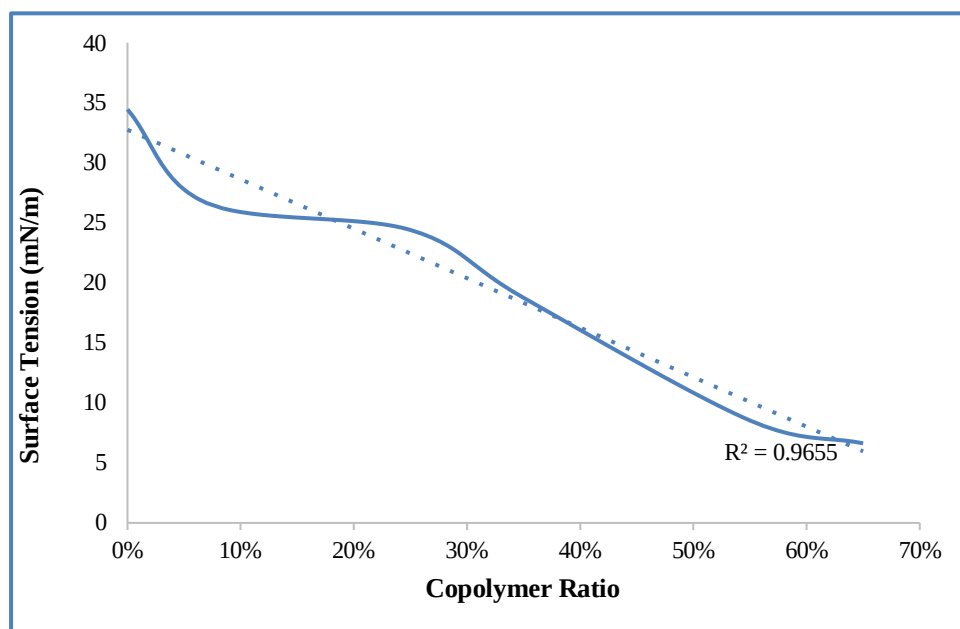


Figure 4-5 Effect of siloxane copolymer ratio on surface tension of Toluene/Water interface

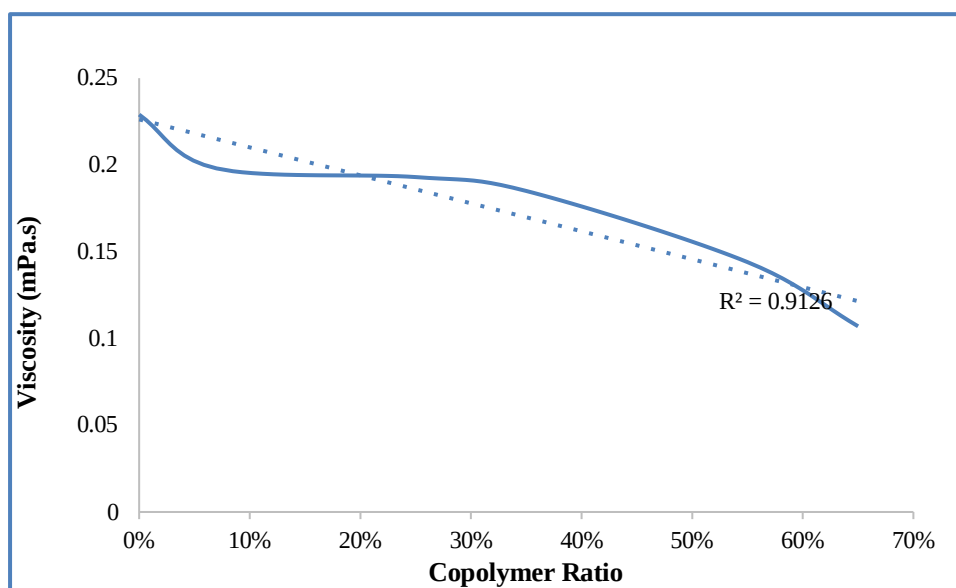


Figure 4-6 Effect of siloxane copolymer ratio on viscosity of Toluene/Water interface

Chapter Five

conclusion and recommendations

5-1 conclusion

This study looked at how polydimethylsiloxane or PDMS membranes work for separating oil and water. The study used experiments and computer simulations to find out. The results showed that PDMS membranes are very good at letting oil pass through while keeping water out.

When the study was done in a lab the membrane worked well. It was able to separate oil and water and it kept working well even when things like temperature and pressure changed. The study also found out that things like how thick the membrane's how big the holes are and what the surface is like can affect how well it works. If the membrane is thin and has the right size holes it works better. If the surface is rough it is better at keeping water out.

The computer simulations gave the results as the lab experiments. They helped us understand how the fluid moves, how the oil and water interact and how the membrane works. The simulations were able to predict what would happen in situations, which makes them useful for designing and improving membranes.

Overall PDMS membranes are a way to separate oil and water without using a lot of energy. They could be used to clean up wastewater, oil spills and industrial waste. PDMS membranes are a solution, for these kinds of problems.

5-2 Recommendations

Membrane Optimization

We need to work on making the membrane structure better. This includes the size of the pores how thick it's what the surface looks like. We want to make the flux better without making the separation worse. We need to do this to make the membrane work well. The membrane structure is very important for this.

Surface Modification Techniques

We can make the membrane better by adding materials like silica nanoparticles or graphene oxide. We can also use treatments on the surface. This will help the membrane longer and not get clogged up.

The membrane will be able to work for a long time if we do this.

Fouling and Durability Studies

We need to do experiments to see how the membrane works with real wastewater. We need to check what happens when it gets clogged up or scaled. We also need to see how it works over a time.

This will help us understand how the membrane works in life.

Advanced Simulation Models

We need to make computer models that can show us how the oil and water interact with the membrane. We can use computer programs to do this.

This will help us understand what is happening with the membrane.

Scale-Up and Industrial Application

We need to do some experiments to see if the PDMS membranes can work in a big operation. We need to check if it's economical and how much energy it uses.

This will help us see if the PDMS membranes can be used in a scale.

Hybrid Systems

We can make the membrane work better by combining it with technologies. This can be things like adsorption or coagulation.

This will help us make a system that works well.

Environmental and Economic Assessment

We need to check if the membrane technology is good for the environment and if it is economical. We need to do an analysis to check this.

The membrane technology should be sustainable and commercially viable. PDMS membranes should be good, for the environment and economical.

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**University of AL-Kitab
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Department**



Quantitative Evaluation of Reservoir Parameters and OOIP Estimation Using Wireline Logs and Structural Contour Maps

A Project Submitted to the College of Engineering
University of AL-Kitab in Partial Fulfillment
of Requirements for the Degree of
B.Sc. in Petroleum Engineering
By:
Safa Mohammed Mahmoud

SUPERVISED BY
Asst. Pro. Dr. Yahya J. Tawfeeq

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ABSTRACT

Accurate estimation of Original Oil in Place (OOIP) is essential for effective reservoir evaluation and field development planning. This study presents an integrated approach combining petrophysical analysis and structural mapping to estimate OOIP using the volumetric method for a tertiary reservoir in an Iraqi field.

Well log data, including gamma ray, resistivity, density, neutron, and sonic logs, were analyzed to determine key reservoir properties such as shale volume, effective porosity, and water saturation. Archie's equation was applied to estimate water saturation using parameters derived from core analysis. Cut-off values for porosity and water saturation were established to differentiate between pay and non-pay zones and to calculate net-to-gross ratios.

Structural contour maps were generated using Surfer software based on well location and depth data, allowing accurate determination of reservoir area and bulk volume. The volumetric method was then applied to estimate OOIP by integrating reservoir geometry with petrophysical parameters.

The results indicate that reservoir properties vary significantly across different units. Units B and BE exhibit the best reservoir characteristics, with higher porosity and lower water saturation, contributing the largest portion of OOIP. In contrast, other units show limited reservoir quality and lower hydrocarbon potential.

The study confirms that the volumetric method is a reliable technique for estimating OOIP during early stages of reservoir development, especially in the absence of production data. However, the accuracy of the results strongly depends on the quality of input parameters. Therefore, integrating dynamic data and advanced modeling techniques is recommended for future studies to improve reserve estimation and reservoir management.

Chapter One

Introduction

1.1 Background of Study

The accurate estimation of original oil in place (OOIP) is a main step in petroleum reservoir evaluation and field development planning. Original oil in place OOIP describes the total volume of hydrocarbons initially present in a reservoir before the beginning of production, serving as the foundation for assessing recoverable reserves, production strategies, and other fundamentals of petroleum fields.

In the traditional way, original oil in place was estimated by core analysis, well testing, and volumetric methods but the evolution of well logging (wireline logs) and geological mapping techniques has significantly improved the precision of subsurface evaluations (Hamd-Allah,2022).

Quantitative evaluation combined geological, petrophysical, and geophysical information to derive essential reservoir parameters such as porosity, permeability, water saturation, and net to gross ratio.

Well logging, consisting of gamma ray, resistivity, density, and neutron logs, which provide continuous in –situ measurements that allows for detailed interpretation for lithology and fluid distribution. These logs are important for identifying hydrocarbon bearing zones and quantifying their petro physical properties.

Combining petrophysical evaluation with structural contour maps that play an important role in defining reservoir geometry and closure, which are essential for calculating reservoir volume, by that research can perform a quantitative

volumetric estimation of OOIP which is both reliable and field specific. There are several methods to estimate original oil in place such as: decline curve analysis, Material balance method, analogy, and volumetric method.

Decline curve analysis methods , in a variety of forms , have been used in the petroleum industry for more than fifty years to analyze production data and forecast reserves ,the term of decline curve analysis refers to the principal products of oil wells or gas wells respectively versus time or versus cumulative production to estimate reserves , new production decline type curves represent an advancement over previous work because a clearer distinction can be made between transient and boundary dominated flow periods (Agarwal, 2015).

The material balance method involves estimating the remaining volume in the reservoir based on changes in the reservoir pressure as volumes are produced from the reservoir. Material balance methods may be used to estimate reserves when there is sufficient reservoir pressure and production data to perform reliable calculations of hydrocarbons initially in place and to determine the probable reservoir drive mechanism. Reliable application of this method requires accurate historical production data for all fluids (oil, gas, and water), accurate historical bottom hole pressure data, and pressure – volume – temperature (PVT) data representative of initial reservoir conditions (petroleum economics).

Analogy and statistical methods are typically used for undrilled prospects, to supplement volumetric methods in a field or reservoir early stages of development and production. in addition, the method may be used to estimate reserves for undrilled tracts in a partially developed field or reservoir.

The methodology assumes that the analogous field, reservoir, or well is comparable to the subject field, reservoir, or well regarding those aspects that control ultimate recovery of oil or gas. The weakness of the method is that this

assumptions validity cannot be determined until the subject field or reservoir has been sustained production.

Volumetric methods are used when subsurface geologic data are sufficient for structural mapping of the objective field or reservoir. one of the objectives of this mapping is to estimate oil and gas initially in place.

The evaluation in this project is based on the volumetric method to estimate the OOIP using structural contour map and wireline logs to give more accurate results. The volumetric method is considered one of the best methods in estimate oil original in place (OOIP) because it is often the only available method during the critical early phases of exploration, before production begins (AbulMajeed,2023).

1.2 Problem Statement

Estimating the original oil in place or OOIP is essential for several reasons. From an economic perspective, it helps in assessing the potential value of a reservoir and making investment decisions, so it gives the answer to the question whether it is economically successful or not. It also guides the design and development of production strategies to maximize recovery. From a petroleum reservoir management perspective, understanding OOIP is key to optimizing the recovery factor, planning secondary and tertiary recovery methods, and it is useful in the prediction of the reservoir's performance over time. From a broader petroleum engineering viewpoint, it helps in resource estimation, reservoir simulation, and planning for enhanced oil recovery techniques. It's the foundation for effective and efficient reservoir management.

The volumetric method is used in estimating original in place because it is based on initial reservoir properties and petro physical properties such as porosity

, permeability , and water saturation which can be determined directly from the well logging data , so basically it provide more accurate results than other methods are used in estimating OOIP , in addition to that the volumetric method for estimating OOIP is generally applied before production starts , once the production begins , the reservoir conditions change , and other methods are used such as material balance or history matching , are used to update the estimates.

There are parameters are used in the volumetric equation such as reservoir bulk volume (B_v) which composed of reservoir area (A), thickness (h), in addition to porosity and water saturation.

Porosity is a measure of the amount of internal space that can hold fluids. Porosity is determined by using wireline or well logging, specifically by density, neutron, and Gamma ray.

Water saturation is defined as fraction, or percent, of the pore volume occupied by a particular fluid (oil, water, gas) in this saturation is occupied by water, water saturation is measured by wireline through the resistivity log and then correcting it by using Archie's equation.

In this project, the reservoir bulk volume is determined by the structural contour map, and for porosity and water saturation data will be taken from well logging measurements.

Well logging is the technique of making petrophysical measurements in the sub-surface earth formations through the drilled borehole to determine both the physical and chemical properties of rocks and the fluid they contain. Resistivity log measures the ability of rocks to conduct electrical current and are scaled.

There are three types of well logging to determine the porosity; Sonic log; Density log and Neutron log. Sonic log a log that measures interval transit time (Δt) of a compressional sound wave travelling through the formation along the axis of the borehole. Neutron logs measure the hydrogen content in a formation, in

clean , shale free formation , where the porosity is filled with water or oil , the neutron log measures liquid filled porosity (ϕ_N , $PHIN$, $NPHI$). Each of these log measures different physical properties of the formation , by integrating their data , a more accurate and reliable porosity estimation can be achieved.

In calculating original oil in place (OOIP) we must know these petro physical properties: Porosity, since the original place in place is placed through a formation, we must take the average porosity of the whole formation (by wire line). Water saturation, each layer has a differ porous medium so that an average water saturation is also taken (by wireline)

It is significant to announce that traditional methods to estimate reservoir area from contour map Planimeter meter which is a mechanical instrument used to measure area of an arbitrary two dimensional shape , typically on a map or diagram to digitize contour line , we will regenerate structural contour map for one iraqi field using a modern software depending on wells location to estimate reservoir area , then calculating bulk volume .

1.3 Objective of the Study

The objectives of this work are listed below:

- 1) To determine essential petrophysical parameters such as porosity, permeability, water saturation, and net pay thickness.
- 2) To generate structural contour maps of the reservoir tops using well data and depth structure information.
- 3) To integrate petrophysical and structural data for volumetric estimation of original oil in place (OOIP)

Chapter Two

Theoretical Background

2.1 Introduction

This chapter will be handling the theoretical and the equations that will be used in the quantitative evaluation of the reservoir and estimate the original oil in place (OOIP) , estimating oil in place quantitatively with wireline logs and structural using volumetric method , by this formula $[7758 \times A \times h \times \phi \times (1 - S_w)]$, where area(A) comes from structural maps , net pay thickness (h) also from the structural contour map , and porosity (ϕ) and water saturation (S_w) are derived from log analysis using gamma ray , density , neutron , and resistivity .

This integrates geological structure (maps) with petrophysical properties (logs) to calculate the volume of hydrocarbon – bearing rock, defining net pay with permeability or porosity cutoffs, ultimately providing an important first step in reservoir evaluation

2.2 Theoretical Basis

In Volumetric method, the core principle is to calculate the volume of the reservoir and multiply it by the fraction of the volume occupied by oil. Structural contour maps define the area (A) and net pay thickness (h). They use data and seismic interpretations to map the reservoir's top and bottom boundaries, showing structural heights (traps) and defining the spatial extent of the oil accumulation. Wireline logs (petrophysical data), logs (Gamma ray, Resistivity, Density, Neutron) provide data key parameters.

Those parameters are porosity(ϕ), from density/neutron logs, showing pore space. water saturation (S_w), from resistivity logs (Archie's equation), indicating the percentage of pore space filled with water. Shale content, from Gamma Ray

logs, helping define the rock type. Net pay determination, a permeability cutoff (from core data if available) or from a related porosity cutoff is applied to log – derived data to identify zones that can produce oil, except for non- reservoir rock. Fluid properties, the oil formation volume factor (B_o) corrects the oil volume from surface conditions to reservoir conditions (barrels per stock tank barrel)

2.3 Wireline Logs and Reservoir Parameters

Wireline logs are used to measure the petrophysical properties of the reservoir, which include, porosity and water saturation. These wireline logs are Gamma ray, Resistivity, Density, Neutron, Sonic logs. Gamma ray logs measure the natural radioactivity of formations penetrated by the wellbore; it is used to differentiate between shales (clays) and clean reservoir rocks such as sandstone, limestone, and dolomite. They contain low gamma ray values.

Resistivity log measures the ability of the formation to resist the flow of electrical current, it is considered one of the most logs because it determines hydrocarbon saturation, water saturation (S_w), reservoir quality, and fluid type. Resistivity logs serve as: Fluid type identification, resistivity strongly distinguishes between hydrocarbons (high resistivity), non-conductive. Saline formation water (low resistivity), conductive.

There are types of resistivity logs, conventional electrical surveys (ES), Focusing electrode logs, micro-resistivity logs, induction logs. The reading we are taking is the true resistivity.

Water saturation (S_w) calculation, using Archie's equation. Formation evaluation includes detect pay zones, identify permeable intervals, and estimate hydrocarbon saturation. Differentiating formation zones, resistivity logs help identify flushed zone (R_{XO}), transition zone, un-invaded zone (R_t).

Density logs by emitting gamma rays from radioactive source (usually cesium-137) into the formation, these gamma rays interact with the electrons in the formation through Compton scattering, and the detector measures the returning (scattered) radiation. Neutron log is a logging tool that is primarily designed to estimate formation porosity by measuring the hydrogen content in the rock. Sonic log, also referred to as an acoustic log or DT log, used to measure the speed of sound waves as it travels through subsurface.

Density, neutron, and sonic logs are all common logs to measure porosity. Density and porosity, the porosity is measured by density log by comparing bulk density and fluid type.

$$\varphi_D = \frac{\rho_m - \rho_b}{\rho_m - \rho_f} \quad (1)$$

Where:

φ_D = density porosity.

ρ_m : matrix density (gm/cc).

ρ_b : bulk density (gm/cc).

ρ_f : fluid density(gm/cc).

A gamma ray source (often Cesium-137) and detectors that measure the intensity of backscattered gamma rays, gamma rays interact with electrons in the formation, the amount of scattering and absorption depends on electron density which is directly related to bulk density (Krygowski, 2004).

Neutron and porosity, high hydrogen content means high porosity. The tool emits high – energy neutrons from a chemical source (commonly Americium-Beryllium,Am-Be), these fast neutrons collide with atoms in the formation , the greatest slowing – down effect occurs when neutrons hit hydrogen atoms because has a mass similar to neutrons, the tool measures the number of slowed (thermal)

neutrons or capture gamma rays returning to it is detectors, the count is then converted to neutron porosity (ϕ_N)(Donaldson, 2016).

Sonic and porosity , the tool contains a transmitter that emits high-frequency acoustic waves, these waves travel through the formation and are picked up by one or more receivers spaced along the tool , the log records the travel time of the sound waves , expressed as Δt (delta-t) in microseconds per foot ($\mu\text{s}/\text{ft}$).

$$\Delta t = \frac{\text{travel time}}{\text{distance}} \quad (2)$$

Low travel time (high velocity), high velocity (usually lower porosity).

Porosity can be estimated using Wyllie time- average equation:

$$\varphi = \frac{\Delta t_{\log} - \Delta t_{\text{matrix}}}{\Delta t_{\text{fluid}} - \Delta t_{\text{matrix}}} \quad (3)$$

typical matrix Δt values: sandstone: $\sim 55 \mu\text{s}/\text{ft}$; limestone: $\sim 47 \mu\text{s}/\text{ft}$ and dolomite: $\sim 43.5 \mu\text{s}/\text{ft}$.

The porosity that is used is the effective porosity because it represents the pore volume that is occupied by hydrocarbons.

Net pay, net pay is a key parameter in reservoir evaluation. It identifies penetrated geological sections that have sufficient reservoir quality and interstitial hydrocarbon volume to function as producing interval. The total thickness of an evaluation interval, either along whole or in true vertical space, is termed “gross thickness”. the term “net thickness” indicates that some of the gross thickness has been removed. There are three types of net thickness: net sand, net reservoir, and net pay. Net pay is subinterval of net reservoir, which is in turn, a subinterval of net sand (Selley, 1998). To determine net pay, log data is evaluated using several cutoff parameters, the most common shale volume cutoff (V_{sh} cutoff). Shale volume (V_{sh}) determination, shale volume is usually estimated from Gamma Ray

log (GR), spectral GR, neutron-density separation, resistivity-porosity crossplot.
Standard GR – based equation:

$$V_{sh} = \frac{GR_{log} - GR_{max}}{GR_{max} - GR_{min}} \quad (4)$$

Where:

Vsh: volume of shale (or clay).

GRlog: gamma ray reading from the log

GRmax: maximum gamma ray value.

GRmin: minimum gamma ray value.

And then we make a correction to the previous equation:

$$V_{sh} = 0.083(2^{3.7GR} - 1) \quad (5)$$

Hydrocarbon saturation, hydrocarbon saturation is not directly measured; it is determined by estimating porosity (ϕ) using density, neutron, sonic. Calculating water saturation (S_w) by using Archie's equation which is considered as a fundamental empirical relationship used in Petrophysics to estimate water saturation (S_w) in clean (clay-free) reservoir rocks, mainly sandstone.

$$S_w^n = \frac{a \cdot R_w}{\phi^m \cdot R_t} \quad (6)$$

Where:

Rt: formation true resistivity (ohm.m)

Rw: formation water resistivity (ohm.m)

ϕ : porosity.

a,m,n: Archie constants.

2.4 Structural Contour Maps

Structural contour maps are subsurface geological maps that show the elevation or depth of a specific geological horizon, such as the top of a reservoir, a formation boundary, or a fault surface. The elevations are represented by contour lines, each connecting points of equal depth below sea level (or sometimes height above sea level) (Bjorlykke,2015).

Structural maps help in visualizing subsurface geometry (anticlines, synclines, domes, basins, faults), also identify structural traps, determine depth to reservoir zones, and the most important is to estimate reservoir volume when integrated with petrophysical data and isopach maps (Boggs, 2014).

The creation of structural contour maps, structural contour maps are usually built by, picking formation tops from well logs (gamma ray, resistivity, density, sonic), converting well depth to subsea elevation (SS), interpolating between wells using geological knowledge, incorporating seismic interpretation when available (Bischke,1991).

Structural contour maps provide important subsurface understanding needed for reservoir characterization, hydrocarbon trap delineation, original oil in place and original gas in place, well placement and field development planning (Coruh,1988).

The volumetric method uses subsurface structural contour maps and isopachous maps. A subsurface contour map shows lines connecting points of equal elevations on the top of a bed and therefore shows geologic structure, a net isopachous map shows lines connecting points of equal net formation thickness, the individual lines connecting points of equal thickness called isopach lines. The oil-water, gas-water, or gas-oil contact line is the zero isopach line.

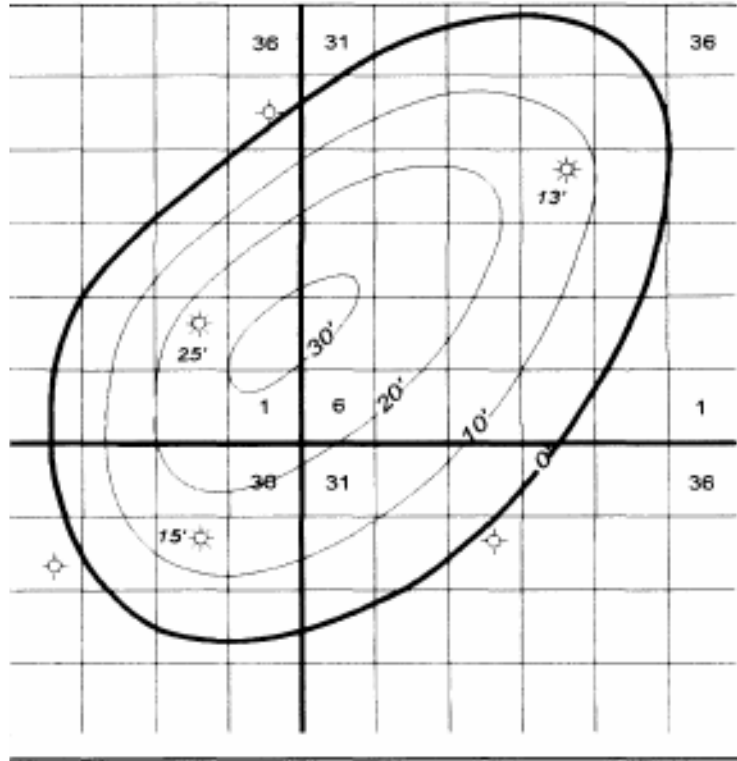


Fig (2.1) structural contour map

The volume is obtained by planimetering the areas between the isopach lines of the entire reservoir. Planimeter tool is a mechanical tool used to measure surface area of the maps , computer software , such as Didger/ Neura-Map, used to digitize surface area of map.

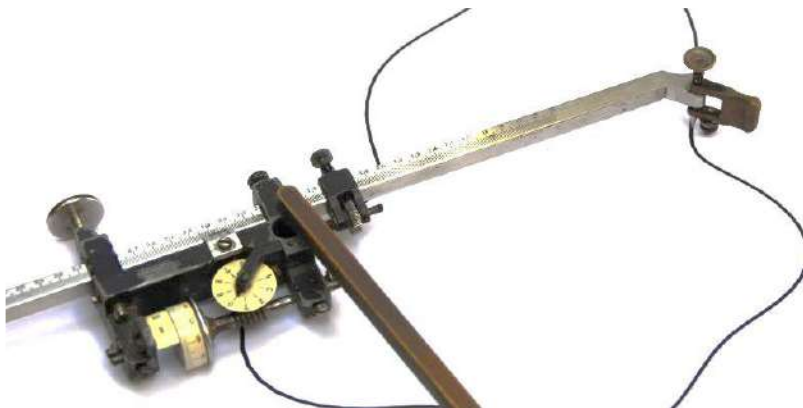


Fig (2.2) Planimeter tool.

Two equations are commonly used to determine the approximate volume of the reservoir from the Planimeter readings, which are Pyramid method and Trapezoid method.

A) Pyramid method:

$$\Delta V_b = \frac{h}{3} (A_n + A_{n+1} + \sqrt{A_n A_{n+1}}) \quad (7)$$

Where:

ΔV_b : bulk volume in acre-ft.

A_n : is the area enclosed by the lower isopach line in acres.

A_{n+1} : is the area enclosed by the upper isopach line in acres.

h : is the interval between the isopach lines in feet.

B) Trapezoid method:

$$\Delta V_b = \frac{h}{2} (A_n + A_{n+1}) \quad (8)$$

Where:

ΔV_b : bulk volume in acre-ft.

A_n : the area enclosed by the lower isopach line (acres).

A_{n+1} : the area enclosed by the upper isopach line (acres).

For the best accuracy, the Pyramidal formula should be used because of its simpler form, however, the trapezoidal formula is commonly used, but it introduces error of 2% when the ratio of successive areas is 0.5. Therefore, a commonly adopted rule in unitization programs is that;

- Whenever the ratio of the areas of any two successive isopach lines is smaller than 0.5, the pyramidal formula is applied.
- Also, whenever the ratio of the areas of any two successive isopach lines is found to be greater than 0.5, the trapezoidal formula is applied.

In this project, the contour maps that will be used by a software computer, so it will be more developed than the traditional way. The area of the reservoir and net thickness are determined from the structural contour map; input data will process in the program and results will be shown on the structural contour maps. Structural contour maps are very important in determining the reservoir volume (North,1985).

2.5 Original Oil in Place Estimation

The volumetric method for estimating original oil in place (OOIP) is a fundamental reservoir engineering approach that quantifies the total volume of hydrocarbons initially present in a reservoir before production (Dake,1983).

This method integrates geological and petrophysical parameters by calculating the product of the reservoir's bulk rock volume, average porosity, average water saturation (Hawkins,1991).

The volumetric method is widely applied during early field appraisal due it's reliance on static data and its ability to yield reasonable estimates prior to acquiring production performance information. The equation of original oil in place in volumetric method:

$$OOIP = 7758 \times A \times h \times \phi \times (1 - S_w) \quad (9)$$

Where:

A: area of the reservoir, ft².

h: net thickness, ft.

ϕ : porosity, dimensionless.

S_w: water saturation.

Chapter Three

Methodology: Well Log Analysis and Map Construction

3.1 Well Log Interpretation

Well log interpretation is one of most important parts in well log operation. Geologists, engineers and log analysts use logs to determine the necessary information to perform their tasks. Available log data in reservoir engineering is used in engineering calculation, especially in reserve estimation. The most important use, however, determines initial oil in place and detection of the potential of hydrocarbon bearing zones. There are several techniques that can be used to identify hydrocarbon bearing zones and to determine their petrophysical properties and fluid analyses. The best interpretation technique for any interesting formation depends on the quality and the quantity of available log data for analysts and type of problem.

In this study, twelve wells were selected to construct contour map for field X to cover the reservoir. Full sets of digitized logs (sonic, neutron-density and resistivity logs) available penetrated tertiary reservoir are used. The digitized logs resampled every 0.15 m. The processes of petrophysical properties interpretation are achieved by using Microsoft Excel package. The interpretation includes the determination of the effective porosity, corrected to shale effects, water saturation and all parameters that are required in the interpretation processes. Only one well named (Kz-2) were used with full set logs for formation evaluation and log interpretation in this study. The reservoir stratigraphy for this well composed of six units (Jerbie, Unit A1, Unit A2, Unit B, Unit BE, Unit E) as shown table (3-1) below.

Table (3-1): Tops of tertiary reservoir unit in field X.

Units	Tops (m)					
	Jeribe	Unit A1	Unit A2	Unit B	Unit BE	Unit E
Top depth	2267.5	2279.5	2291	2326.5	2393	2442.5- 2490

3.2 Determination of Formation Water Resistivity

The DST tests in well (Kz-2) that are conducted in tertiary reservoir provide formation water sample to analysis. From lab report of water samples, the concentration of salt equivalent to NaCl in well Kz-2 was 142160 ppm ether in well Kz-3 was 142470 , so the average value was 142315 ppm this value was determined R_w at temperature equal to 75°F by equation (3-1) which gives the value of R_w about 0.056 ohm.m . Then R_w for each well determined according to bottom hole temperature by using equation (3-1).

$$R_{w75} = \frac{1}{2.74 \times 10^{-4} \times CSP^{0.955}} + 0.0123 \quad (3-1)$$

$$R_{w@ft} = R_{w75} \frac{81.77}{ft + 6.77} \quad (3-2)$$

Where;

R_{w75} : Formation water resistivity at 75°F.

$R_{w@ft}$: Formation water resistivity at formation temperature °F.

CSP: NaCl concentration in ppm .

Ppm: part per million.

Rmf values taken from well logs header reports and corrected to bottom hole temperature by using equation (3-1) and listed with R_w values in table (3-2).

Table (3-2): Formation water saturation (RW) and mud filtrate (Rmf) for selected wells

Well no.	FT	$R_{w@FT}$	$R_{mf@FT}$
Kz-2	180	0.025	0.243

3.3 Shale Volume Determination

The GR log is a measurement of the natural radioactivity of the formation. In sedimentary formations, the log normally reflects the clay content of the formation because the radioactive elements tend to concentrate in clays. Clean formations usually have a very low level of radioactivity, unless a radioactive contaminant such as volcanic ash or granite wash is present or formation waters contain dissolved radioactive salts (*Dawin V.Ellis, 2008*).

Calculation of gamma ray index is the first step needed to determine the volume of clay from gamma ray log(*Schlumberger, 1974*):

$$IGR = \frac{GR_{log} - GR_{min}}{GR_{max} - GR_{min}} \quad (3-3)$$

The calculated GRI is then used on the appropriated chart or determined mathematically (Vsh) using the following equation for Tertiary rocks according to *Dresser Atlas, 1979 (Irfan, 2008)*;

$$Vsh = 0.083(2^{(3.7*IGR)} - 1) \quad (3-4)$$

Where;

IGR: Gamma ray index

GR log: Gamma ray reading in interest interval, API.

GR min: Gamma ray reading in cleanest interval, API.

GR max: Gamma ray reading in shale interval, API.

The results of mathematical averaging calculated clay volume are listed in table (3.3). It can be seen from table (3.3) that the clay volume varies from unit to other, where the maximum clay volume is observed in units (A1) while minimum clay volume is observed in units (B) and (BE).

Table (3.3): Average Vsh values for each formation (as fraction).

Units	Depth (m)	Shale Volume
Jerbie	2267.5	0.121
A1	2279.5	0.251
A2	2291	0.201
B	2326.5	0.086
BE	2393	0.085
E	2442.5	0.122

3.4 Porosity Estimation

The porosity of a zone can be estimated either from a single “porosity log” (sonic, density, or neutron log) or a combination of porosity logs, in order to correct for variable lithology effects in complex reservoirs. In the carbonates, mineral mixtures are primarily drawn from calcite, dolomite, and quartz; anhydrite and gypsum may also occur (*Schlumberger, 2005*). Porosity logs include:

3.4.1 Sonic Log

Sonic log is a porosity log that measures interval transit time Δt of a compressional sound wave traveling through one foot of a formation (*Pirson, S.J., 1963*).

The interval transit time (Δt) is dependent upon both lithology and porosity; therefore a formation matrix interval transit time must be known to derive sonic porosity by *Wyllie Time-Average* equation according to *wylie et.al, 1958* (*Asquith and Krygowski, 2004*).

$$\phi_s = \frac{\Delta t_{\log} - \Delta t_{ma}}{\Delta t_{fl} - \Delta t_{ma}} \quad (3.5)$$

Where;

ϕ_s = Sonic (acoustic) porosity = primary porosity

$\Delta t_{\log}$ = Sonic travel time from the log.

Δt_{ma} = Matrix travel time [whose value is 47.6 ($\mu\text{sec}/\text{ft}$) for limestone and 43.5 ($\mu\text{sec}/\text{ft}$) for dolomite].

Δt_{fl} = is the interval transit time in the fluid within the formation [For freshwater mud = 189 ($\mu\text{sec}/\text{ft}$) and for salt-water mud = 185($\mu\text{sec}/\text{ft}$)].

3.4.2 Density Log

The density log is a continuous record of formations bulk density. This is the overall density of a rock including solid matrix and the fluid enclosed in the pore. Density is measured in gm/cm^3 or (kg/m^3) (*Rider, 1996*).

Two separate density values are used by density log; the *bulk density* (ρ_b or RHOB) and *matrix density* (ρ_{ma}) as measured by logging tool. The bulk density is the density value of the entire formation (solid and fluid part) (*Asquith and Krygowski, 2004*).

To determine density porosity, either by chart or by calculation, the matrix density, type of fluid in the formation must be known (*Asquith and Krygowski, 2004*).

$$\varphi_D = \frac{\rho_{ma} - \rho_b}{\rho_{ma} - \rho_f} \quad (3.6)$$

Where;

ρ_{ma} = matrix (or grain) density.

ρ_b = Bulk density as measured by the tool.

ρ_f = Fluid density (derived from pressure test). Field water density of 1.02 g/cc and gas density of 0.2 g/cc. (For freshwater mud, $\rho_f = 1.0 \text{ g}/\text{cm}^3$, Salt water mud, $\rho_f = 1.1 \text{ g}/\text{cm}^3$).

According to Dresser Atlas 1979, density porosity in a shaly formation is calculated using the following equation:

$$\varphi_{Dcorr} = \frac{\rho_{ma} - \rho_b}{\rho_{ma} - \rho_f} - V_{cl} \left(\frac{\rho_{ma} - \rho_{cl}}{\rho_{ma} - \rho_f} \right) \quad (3.7)$$

Where;

φ_{Dcorr} = Corrected density for clay effect.

V_{cl} = Volume of clay.

ρ_{cl} = Density value of adjacent clay formation.

3.4.3 Neutron Log

Neutron log is a porosity log respond primarily to the amount of hydrogen in the formation. Thus, in clean formations whose pores are filled with water or oil, the neutron log reflects the amount of liquid-filled porosity (*Pirson, S.J., 1963*).

The value of neutron porosity must be corrected in clay formation by the following relation (*Schlumberger, 1972*);

$$\varphi_{Ncorr} = \varphi_{Nlog} - V_{clay} * \varphi_{Nclay} \quad (3.8)$$

Where;

φ_{Ncorr} = Corrected neutron porosity.

φ_{Nlog} = Neutron log reading of the interval.

V_{clay} = Volume of clay. φ_{Nclay} = neutron log of the adjacent clay formation.

Schlumberger (1974) proposed an equation to compute the **total porosity** from neutron and density logs that may be expressed as:

$$\varphi_{ND} = \varphi_t = \frac{\varphi_{Ncorr} + \varphi_{Dcorr}}{2} \quad (3.9)$$

Effective porosity is the total porosity less than the fraction of the pore space occupied by clay. In very clean sands, total porosity is equal to effective porosity (*Bowen D. G., 2003*).

$$\varphi_e = \varphi_t * (1 - V_{clay}) \quad (3.10)$$

The results of mathematical averaging calculated effective porosity is listed in table (3.4), show the calculated effective porosity.

Table (3.4): Porosity Values for Each Unit (as fraction).

Units	Depth (m)	Avg. PHIE
Jerbie	2267.5	0.064
A1	2279.5	0.043
A2	2291	0.061
B	2326.5	0.137
BE	2393	0.126
E	2442.5	0.060

It can be seen from table (3.4) that the porosity is varied from unit to other, where the maximum effective porosity is observed in unit B and unit BE, and minimum effective porosity is observed in unit A1, E and Jerbie.

Note that; all porosity values listed in the table (3.4) represented average arithmetic porosity every 0.25 m, i.e. ($\varphi = \frac{\sum \varphi}{n}$), n = depth interval every 0.15 m.

3.5 Determination of Archie Parameter (a , m , n)

Application of Archie equations to determine water saturation in carbonate reservoir is a big challenge because effect of its parameters on carbonate attribute. Due to Carbonates rocks heterogenetic, a correct determination of Archie's parameter is needed for their evaluation because the incorrect values of Archie's parameters will cause non-acceptable errors in the magnitude of water saturation and in calculating initial oil in place.

Archie parameters (a, m, n) are empirical constants used to calculate water saturation (Sw) in porous rock. Default values are often (a=1, m=2, n=2), but they vary significantly based on rock texture and wettability.

Tortuosity Factor (a), also known as the lithology coefficient or tortuosity coefficient, relates to the matrix properties. Common Range: Usually assumed to be 1, but often varies from 0.62 to 1.49, particularly in sandstones.

Cementation Exponent (m), Represents how efficiently the pore structure connects, with higher values indicating more tortuous paths or poorer connection. In sandstones typically range between (1.8) to (2), in Carbonates usually higher due to complex pore structures, often around 2 or higher.

Saturation Exponent (n) measures the impact of hydrocarbon saturation on resistivity. As a rule, usually assumes a value of (2), particularly in water-wet reservoirs.

Archie's parameters (a , m , n) also are determined from Special Core Analysis (SCAL) and are essential for evaluating water saturation in reservoir rocks. These parameters are part of Archie's Law, which relates rock resistivity, porosity, and fluid saturation. In SCAL experiments, these parameters are obtained through laboratory measurements on core samples. First, the core is fully saturated with brine, and resistivity is measured to determine the formation factor, which is used to calculate a and m from a log-log relationship with porosity. Then, the core is partially desaturated, and resistivity is measured at different water saturations to determine n from the slope of a log-log plot of resistivity index versus water saturation. Accurate determination of Archie's parameters is critical because small errors in m and n can lead to significant inaccuracies in water saturation estimates and, consequently, in hydrocarbon reserve calculations.

In this study, Archie's parameters (a , m , and n) for tertiary reservoir taken from special core analysis from final well report. Table (3-5) represents the Archie's parameters values for tertiary reservoir.

Table (3-5): Archie parameters values used in this study.

Archie's Constant	a	m	n
	1.07	1.43	1.99

3.6 Water Saturation Determination

Porosity and fluid saturation are among the most important reservoir properties used in the reserve estimation of oil and gas. Because of the heterogeneity of most reservoirs, continuous recording of these properties vs. depth is essential for accurate evaluations. Since a complete coring and core analysis of the entire pay zone is impractical, well logging appears to be the most plausible mean to obtain such information. To achieve this task, different logs including resistivity, acoustic and radioactive logs are recorded in the well and well log interpretation is used to obtain the required properties (*Asquith, G., and Gibson, C., 1982*).

Fluid saturation is estimated from resistivity measurement by the Archie equation which relates the resistivity of the information to the porosity, water saturation, and resistivity of the formation water (*Darwin V. Ellis, Julian M. Singer, 2008*) ;

$$S_w = \left[\frac{aR_w}{\phi^m R_t} \right]^{1/n} \quad (3.11)$$

Where:

S_w = water saturation .

R_w = formation water resistivity, ohm-m .

R_t = formation resistivity, ohm-m ,from deep latrolog dll.

a = tortuosity factor

n = saturation exponent

m = cementation factor =2

It is to be noted that, when Equation (3.11) is used with micro-resistivity logs it gives the value of the aqueous phase saturation in the flushed zone, which is composed mainly of mud filtrate R_{mf} . The resistivity of this zone is usually denoted by R_{xo} and equation (3.12) takes the form:

$$S_{xo} = \left[\frac{aR_{mf}}{\phi^m R_{xo}} \right]^{1/n} \quad (3.12)$$

Where;

S_{xo} = water saturation of the flushed zone

R_{mf} = resistivity of mud filtrate at formation temperature.

R_{xo} = shallow resistivity from Micro spherically focused log (μ SFL).

The saturation in the flushed zone which is obtained from Equation (3.12) can be used to estimate the *residual oil saturation* and the *movable hydrocarbon saturation*.

The residual oil saturation S_{or} , and movable hydrocarbon S_{hr} , is calculated from the following equations:

$$S_{or} = \{\phi * (1 - S_{xo})\} \quad (3.13)$$

$$S_{hr} = \{\phi * (S_{xo} - S_w)\} \quad (3.14)$$

Where,

S_{or} : is the residual oil saturation (fraction); and,

S_{hr} : is the movable hydrocarbon saturation (fraction).

The results of mathematical averaging water saturation are listed in table (3.6) calculated for each unit shows.

Table (3.6): Water Saturation Values for Each Unit (as fraction)

Units	Depth (m)	Avg. Sw
Jerbie	2267.5	0.1290
A1	2279.5	0.1879
A2	2291	0.1328
B	2326.5	0.0106
BE	2393	0.0180
E	2442.5	0.0439

3.7 Net to Gross and Cutoffs

Distinguishing productive zones in a drilled oil well is a very important function for petroleum engineers to determine place where to perforate to produce oil. Traditionally, net pay zones can be determined by applying some sets of cutoffs criteria on petrophysical logs.

Net to Gross ratio representing the portion of reservoir rock which is contribute to production. This ratio is determined by means of cutoffs on the log Curves and then applied to the total thickness of the formation to compute the producible intervals. The cutoff is a threshold value applied to assigned reservoir parameters, to divide the formation into pay and non-pay zones. The core permeability, porosity cross-plots is the usual technique to determine porosity cutoff based on permeability cutoff value (0.1md.). If special core analysis is available, then the relative permeability ratio can identify the saturation cutoff.

Porosity cut off for tertiary reservoir determined by using traditional permeability porosity cross plot, by using common permeability cut off value 0.1md in the cross plot for oil reservoir porosity cutoff identified and its value about 0.5 as shown in the figure (3.1) from available special core analysis relative permeability for four sample used to determine water saturation cut off and the average value of water saturation cut equal 58% as shown in the figure (3.2).

Net to gross calculated for each unit in all selected wells and tabulated in table 3.7.

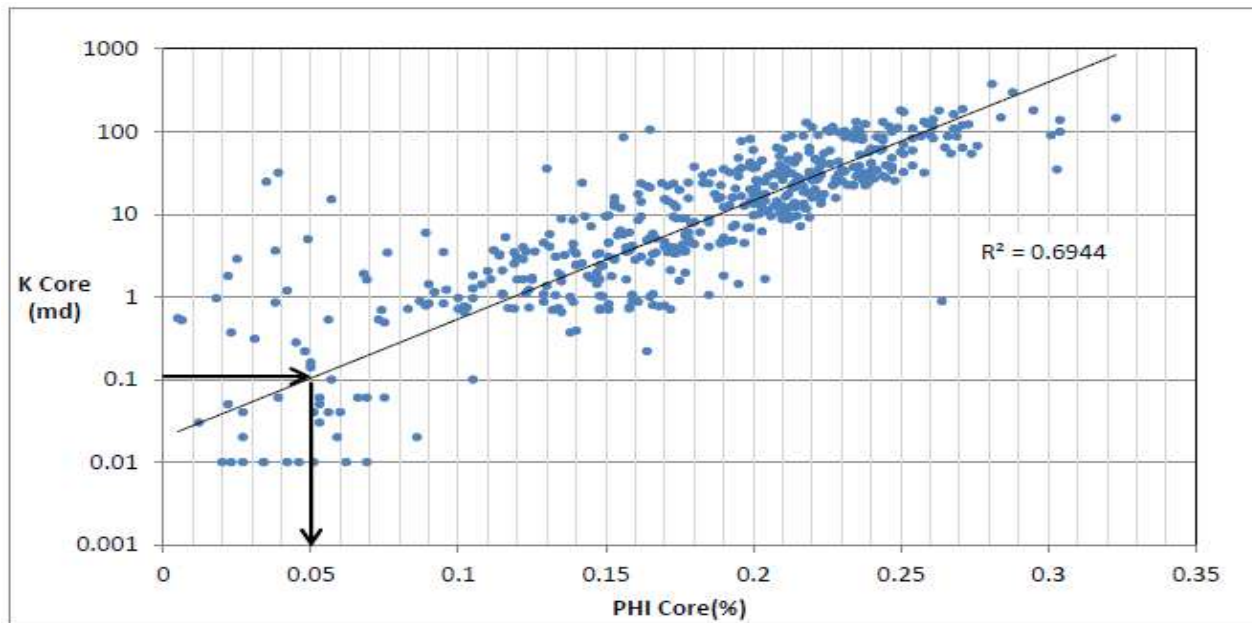


Figure (3.1) Core porosity cut off cross plot

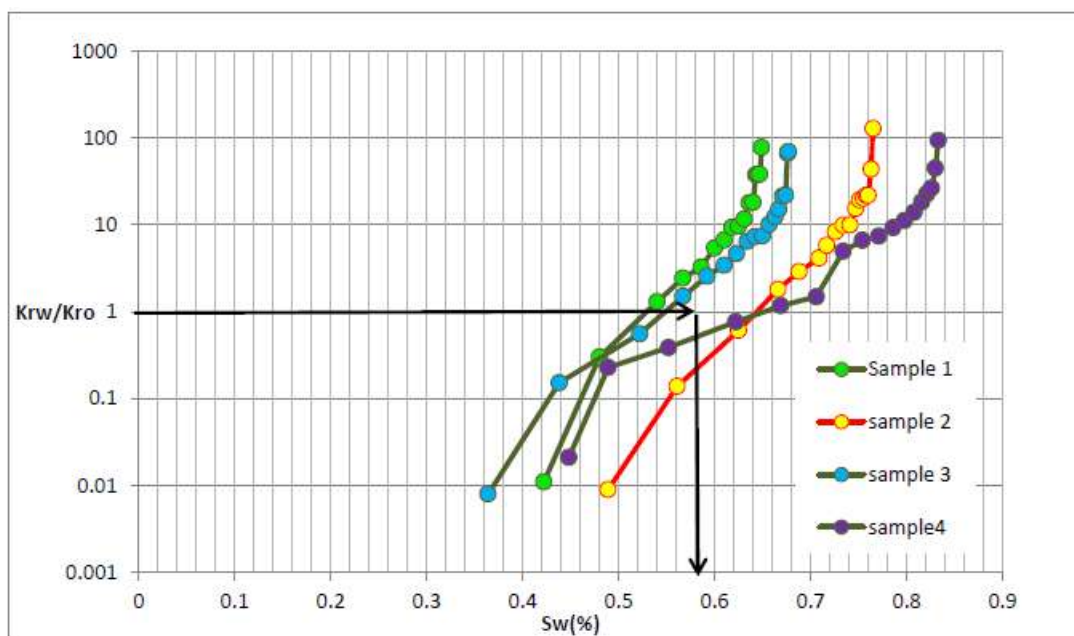


Figure (3.2) Water saturation cut off cross plot

Table (3.7): Net/Gross for tertiary reservoir under study

	Gross thick. m	Net thick. m	N/G
JERIBE	12	0.725	0.0604
Unit A1	12	1.524	0.127
Unit A2	35	11.43	0.3265
Unit B	66.5	23.768	0.3574
Unit BE	49.5	4.2128	0.0851
Unit E	47.5	2.572	0.0541

3.8 Structural Contour Map

Structural contour map represents lines connecting points of equal elevation on a selected geological horizon , it is very important in petroleum Engineering since it is used to identify structural traps , determine well displacement , estimate reservoir closure . And in this study to calculate hydrocarbon volume.

3.8.1 Construction of a Contour Map

The construction of contour map plotted using modern software package called “Surfer”. Surfer is a grid-based mapping program that interpolates irregularly spaced XYZ data into a regularly spaced grid. The grid is used to produce different types of maps including, for example, contour maps and 3D surface maps. Maps can be displayed and enhanced in Surfer, allowing you to produce the map that best represents your data. The most common application of Surfer is to create a grid-based map from an XYZ data file. The Grid | Data command uses a XYZ data file to produce a grid file. The grid file is then used by most of the Map menu commands to produce maps. Post maps and base maps do not use grid files. By these steps a contour map is created using Surfer program, as shown in Figure (3.3). Data used to construct contour maps for area under study are shown table (3.8).

Table (3.8): Field Data used to construct contour map

Well Name	X Easting	Y Northing	Z_TopDepth_m	GOC_m	OWC_m
W-1	422191	3929343	2063	2192	2337
W-2	422645	3930946	2268	2192	2337
W-3	428470	3926929	2230	2181	2326
W-4	417650	3932200	2235	2174	2319
W-9	419060	3931271	2184	2181	2326
W-14	424685	3927939	2101	2172	2317
W-15	421753	3927294	2162	2167	2312
W-16	423851	3929471	2145	2180	2325
W-18	427010	3926362	2201	2181	2326
W-20	424670	3929562	2227	2179	2324
W-25	417660	3931024	2212	2178	2323
W-34	417840	3931632	2220	2175	2320

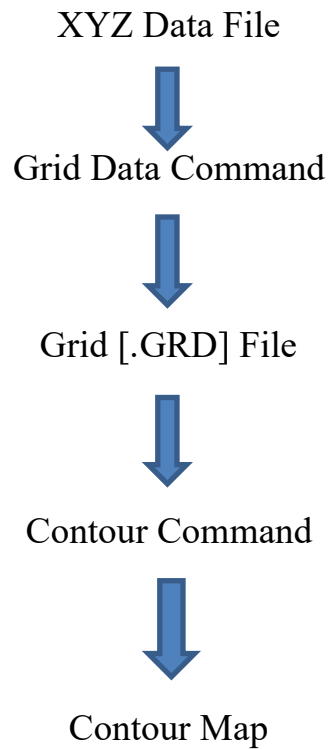


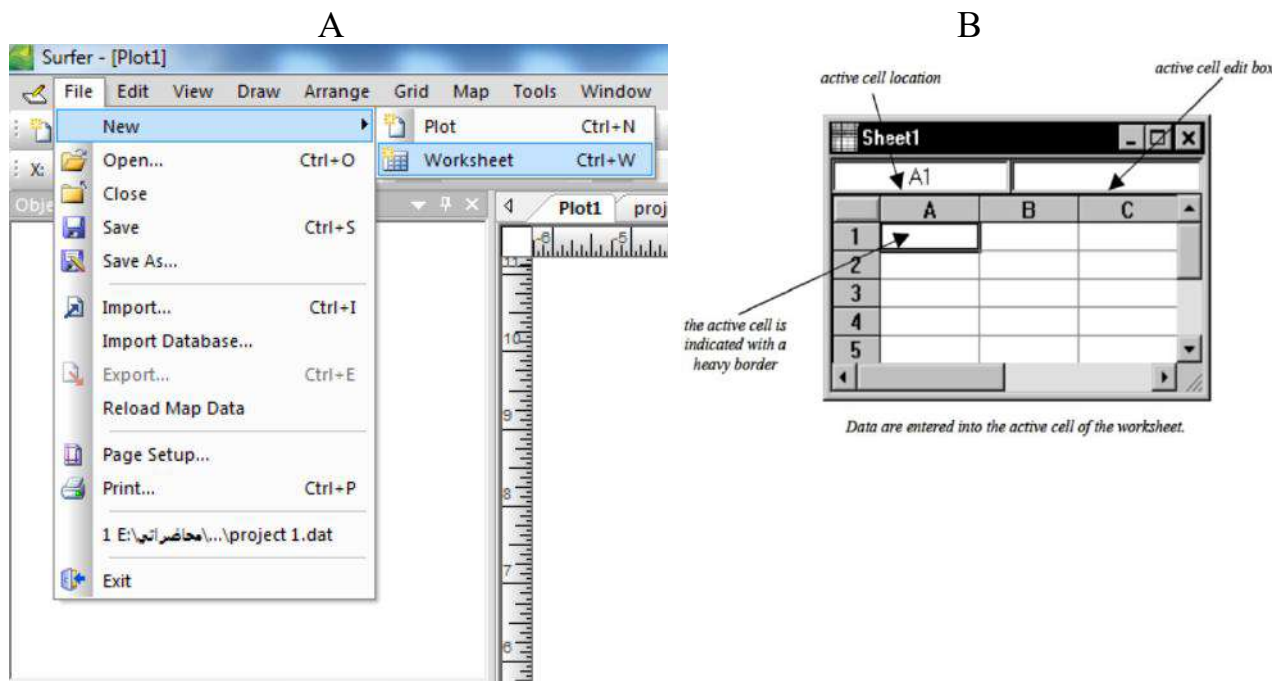
Figure (3.3) Contour map plotting main steps in Surfer

3.8.2 Creating an XYZ Data File

An XYZ data file is three columns of data values, X coordinate represents Easting in Column A, Y coordinate represents Northing in Column B and Z value (Elevation) is in Column C.

The following steps are used to create an XYZ data file in Surfer 13 software, Figure (3.4);

1. Choose the *File | New command*, (step A).
2. Click the Worksheet option in the *New* dialog to display a new empty worksheet window (step B and C).
3. Click the *File | Save* command. The Save As dialog is displayed, (step D).
4. In the Save as type list, choose the *DAT Data (*.dat)* option, (step D).
5. Type the name of the file into the File name box.
6. Click the Save button and the Data Export Options dialog opens.
7. Accept the defaults in the Data Export Options dialog by clicking OK.



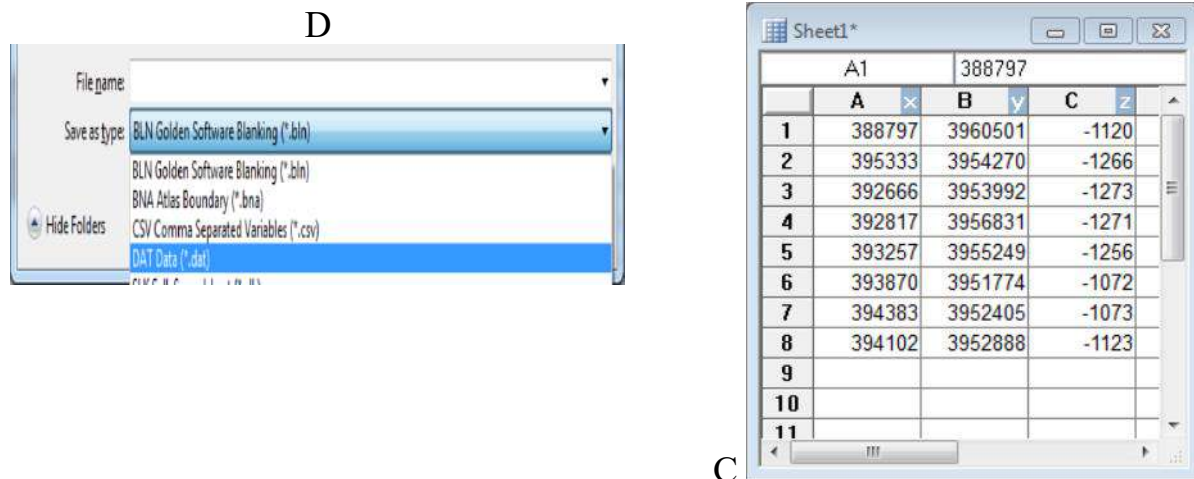


Figure (3.4): Steps of creating XYZ Data File.

3.8.3 Creating a Grid File

The following steps are used to create a Grid File in Surfer 13 software, Figure (3.5);

1. Click on the *Plot* tab, (step A).
2. Choose the *Grid | Data* command, (step A).
3. In the Open Data dialog, click the file *project1.DAT*. Click *Open*, (step B).
4. The *Grid Data* dialog is displayed. The Grid Data dialog allows you to control the gridding parameters. Click *Ok*, (step C).
5. Click *OK* in the grid file has been created message box.
6. If Grid Report is checked, close this report.

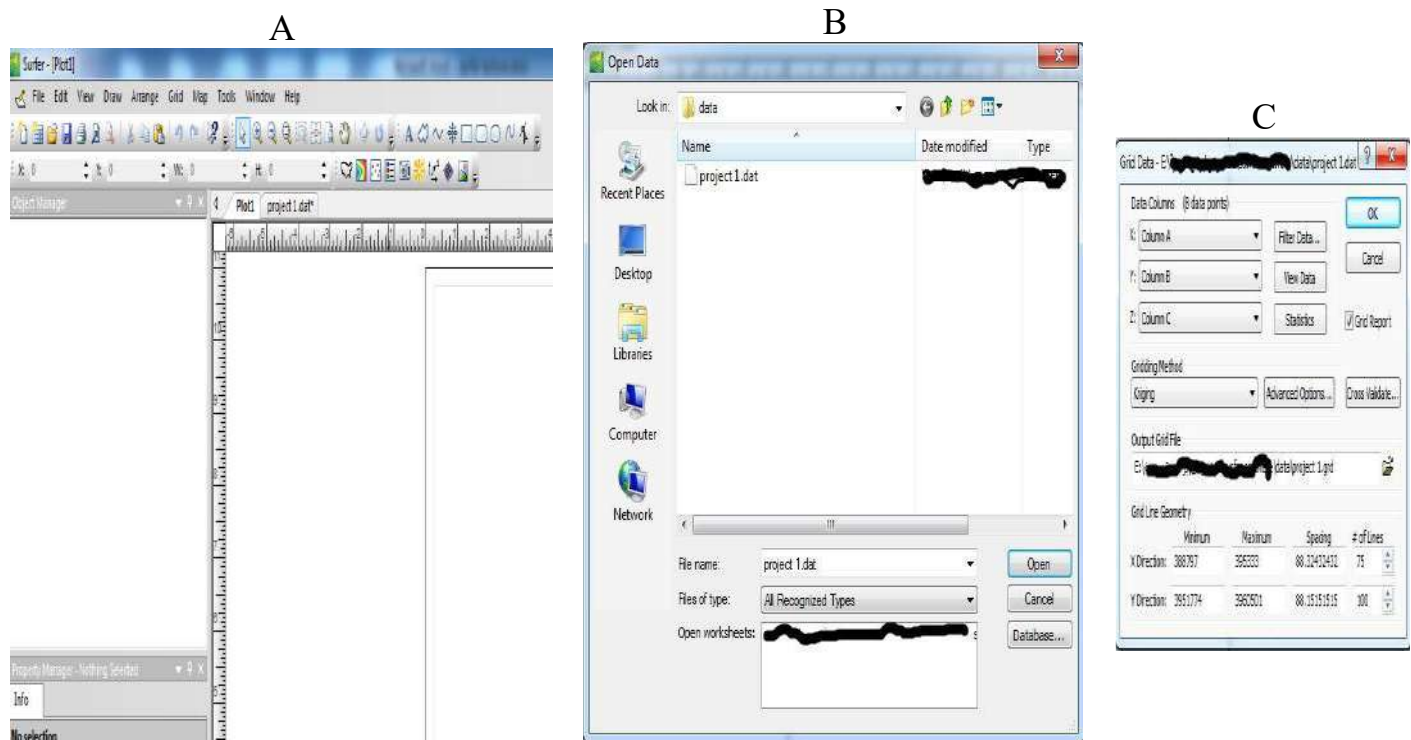


Figure (3.5) Creating a Grid File.

3.8.4 Creating a Contour Map

The following steps are used to create a Grid File in Surfer 13 software, Figure (3.6);

1. Choose the *Map | New | Contour Map* command, (step A).
2. The Open Grid dialog is displayed. The grid file you just created, (project1.GRD) should appear in the File name box, (step B).
3. Click the Open button to create a contour map.
4. The map is created using the default contour map properties.
5. If you want the contour map to fill the window, choose the *View | Fit to Window* command.

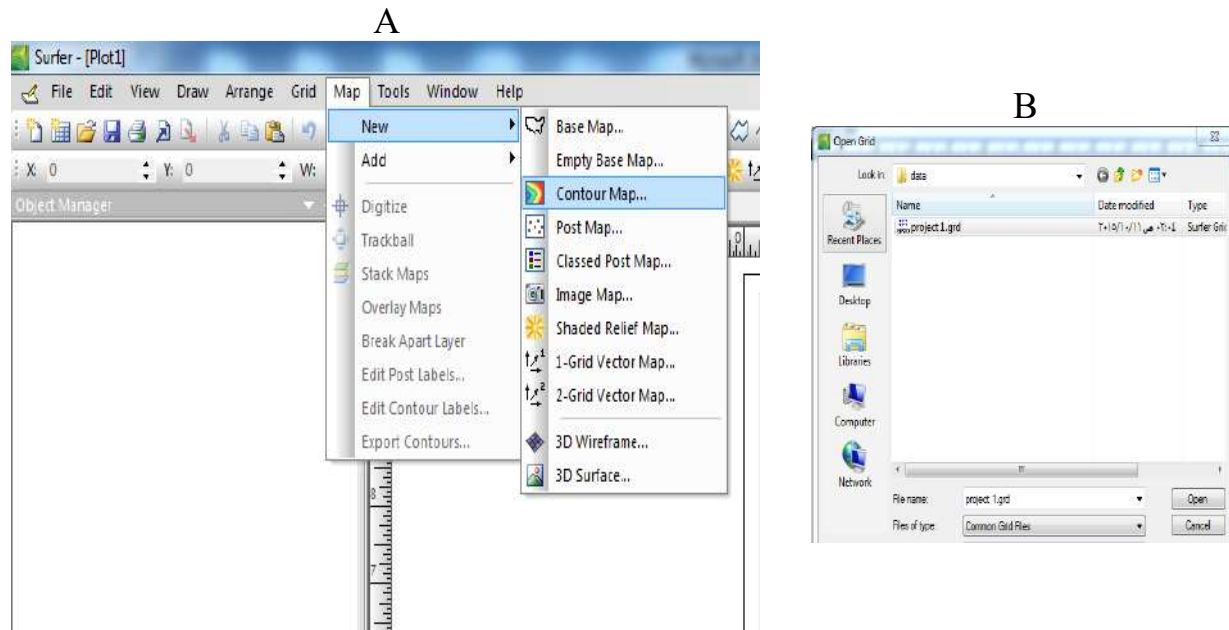


Figure (3.6) creating a contour map.

3.8.5 Changing the Map Properties

After creating a map, you can change the map properties. There are several ways to open an object's properties. The most common method is to double-click on the object.

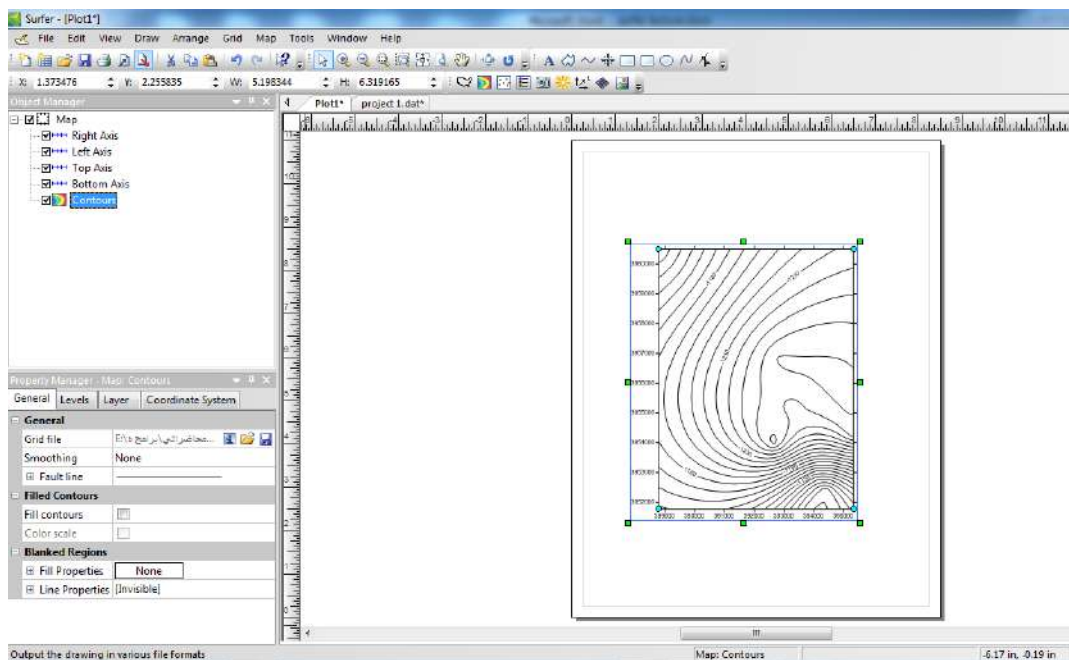


Figure (3.7): surfer window

Changing Contour Levels

1. Click on the Contours object in the Object Manager. The contour properties are displayed in the Property Manager.
2. In the Property Manager, click the Levels tab to display the contour levels and contour line properties for the map.

Changing Contour Fill Properties

1. Click on the General tab in the Property Manager.
2. Check the box Fill contours. The contour map automatically updates to display the default gray scale color fill between contours.
3. Click on the Levels tab. Click Fill colors. Click one of the preset color maps, and the map automatically updates to display the new colors.

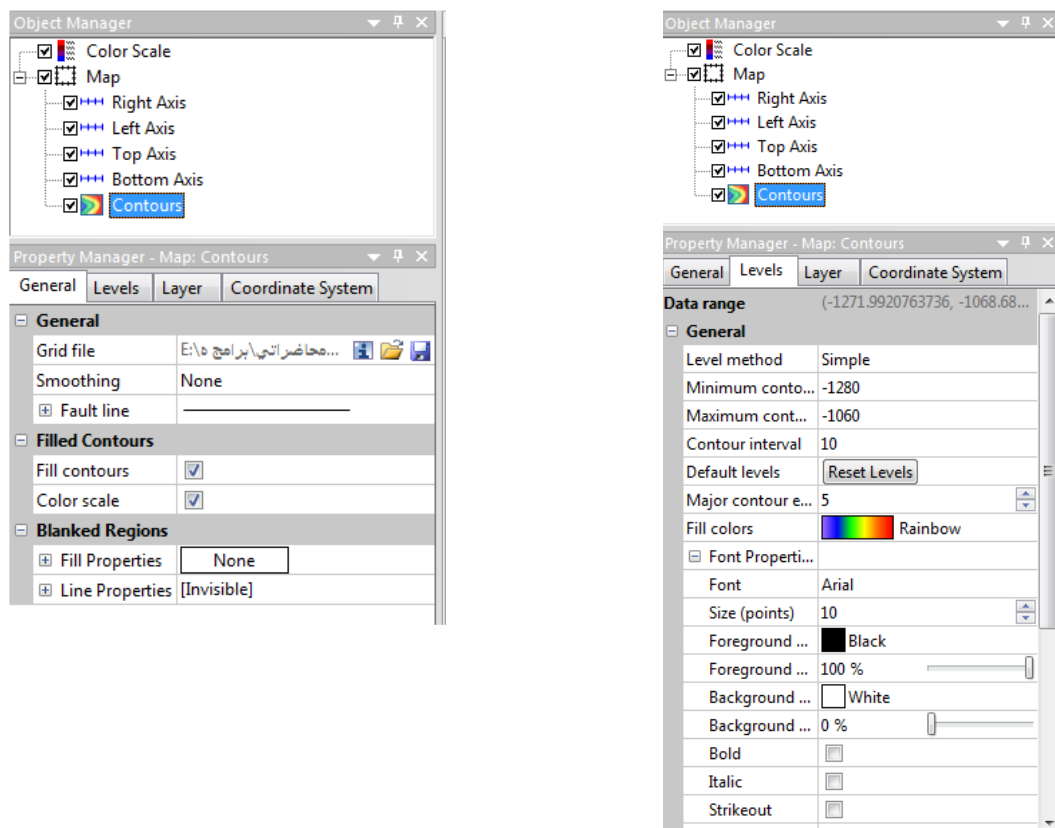


Figure (3.8): changing contour fill properties

3.8.6 Adding, Deleting and Moving Contour Labels

1. Right-click on the contour map and select Edit Contour Labels. Or from *Map | Edit Contour Labels* command. The cursor changes to a black arrowhead to indicate that you are in edit mode.
2. To delete a label, click on the label and press the DELETE key on the keyboard.
3. To add a label, press and hold the CTRL key on the keyboard. The cursor changes to indicate you can add a new label. Left click the location on the contour line where you want the new label to be located.
4. To move a contour label, click on the left, hold down the left mouse button, and drag the label. Release the left mouse button to complete the label movement.
5. To duplicate a label, hold the CTRL key on the keyboard while holding the left mouse button on an existing label. Drag the label to a new location along the line.
6. To exit the Edit Contour Labels mode, press the ESC key.

3.8.7 Modifying an Axis

Adding an Axis Title

1. The “Bottom Axis” object is selected in the Object Manager.
2. The bottom axis properties are displayed in the Property Manager. Click on the General tab.
3. Click Title to open the Title section. Click in the box next to Title text. Type Bottom Axis and press the ENTER key on the keyboard. This places a title on the selected axis.
4. If you cannot see the axis title, click the View | Zoom | Selected command. The map automatically increases its size to fill the plot window.

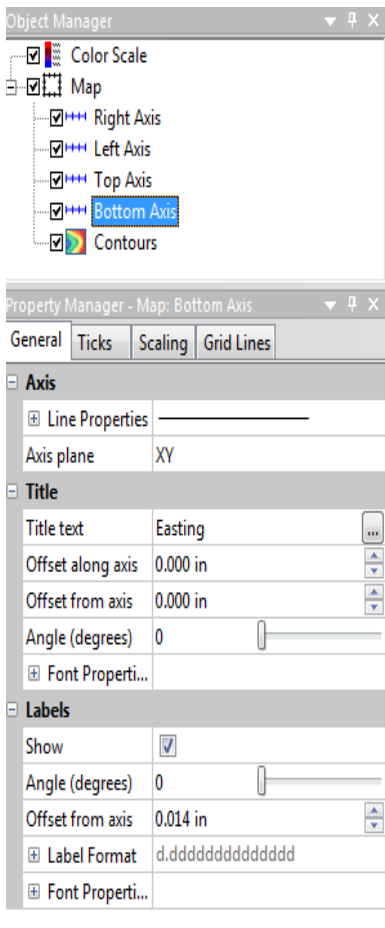


Figure (3.9): Adding an axis title

3.8.8 Creating a 3D Surface Map

1. Click the File | New | Plot command to open a new plot document.
2. Select the Map | New | 3D Surface command or click the button.
3. In the Open Grid dialog, select the grid file project1.grd.
4. Click Open and the 3D surface is created using the default settings.
5. Click once on 3D Surface in the Object Manager. The 3D surface properties are displayed in the Property Manager.
6. Click the Mesh tab.
7. Check the Draw lines boxes in both the Lines of Constant X and Lines of Constant Y sections. The mesh is automatically added to the selected 3D surface.

4. In the Lines of Constant X section, change the Frequency to 5.
5. In the Lines of Constant Y section, change the Frequency to 5.

3.8.9 Exporting Maps

1. Click the File | Export.
2. In the Save as type list, choose the JPG JPEG Compressed Bitmap (*.jpg, *.jpeg) option.
3. Type the name of the file into the File name box.
4. Click saves.
5. The Export Option dialog is displayed, Click Ok to export the Contour Map for studied area that used in this study.

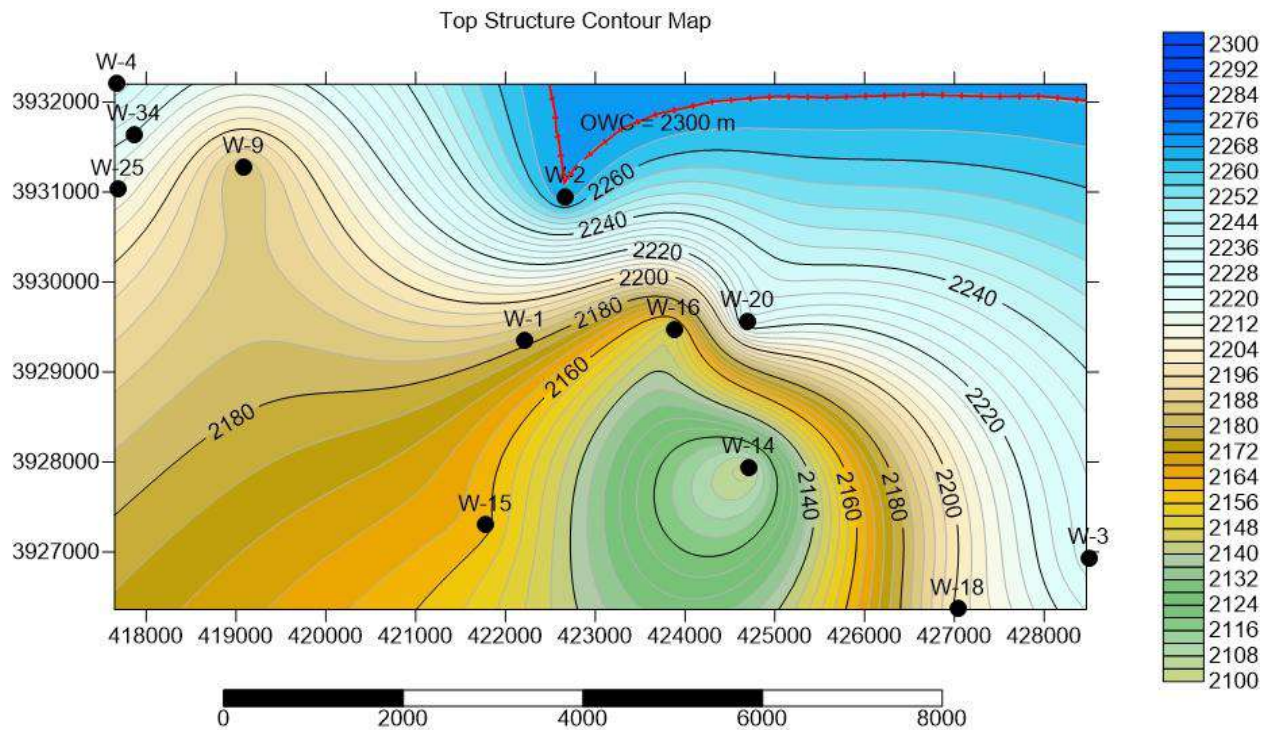


Figure (3.10): Contour Map for studied area that used in this study

Chapter Four

Results and Discussion

4.1 Introduction

This chapter deals with calculating the OOIP and evaluating the main reservoir which contains hydrocarbon.

The determination of original hydrocarbons in place is generally considered the final stage of the static reservoir study. It is during this stage the description of the reservoir, in terms of external and internal geometry, and the properties of the reservoir rock, are quantified through a number expressing the amount of hydrocarbons present in the reservoir at the time of discovery (*Lucia Cosentino, 2001*).

4.2 OOIP Estimation by Using Volumetric Method

Volumetric estimation is the only means available to assess hydrocarbons in place prior to acquiring sufficient pressure and production information to apply material balance techniques. Recoverable hydrocarbons are estimated from the inplace estimates and a recovery factor is estimated from analogue pool performance and/or simulation studies. Therefore, volumetric methods are primarily used to evaluate the in-place hydrocarbons in new, non-producing wells and pools and new petroleum basins. But even after pressure and production data exists, volumetric estimates provide a valuable check on the estimates derived from material balance and decline analysis. Volumetric estimation is also known as the “geologist’s method” as it is based on cores, analysis of wireline logs, and geological maps. Knowledge of the depositional environment, the structural complexities, the trapping mechanism, and any fluid interaction is required to:

- Estimate the volume of subsurface rock that contains hydrocarbons.
- Determine a weighted average effective porosity and water saturation.

With these reservoir rock properties and utilizing the hydrocarbon fluid properties, original oil-in-place or original gas-in-place volumes can be calculated (**Lisa Dean, 2007**).

For oil reservoir (**Anon, 2004**) the original oil-in place (OOIP) volumetric calculation is;

$$OOIP = BRV * NTG * \varphi * (1 - S_w) * \frac{1}{B_o} \quad (4.1)$$

Where;

OOIP = original oil in place. (m^3 at surface condition or *STB* stock tank barrel).

BRV= bulk reservoir volume. (m^3 , ft^3 or barrel).

NTG = Net pay thickness / gross pay thickness. (dimensionless).

φ = Average porosity (Calculated in section 3.4, Chapter Three).

h= thickness.

S_w = Average water saturation (Calculated in section 3.6, Chapter Three)

B_o = Formation volume factor, taken equal to **1.3** (**OEC, 2011**).

To calculate hydrocarbon reserve for any reservoir, many parameters such as cutoff values, pay net, reservoir volume, and other parameters must be calculated.

4.3 Reservoir Bulk Volume Estimation

To calculate volumes, it is necessary to find the areas between contours in structural maps. Reservoir bulk volumes can be computed using two methods:

1. Trapezoidal rule
2. Simpson's rule

For the trapezoidal rule with a contour interval, h, and where net thickness is distance from the top contour to the crest of the reservoir:

$$V = h. [A_o + 2A_1 + 2A_2 + \dots + 2A_{n-1} + A_n] + \left(\frac{hn}{2}\right). A_n \quad (4.2)$$

By using Simpson's rule with a contour interval, h, and an even number of intervals (odd number of lines):

$$V = \left(\frac{h}{2}\right) \cdot [A_0 + 4A_1 + 2A_2 + \dots + 2A_{n-2} + 4A_{n-1} + A_n] + \left(\frac{hn}{2}\right) \cdot A_n \quad (4.3)$$

For the best accuracy, the Pyramidal formula should be used because of its simpler form, however, the trapezoidal formula is commonly used, but it introduces error of 2% when the ratio of successive areas is 0.5. Therefore, a commonly adopted rule in unitization programs is that;

- Whenever the ratio of the areas of any two successive isopach lines is smaller than 0.5, the pyramidal formula is applied.
- Also, whenever the ratio of the areas of any two successive isopach lines is found to be greater than 0.5, the trapezoidal formula is applied.

Reservoir bulk calculated from structural contour map for the studied field and using above equations. The results are summarized in table (4.1).

Table (4.1) Reservoir Bulk Volume for each Unit

contour	Area m ²	Area acre	ratio	VB acre.ft
Ao	1.24E+07	3.06E+03	0.909	
A1	1.13E+07	2.78E+03	0.841	2.59E+04
A2	9.48E+06	2.34E+03	0.835	2.27E+04
A3	7.92E+06	1.96E+03	0.993	1.91E+04
A4	7.86E+06	1.94E+03	0.894	1.73E+04
A5	7.03E+06	1.74E+03	0.972	1.64E+04
A6	6.83E+06	1.69E+03	0.919	1.52E+04
A7	6.28E+06	1.55E+03	0.893	1.44E+04
A8	5.61E+06	1.39E+03	0.931	1.31E+04
A9	5.22E+06	1.29E+03	1.000	1.19E+04
A10	5.22E+06	1.29E+03	0.989	1.15E+04
A11	5.16E+06	1.28E+03	0.902	1.14E+04
A12	4.66E+06	1.15E+03	0.637	1.08E+04
A13	2.96E+06	7.32E+02	0.980	8.43E+03
A14	2.90E+06	7.18E+02	0.654	6.51E+03
A15	1.90E+06	4.70E+02	0.848	5.34E+03
A16	1.61E+06	3.98E+02	0.993	3.92E+03
A17	1.60E+06	3.95E+02	0.813	3.59E+03
A18	1.30E+06	3.21E+02	0.808	3.25E+03
A19	1.05E+06	2.59E+02	0.781	2.65E+03
A20	8.20E+05	2.03E+02	0.732	2.12E+03
A21	6.00E+05	1.48E+02	0.691	1.62E+03
A22	4.15E+05	1.02E+02	0.917	1.17E+03
A23	3.80E+05	9.39E+01	0.474	1.29E+03
A24	1.80E+05	4.45E+01	0.000	9.08E+02
Reservoir Bulk Volume in acre.ft				2.31E+05
Reservoir Bulk Volume in Bbl				2.386E+09

4.4 Cut-Off Determination

The cut-off concept is aimed at defining the effective petrophysical properties of a given geological unit in the presence of poor reservoir zones. In order to assess the efficiency of reservoir recovery mechanisms, the initial hydrocarbon volume must relate to reservoir rock (*Worthington PF, 2008*).

The starting point in determining cut-off is to identify reference parameter that allows us to distinguish between intervals that have reservoir potential and intervals that do not. There is no single universally applicable approach to the identification of cut-off (*Worthington PF, Cosentino, 2005*).

The porosity and water saturations cutoff for each unit are calculated in section 3.7 in chapter Three.

4.5 OOIP Estimation

Initial or original oil in place in Well kz-2 is estimated by using volumetric method, by substituting all parameters such as porosity, water saturation, N/G, as well as reservoir volume in equation (4.1).

The OOIP results for each zone through well kz-2 listed in table (4.2) represents contour map for OOIP_{STB} distribution in Well kz-2 prepared by using EXEL software, where water saturation and porosity are distributed on each unit.

Table (4.2) OOIP results through well kz-2 for each Unit

Units	N/G	Phi	SW	OOIP STB
JERIBE	0.060417	0.064	0.1290	6.18E+06
Unit A1	0.127	0.043	0.1879	8.14E+06
Unit A2	0.3265	0.061	0.1328	31.7E+06
Unit B	0.357414	0.137	0.0106	88.9E+06
Unit BE	0.085107	0.126	0.0180	19.3E+06
Unit E	0.054147	0.060	0.0439	5.70E+06

Chapter Five

Conclusions and Recommendations

5.1 Conclusions

This study demonstrated that the integration of petrophysical analysis and structural mapping provides a reliable approach for estimating the Original Oil in Place (OOIP) using the volumetric method. The use of well log data, including gamma ray, resistivity, density, neutron, and sonic logs, enabled accurate determination of key reservoir parameters such as porosity, water saturation, and shale volume.

The results showed significant variation in reservoir properties among the units studied. Units B and BE exhibited the best reservoir quality, characterized by higher effective porosity and very low water saturation, making them the main hydrocarbon-bearing zones. In contrast, units such as Jeribe and Unit E showed relatively poor reservoir properties and limited contribution to total reserves.

The application of cut-off values (porosity and water saturation) played a crucial role in distinguishing pay from non-pay zones, ensuring more realistic estimation of productive intervals. Additionally, the use of structural contour maps generated through modern software improved the accuracy of reservoir area and bulk volume estimation compared to traditional methods.

The volumetric calculation results indicated that Unit B contributes the largest share of OOIP, highlighting its importance for future development and production planning. Overall, the study confirms that the volumetric method remains an effective and practical technique, especially during early stages of reservoir evaluation where production data are not yet available.

Finally, the study emphasizes the importance of accurate input parameters (such as Archie constants, porosity, and water saturation), as small errors in these values can significantly impact the final OOIP estimation. Future work may include integrating dynamic data (pressure and production data) to further refine reserve estimates and improve reservoir management strategies.

5.2 Recommendations

Based on the results and limitations of this study, the following recommendations are proposed:

1. Integration with Dynamic Data

It is recommended to integrate volumetric results with dynamic reservoir data such as pressure, production history, and material balance analysis to improve the accuracy of OOIP estimation and reduce uncertainty.

2. Use of Advanced Petrophysical Models

Applying more advanced models for water saturation (such as shaly-sand models instead of Archie in complex formations) is recommended, especially in formations with significant shale content.

3. Improvement of Log Interpretation

Future studies should utilize advanced log interpretation software (e.g., Techlog or Interactive Petrophysics) instead of basic tools like Excel to achieve more precise and automated petrophysical evaluation.

4. Core Data Utilization

It is strongly recommended to incorporate more core analysis data (SCAL and RCAL) to better determine reservoir properties and calibrate log-derived parameters such as porosity and Archie constants.

5. Uncertainty Analysis

Performing uncertainty and sensitivity analysis on key parameters (porosity, water saturation, NTG, Bo) is important to understand the range of possible OOIP values rather than relying on a single deterministic estimate.

6. High-Resolution Geological Modeling

Building a 3D geological model of the reservoir using specialized software (e.g., Petrel) is recommended to better represent reservoir heterogeneity and improve volumetric calculations.

7. Refinement of Cut-Off Values

The cutoff values used in this study (porosity and water saturation) should be validated using production data or relative permeability curves to ensure accurate identification of pay zones.

8. Additional Well Data

Including more wells in the study area will enhance the reliability of structural contour maps and reduce interpolation errors in reservoir geometry.

9. Application of Seismic Data

Incorporating 3D seismic data can significantly improve structural interpretation, fault detection, and reservoir boundary definition.

10. Future Enhanced Oil Recovery (EOR) Studies

Since some units show good reservoir quality, it is recommended to evaluate potential EOR methods (such as water flooding or gas injection) to maximize recovery factors.

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Appendix A

A sample of Used Data in this Study

DEPTH	BS	NPHI	RHOB	GR	DT	LLD	LLS	MSFL	SP
2267.407	8.5	0.098918	2.818	30.2803	53.5194	151.0118	196.0852	441.3438	76.9228
2267.56	8.5	0.108765	2.7842	31.3843	54.8676	34.6509	57.2736	127.5186	77.0563
2267.712	8.5	0.119428	2.7577	32.5439	54.8933	20.4035	31.9154	32.1602	77.0143
2267.864	8.5	0.130091	2.7795	33.8886	54.8637	15.3463	19.0551	31.8572	75.7332
2268.017	8.5	0.140753	2.755	35.1981	56.3507	13.2013	16.7319	22.0797	74.1319
2268.169	8.5	0.130012	2.7348	32.9379	55.7799	14.0529	17.7324	16.4179	70.814
2268.322	8.5	0.096861	2.7447	30.6777	54.1562	16.6126	20.9873	22.1347	67.4961
2268.474	8.5	0.076473	2.7796	28.4175	52.5325	23.999	32.1588	48.9834	64.623
2268.626	8.5	0.063994	2.8099	26.7185	51.6132	38.4871	60.2076	85.2638	62.4051
2268.779	8.5	0.063051	2.8336	28.1336	51.1031	52.1923	95.6632	115.6698	61.2594
2268.931	8.5	0.068109	2.8452	32.0823	51.9652	45.7955	99.2304	160.2103	60.5728
2269.084	8.5	0.074665	2.8165	33.1177	53.5212	33.3042	57.4579	129.357	62.0795
2269.236	8.5	0.070541	2.8025	34.0377	53.4037	25.0905	40.9352	65.8043	63.9277
2269.388	8.5	0.064573	2.8111	35.9405	53.7128	20.3199	27.8276	27.9068	65.776
2269.541	8.5	0.061822	2.8203	38.1882	53.5625	17.2103	21.1753	20.1682	66.864
2269.693	8.5	0.069932	2.8258	41.4462	53.5744	18.1243	21.5792	34.7162	67.0488
2269.846	8.5	0.091457	2.7771	45.9402	55.2949	17.6414	20.1842	67.0153	66.3193
2269.998	8.5	0.116668	2.7253	50.4911	58.0681	14.3112	17.0603	48.7331	65.2898
2270.15	8.5	0.141692	2.6986	49.315	59.1624	11.7289	13.8657	29.5459	64.2602
2270.303	8.5	0.159542	2.6816	47.2866	60.1567	9.1466	10.9049	10.3587	63.2307
2270.455	8.5	0.171653	2.6863	45.258	61.7338	8.0916	10.4504	9.4559	62.3208
2270.608	8.5	0.149779	2.699	44.648	57.5743	9.6685	13.6264	18.8382	62.0203
2270.76	8.5	0.139574	2.7322	46.8394	55.5072	11.0299	16.0304	54.2193	61.6693
2270.912	8.5	0.149071	2.7255	51.5461	56.5245	12.0668	15.929	40.1294	60.6183
2271.065	8.5	0.161563	2.6925	58.883	58.2174	10.3943	13.6374	26.0396	59.5672
2271.217	8.5	0.177271	2.6595	66.22	60.6693	8.26	10.5643	18.5659	59.8683
2271.37	8.5	0.197753	2.6341	73.6184	64.3853	6.7212	7.9713	15.1757	60.1653
2271.522	8.5	0.234152	2.6163	75.8885	68.3666	5.1825	5.968	10.8282	60.1653
2271.674	8.5	0.270551	2.6035	69.4026	72.3478	3.6498	4.2095	6.8509	60.1653
2271.827	8.5	0.30695	2.5986	61.585	74.521	2.6342	3.2957	4.3545	59.3738
2271.979	8.5	0.301338	2.5826	54.1334	75.466	2.1963	2.382	2.7682	58.5871
2272.132	8.5	0.247591	2.6348	46.6818	67.5134	2.1251	3.6315	2.6203	57.9007

Appendix B

Effective Porosity, Total Porosity, Shale Volume Calculations in Excel (Sample)

DEPTH	NPHI	RHOB	GR	GRI	Vcl	Øt	Øe	Øavg.	Vsh-avg.
2326.538349	0.156	2.575	7.558	0.000	0.000	0.120	0.120	0.137	0.086
2326.690749	0.159	2.567	7.828	0.006	0.001	0.124	0.124		
2326.843149	0.154	2.547	8.097	0.012	0.003	0.128	0.127		
2326.995549	0.135	2.569	8.367	0.018	0.004	0.111	0.111		
2327.147949	0.109	2.614	8.637	0.024	0.005	0.085	0.084		
2327.300349	0.098	2.621	8.907	0.030	0.007	0.076	0.076		
2327.452749	0.096	2.598	9.465	0.042	0.009	0.083	0.082		
2327.605149	0.104	2.600	10.037	0.055	0.012	0.086	0.085		
2327.757549	0.123	2.610	10.649	0.068	0.016	0.092	0.091		
2327.909949	0.141	2.615	11.405	0.085	0.020	0.100	0.098		
2328.062349	0.159	2.621	12.160	0.101	0.025	0.107	0.105		
2328.214749	0.181	2.579	12.654	0.112	0.028	0.131	0.128		
2328.36715	0.189	2.537	13.052	0.121	0.030	0.148	0.144		
2328.51955	0.192	2.530	13.282	0.126	0.032	0.152	0.147		
2328.67195	0.195	2.526	13.227	0.125	0.031	0.155	0.150		
2328.82435	0.200	2.533	13.172	0.124	0.031	0.155	0.150		
2328.97675	0.205	2.541	13.081	0.122	0.030	0.155	0.150		
2329.12915	0.208	2.528	12.955	0.119	0.030	0.161	0.156		
2329.28155	0.209	2.508	12.829	0.116	0.029	0.167	0.162		
2329.43395	0.205	2.511	12.703	0.113	0.028	0.165	0.160		
2329.58635	0.198	2.516	12.864	0.117	0.029	0.159	0.154		
2329.73875	0.190	2.521	13.104	0.122	0.031	0.154	0.149		
2329.89115	0.185	2.523	13.280	0.126	0.032	0.150	0.146		
2330.04355	0.179	2.527	13.154	0.123	0.031	0.146	0.142		
2330.19595	0.183	2.548	13.028	0.121	0.030	0.142	0.137		

Appendix C

Water Saturation Calculations in Excel (Sample)

N10

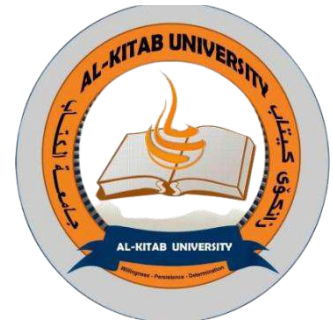
	A	B	C	D	E	F	G	H	I	J	K
1	DEPTH	Rxo	Rt	Øe	S	Sw	Rw @Tf				
2	2442.057554	26.6261	8.1601	0.093785489	0.00957401	0.009574	0.025		a	m	n
3	2442.209954	26.221	8.7816	0.098076492	0.00728394	0.007284			1.07	1.43	1.99
4	2442.362354	27.1178	8.4588	0.09977553	0.00747321	0.007473					
5	2442.514754	27.6009	7.538	0.094064745	0.01111613	0.011116	Sw avg.				
6	2442.667154	26.4967	6.9226	0.087085781	0.0163995	0.0164	0.043902692				
7	2442.819554	24.7652	6.3321	0.080475781	0.02451562	0.024516					
8	2442.971954	23.4539	6.3188	0.078629153	0.0262996	0.0263					
9	2443.124354	20.5368	6.9209	0.085255532	0.01742985	0.01743					
10	2443.276754	21.1434	8.0159	0.090419747	0.01100705	0.011007					
11	2443.429154	26.4644	8.9997	0.101050416	0.00637157	0.006372					
12	2443.581554	29.3275	9.586	0.110564244	0.00435012	0.00435					
13	2443.733954	29.2025	9.3737	0.108567223	0.00479053	0.004791					
14	2443.886354	28.5643	9.0713	0.107327456	0.00528346	0.005283					
15	2444.038754	25.4967	8.8567	0.104310532	0.00600962	0.00601					
16	2444.191154	23.8221	8.659	0.098043269	0.00749784	0.007498					
17	2444.343554	24.6213	8.0778	0.087002934	0.01209566	0.012096					
18	2444.495954	26.5471	7.4958	0.074355472	0.02194782	0.021948					
19	2444.648354	20.9022	7.0922	0.06344338	0.03840082	0.038401					

Appendix D

N/G Calculations in Excel (Sample)

Clipboard Font Alignment Merge & Center								
E2 ✕ ✓ fx =IF(AND(B2<0.1,C2>0.05,D2<0.1),0.1524,0)								
	A	B	C	D	E	F	G	H
1	DEPTH	Vclay	øe	Sw	pay zone			
2	2326.538	0.000001	0.119968803	0.000849205	0.1524		pay zone	23.768
3	2326.691	0.001273659	0.124011955	0.000703852	0.1524			
4	2326.843	0.002568797	0.127188886	0.000387168	0.1524			
5	2326.996	0.003883348	0.110990736	0.000415907	0.1524		Gross	66.5
6	2327.148	0.005218592	0.084204598	0.000700448	0.1524			
7	2327.3	0.006574357	0.075895319	0.0008187	0.1524		N/G	0.35741
8	2327.453	0.009441647	0.082101657	0.000810311	0.1524			
9	2327.605	0.012479999	0.085192958	0.001175553	0.1524			
10	2327.758	0.015839697	0.090781636	0.001868906	0.1524			
11	2327.91	0.020151244	0.097971206	0.002187487	0.1524			
12	2328.062	0.024650868	0.104770841	0.002147339	0.1524			
13	2328.215	0.027696988	0.127528404	0.001143358	0.1524			
14	2328.367	0.030212844	0.143804982	0.000733583	0.1524			
15	2328.52	0.031695137	0.14688863	0.000683698	0.1524			
16	2328.672	0.031340521	0.149765164	0.000707865	0.1524			
17	2328.824	0.030987645	0.150046501	0.000782409	0.1524			
18	2328.977	0.030401724	0.149938918	0.000789256	0.1524			
19	2329.129	0.029597815	0.155862187	0.000706862	0.1524			
20	2329.282	0.028799605	0.162462809	0.000543506	0.1524			
21	2329.434	0.028007054	0.159920831	0.000484653	0.1524			
22	2329.586	0.029018405	0.154341249	0.000468897	0.1524			
23	2329.739	0.03054728	0.149270447	0.000476209	0.1524			
24	2329.891	0.03168412	0.145542213	0.000481084	0.1524			
25	2330.044	0.03087112	0.141941758	0.000513016	0.1524			
26	2330.196	0.030063884	0.137270643	0.00074825	0.1524			
27	2330.348	0.029261736	0.142052426	0.000961344	0.1524			

**University of AL-Kitab
College of Engineering
Petroleum Engineering
Department**



Reservoir Performance Simulation Using CMG-IMEX for a Single Oil Well

A Project Submitted to the College of Engineering
University of AL-Kitab in Partial Fulfillment
Requirements for the Degree of
B.Sc. in Petroleum Engineering

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JUNE 2026

ABSTRACT

Reservoir simulation plays a vital role in understanding reservoir behavior and optimizing oil recovery processes. In this study, the performance of a single oil well was simulated using the CMG-IMEX reservoir simulator. A synthetic reservoir model was developed to evaluate reservoir behavior under primary and secondary oil recovery via water injection. The simulation results showed that primary oil recovery relies solely on natural reservoir energy, which leads to rapid pressure depletion and limited oil recovery. To improve reservoir performance, water injection was introduced as a secondary recovery method. The results demonstrated that water injections effectively maintained reservoir pressure, increased oil production rate, and significantly enhanced cumulative oil production and oil recovery factors. Additionally, water injections improved oil displacement efficiency, as indicated by reduced oil saturation and increased water saturation. Although water cut and produced water volume increased during secondary recovery, overall reservoir performance improved substantially. The study concludes that water injections are an effective method for enhancing oil recovery and extending the productive life of oil reservoirs.

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CHAPTER ONE

INTRODUCTION

1.1 Background of Study

Reservoir simulation is one of the most important tools in petroleum engineering for understanding reservoir behavior and predicting future performance under different production scenarios. With the increasing complexity of oil reservoirs and the high cost associated with field operations, numerical simulation has become essential for efficient reservoir management and decision-making.

Black oil simulators are widely used to model conventional oil reservoirs in which the fluid system consists of oil, water, and gas. Among commercial reservoir simulators, CMG-IMEX is a well-established black-oil simulator capable of modeling primary, secondary, and tertiary recovery processes. It is commonly used to evaluate reservoir performance, forecast production, and assess the impact of different development strategies.

The increasing global demand for crude oil and the limited discovery of new oil reserves have greatly pushed the oil industry towards implementing enhanced oil recovery (EOR) projects [1]. Oil recovery methods can be divided into primary oil recovery, which relies on the natural energy present in the reservoir to drive oil towards production wells. This process typically recovers only a small portion of the original oil in place (OOIP). Secondary oil recovery techniques are then applied, generally extending the productive life of the field by injecting water to displace oil and transport it to producing wells, thereby increasing OOIP [2]. After primary and secondary oil recovery, more than 50% of the OOIP is still trapped in the reservoir. As a result, EOR is applied, and this process involves a combination of methods such as chemical flooding, thermal flooding, miscible flooding, etc. to increase oil production [3].

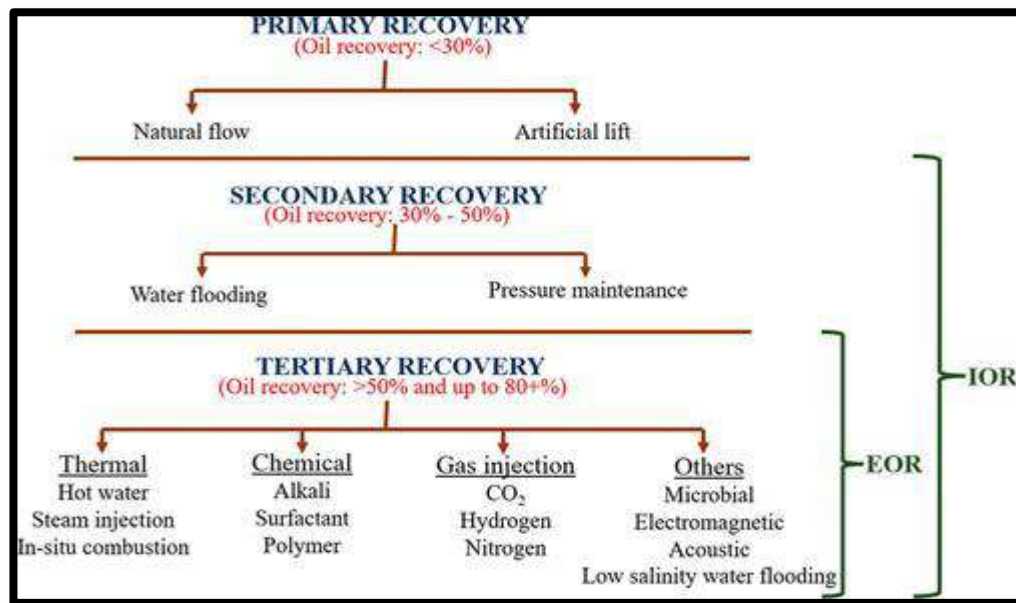


Figure 1-1: Oil recovery classification [4]

1.2 Problem Statement

Oil reservoirs experience a natural decline in pressure and production rate during primary recovery. Relying solely on a single production well without pressure support often results in low ultimate oil recovery and inefficient reservoir exploitation. The challenge addressed in this study is to evaluate how reservoir performance changes when water injection wells are introduced after primary production. Understanding the influence of water injection on pressure behavior, oil production rate, and cumulative recovery is essential for designing effective reservoir development plans.

This research aims to investigate whether water injection can significantly improve reservoir performance compared to production without injection.

1.4 Objectives of the Study

The main objectives of this study are:

- 1) To build a synthetic reservoir model using the CMG-IMEX simulator.
- 2) To simulate reservoir performance with a single oil production well.
- 3) To introduce water injection wells and evaluate their effect on reservoir.
- 4) To compare oil recovery, production rate, and cumulative production before and after water injection.

1.5 Scope and Limitations

- 1) The study uses a synthetic reservoir model rather than real field data.
- 2) Simulation is performed using CMG-IMEX 2021.
- 3) The model includes one production well and one or more water injection wells.
- 4) The study focuses on primary recovery followed by secondary recovery (water injection)

1.6 Limitations of the Study

- 1) Geological heterogeneity is simplified.
- 2) Advanced recovery methods such as gas injection or EOR are not considered.
- 3) Economic analysis is outside the scope of this work.
- 4) Results are specific to the assumed reservoir properties and may not represent all real reservoirs.

CHAPTER TWO

THEORETICAL BACKGROUND

2.1 Introduction

IMEX is one of the world's fastest conventional reservoir simulators. IMEX models complex, heterogeneous, faulted oil and gas reservoirs to achieve accurate predictions and forecasts quickly. Reservoir engineers use IMEX to quickly and easily move from history-matched primary production and waterfloods to enhanced-recovery processes in GEM and STARS.

IMEX is a full-featured three-phase, four-component black-oil reservoir simulator for accurately modeling complex, heterogeneous, faulted structures and primary and secondary (water & polymer flooding) recovery processes using complex horizontal and multilateral wells. IMEX includes features such as local grid refinement (LGR), comprehensive well management, pseudo-miscible option, horizontal wells, dual porosity/permeability, flexible grids, gas adsorption, and many more. IMEX models multiple PVT and equilibrium regions, multiple rock types, and offers flexible relative-permeability options. Regardless of the size or complexity of your reservoir problem, IMEX is an effective tool for a broad range of reservoir management issues. To optimize your reservoir simulation model, use IMEX after history matching to screen multiple recovery techniques and maximize net present value (NPV). The speed of IMEX allows engineers to run more simulations than with any other simulator.

2.2 Benefits of CMG

The computer Modeling Group (CMG) simulation program provides a tool for physicists, geologists, geophysicists, and engineers to predict problems in oil reservoirs before production begins, saving time and enabling the identification of the best solutions with minimal losses. Benefits of the program.

- Achieve simulation results faster than any other conventional simulator
- Ability to quickly screen a variety of recovery mechanisms before moving forward to a more complex simulation
- Accurate modeling of the matrix-fracture transfer in fractured reservoirs
- Use the speed of IMEX to simulate shale gas modeling
- Seamless integration with CMOST for rapid, accurate history matches and uncertainty analysis, while leveraging limited engineering time
- Fast and easy transition to enhanced oil recovery (EOR) process modeling in GEM and STARS

2.3 Applications of CMG's IMEX

Reservoir engineers use IMEX to quickly and easily transition from history-matched primary production and waterfloods to enhanced-recovery processes in GEM and STARS.

- Unconventional gas& Liquids reservoir
- Coal Bed Methane (CBM)
- Shale gas
- Shale liquids
- Tight gas
- primary depletion
- Infill drilling optimization
- Horizontal & multi-lateral well placement
- Coning studies
- Under-saturated/saturated oil reservoirs
- Gas condensate reservoirs
- Gas deliverability forecasting
- Naturally fractured reservoirs
- Gas-oil gravity drainage

- secondary recovery
- Water flooding
- Surface facilities modeling
- Polymer injection
- Dry gas injection
- Pseudo-miscible solvent injection

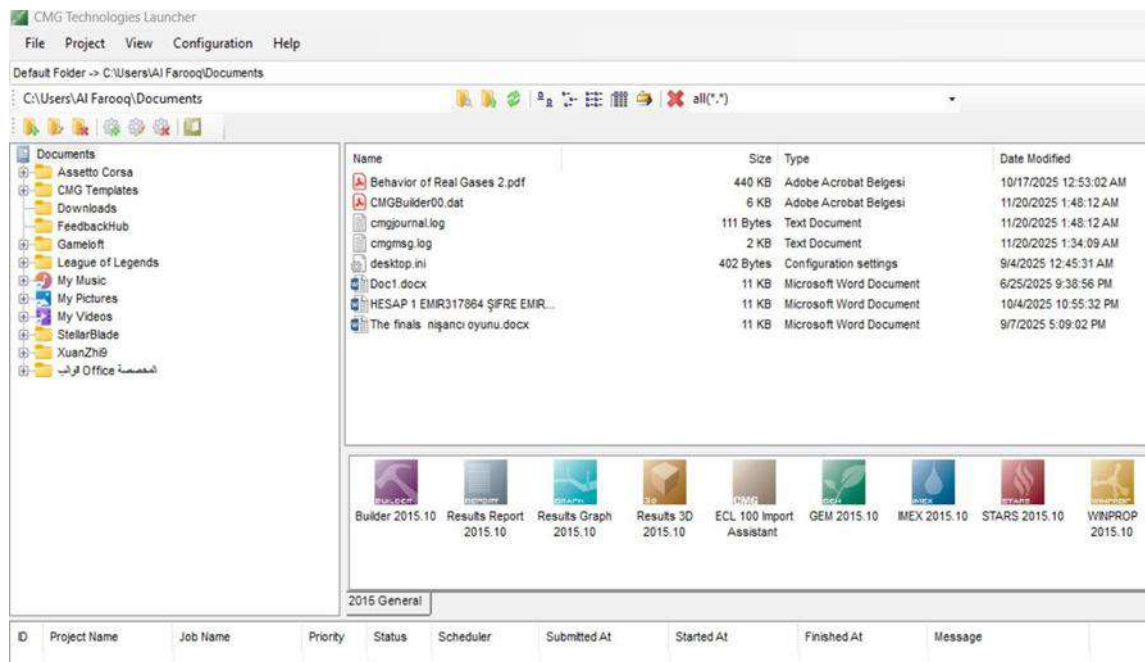


Figure 2-1: CMG's launcher view screen

2.4 Selection of Model Grid

Selection of the x-y-z grid block network involves many factors, including available budget and the engineer's judgment and experience. For any model, the arithmetic or computing expense per time step is at least linearly proportional to the total number of gridlocks employed. The computing expense of a single model run is proportional to the product of the number of gridlocks and the number of time steps required by the model to cover the total time period of interest. In many cases, the time step size is controlled by the maximum rate of change (overall gridlocks) in one or more calculated quantities, such as pressure and saturations. This maximum rate of change generally occurs at or near a well or in the vicinity of a flood front. A doubling of the number of gridlocks can result

in approximately a doubling of this maximum rate of change since each gridlock is (on average) one-half as large. The average time step size might then decrease by a factor of two if the number of blocks were doubled. The final result is a computing expense per model run, which can be approximately proportional to the square of the total number of gridlocks. This indicates the importance of selecting the fewest gridlocks consistent with the reservoir/well description, recovery process characteristics, and the questions asked about reservoir performance.

The number of gridlocks and the resulting study computing expense are lowest when the engineer can justify using a representative element of the total field as the basis for the model study. This may be possible in reservoirs developed with repeated well patterns, for any recovery process---water flooding, CO₂ injection, steam flooding, etc. In such cases, the representative element ideally should be a symmetrical element of the reservoir. In strict terms, this requires a repeated, regular pattern of identically completed and operated wells, a horizontally homogeneous reservoir formation of uniform thickness, and a uniform initial fluid saturation distribution. If these conditions were met, questions regarding total-field optimization, forecasting, and comparative evaluation of recovery processes could be addressed inexpensively by simulating a single pattern (element). While actual reservoirs never satisfy these conditions exactly, representative-element simulation studies are frequently performed for processes with repeated patterns. In some cases, a substantial portion of the reservoir may exhibit only moderate areal heterogeneity and thickness variation. Resultant variation in performance from one pattern to another may be sufficiently small for engineering purposes to justify scale-up of single-pattern results to total field performance. Representative-element simulation is often performed when the study's purpose is the comparative evaluation of alternative recovery processes, rather than forecasting total field performance for a specific process and operating scheme. The justification of single-element simulation implied in such cases is

that the resultant ranking of alternative processes is unaffected by the variations in pattern (element) properties over the field. This justification can be, and frequently is, checked by repeating the various process simulations for two or more patterns with different properties, representative of different portions of the reservoir. Finally, the relatively inexpensive single-element simulation applies to design or optimization studies of a specific recovery process operated in repeated-pattern mode. For a repeated-pattern steam flood, single-pattern model runs have been performed to “optimize” pattern type (e.g., five-, seven-, or nine-spot), size, injected steam quality and rate, well completion, etc. Occasional publications describe single-pattern simulation studies using a one-quarter five-spot or one-quarter nine-spot as the symmetrical element of the respective pattern. Actually, a one-eighth-five-spot or nine –spot (and 1/12 seven-spot) is the smallest symmetrical element and should be used to minimize computing expense. Currently, a major portion of industry-wide effort and computing expense associated with simulation studies is devoted to total-field forecasting of black-oil reservoir performance under a sequence of recovery processes. Typically, the engineer must select a 3D grid for a large reservoir with significant heterogeneity, large areal variation in dip and thickness, irregular well locations, and an increasing number of wells as development progresses. The engineer may face a several-year to many-year period of historical performance under natural depletion, frequently with some natural water encroachment. Study objectives may include history matching, followed by matching and forecasting for a water-flood period, and, in turn, forecasting for a tertiary scheme such as CO₂ injection. The number of gridlocks is the product of the number of areal blocks, $N_x \times N_y$, and the number of grid layers, N_z . Several considerations enter into the selection of these two spacing values. Factors indicating a need for fine areal grid spacing are high well density and sharp or rapid changes (areally) in permeability, porosity, thickness, and dip. Since these factors frequently vary over the field, the x- and y-direction grid spacing is often non-uniform. Grid spacing is generally

increased toward the down-dip reservoir boundaries and increases greatly with distance into the aquifer if the latter is present and included in the grid. In general, of course, the number of areal gridlocks required increases with reservoir size and the number of wells. However, grid spacing ranging from very fine to very coarse may be appropriate for different reservoirs of comparable size. The smallest number of areal blocks (coarsest areal spacing) is associated with reservoir studies limited to natural depletion and crystal or flank gas/or water injection. In such a case, a coarse grid may result in several areal blocks that include two or more similar types (e.g., production) wells, with little loss in

Engineering significance of the simulator results. Large numbers of areal blocks may be required in case of pattern water floods or enhanced recovery processes. A rough guide in this case is the need for at least two, preferably three or more, gridlocks separating each injection-production well pair. However, recent studies describe methods for estimating pseudo-relative permeability curves, which allow the placement of an injector/producer well pair in adjacent blocks. The major factors affecting the number of grid layers (vertical gridlocks) required are the formation stratification, vertical communication, and total thickness. Many reservoirs possess several formation layers that correlate from well to well over much or all of the field. Variations in layer thickness, permeability, and porosity may be significant, and are even greater from one layer to another. The vertical communication (vertical permeability) between adjacent layer pairs may range from zero to very high, both within a single layer pair and between pairs. In general, at least one grid layer should be used for each creatable formation layer. However, common sense and budget constraints argue against defining a large number of very thin grid layers. Three-dimensional reservoir studies typically employ 4 to 12 grid layers, and one or more of these grid layers may be a lumped representation of several thin formation layers. The need to subdivide a single formation layer into two or more grid layers depends on the layer thickness, the fluid-segregation characteristics of the recovery process, and operating rates.

Most recovery processes result in moderate-to-severe gravity segregation of oil and injected fluids; injected water or gas tends to under-run or override oil, respectively; many steam-flood projects exhibit severe override of oil by steam. A formation layer that has significant thickness and zero to poor vertical communication with layers above and below may exhibit a pronounced phase segregation and require two or More grid layers. In the idealized example of a field-wide, pronounced gravity override in a vertically homogeneous reservoir, a variable grid spacing that increases from top to bottom might be specified. That is, four layers with thicknesses of 5, 10, 20, and 25 ft might yield more accurate results than four layers of equal 15-ft thickness. A customary approach to determining N_z is to use the simulation model itself in 2D cross-sectional (x-z slice) mode. For the particular recovery process of interest, x-z model runs are performed by using different numbers of grid layers. Pseudo relative-permeability curves for reflection-phase segregation are calculated from model runs performed with a fine vertical grid spacing. These pseudo-curves are then used in equivalent x-z model runs with fewer grid layers to obtain coarse (vertical) definition results that are similar to the fine-spacing “correct” results. The fewer grid layers from the coarse definition are then used in the 3D reservoir study grid. This concept of generating pseudo-curves for coarse vertical grids that reproduce fine-grid vertical results (using rock- or laboratory-derived relative permeability) has been extended to the areal spacing problem, as mentioned earlier. Obviously, the minimum computing expense is achieved by using a single grid layer to represent the entire formation thickness. This results in a 2D x-y areal grid rather than a 3D grid, and is occasionally justified at the two extremes: very high and zero vertical permeability. Pseudo-relative permeability and capillary pressure curves are discussed for the former case in papers describing the vertical equilibrium (VA) concept, and for the latter case by Hearn.

2.5 Specification of reservoir rock and fluid description data

Geological and petro-physical work based on logs and core analyses yields maps of structure, net $\emptyset h$, and kh products for each of the several reservoir layers. The kh and $\emptyset h$ data are often augmented or modified by results of drill-stem, pressure buildup, and pulse tests. For each layer, the engineer can overlay his areal x-y grid spacing network on these maps and read off the subsea depth ($\emptyset h$) and kh values at the center of each gridlock. These values, along with the gross thickness of each block, are then exported to a data file in a format compatible with the simulation model's requirements. Current research effort is directed toward developing computer programs that accept digitized core analysis, log, and geological data for the selected grid network and, through mapping and interpolation techniques, automatically prepare the simulation input data file. Laboratory core analysis work includes measurement of relative permeability, k_r , and capillary pressure, P_c , curves for several field cores. Variations in rock lithology may result in different sets of k_r and P_c curves across layers and/or areal portions of the reservoir. Most simulation models allow multiple sets of such data in a tabular format, with each set assigned to a user-specified layer/portion of the reservoir. If the rock water/oil (gas/oil) capillary pressure values are small, the water/oil (gas/oil) transition zone in the reservoir may be a very small fraction of the total formation thickness. In such cases, pseudo-capillary-pressure curve(s) should be used. For black-oil studies, laboratory tests are performed to determine the gas compressibility factor and the saturated oil and gas viscosities as functions of pressure. Differential and/or constant-composition expansion tests on oil samples yield the pressure-dependent formation volume factor for saturated oil, B_o (RB/STB), and the solution gas, R_s (scf/STB). The resulting oil and associated gas properties vs. pressure are entered into the data file in a tabular format compatible with the simulator's input requirements. For gas condensate depletion studies, constant-volume and constant-composition expansion tests yield the required pressure-dependent liquid content, CL (STB/scf), and condensate

density values. A wide variety of laboratory tests are performed for compositional model studies involving the injection of non-equilibrium fluids (dry or enriched gas, CO₂, N₂, etc.). Swelling tests yield relative volumes, saturation pressure, and equilibrium phase composition for each mixture in a sequence, e.g., 1 mole of original reservoir oil and 1 mole of injected fluid.

2.6 Validity of simulation results

Uncertainties or errors in simulation model results may arise from questionable assumptions or mechanisms not represented in the model's differential form, spatial and temporal truncation errors introduced by replacing the model's differential equations with finite-difference approximations, and inadequately known reservoir rock and/or fluid description data. In addition, the exact solution of the difference equation is not attained because of the round-off error introduced by the finite word length of the computer. Round-off error is generally negligible compared with errors from the other three sources. With some exceptions, the above sources of error are listed in order of increasing importance. However, successful history matching can reserve the importance of the second and third sources.

Comparisons of model and laboratory Experiment results can indicate model validity in the absence of uncertainty 3 above. Several such comparisons show good agreement between model and Experiment for gas/oil systems, water/oil coning, and fractured-matrix imbibition.

2.7 Model Assumption

An assumption common to many black-oil models is that free gas is fully resolved according to the saturated $R_s(p)$ curve during repressurization. This may be a poor assumption in a case where gridblock thickness is large and gas/oil gravity (vertical) segregation is pronounced. Before re-pressurization in a given block, the free gas may exist at high saturation only in the upper portion of the block. This contradicts the model's representation of it as a lower-saturation

distribution throughout the entire block volume. In the segregated state, the gas will re-dissolve only in the lower, residual oil-saturated portion of the block volume, or in the upper, gas-occupied portion. However, the model will allow resolution of the entire rock's oil volume. Pressure hysteresis in the $R_s(p)$ curve has been used to address this problem; an alternative remedy, where the computing budget permits, is to use more grid layers. An assumption common in early black-oil models was that the reservoir oil obeyed a single pair of $Bo(p)$ and $R_s(p)$ curves. Some black-oil reservoirs exhibit significant variation in oil API gravity and PVT behavior with depth and/or areal location. In some cases, this variation can be represented in a black-oil model by allowing the initial solution gas R_{si} to vary with depth in the undersaturated oil column, while retaining a single set of $Bo(p)$ and $R_s(p)$ curves. In other cases, multiple sets of these curves and two oil components are necessary, and the single-oil-type assumption in a black-oil model can lead to appreciable error. Mechanisms or phenomena that are significant in some reservoirs but may not be represented in the model include compaction, hysteresis in wetting- and non-wetting-phase relative permeabilities, and interlayer wellbore cross-flow. The latter is a particularly difficult modeling problem and the subject of continuing research. A production well completed in multiple layers may exhibit production from some layers and, simultaneously, injection (backflow or recirculation) into others. Factors that promote this possibility include low-pressure drawdown (high PI and/or low rate) and poor vertical communication between reservoir layers near the well. A rigorous treatment of this problem requires modeling of wellbore multiphase hydraulics and phase segregation combined with calculation of correct phase mixtures for the layers undergoing injection.

2.8 Oil Recovery Techniques

Oil recovery technology is an extremely important part of the petroleum industry. It includes a wide range of techniques designed to extract the optimal amount of oil from reservoirs beneath the Earth's surface. As global energy demand has risen, optimizing oil recovery has become paramount for sustainable resource utilization. Oil extraction from any reservoir passes through three stages. The initial step is the extraction of oil from the reservoir using natural reservoir pressure; the next phase is pumping saline water to maintain well pressure after pressure falls [5]. As a result, it pushes oil up from the well, enhancing oil recovery. During the primary and secondary stages of oil recovery, approximately 20–30% of the OOIP from the well is extracted. Although about 70% of the oil remains in the reservoir, it is considered depleted. To recover the remaining oil, a third stage, known as Enhanced Oil Recovery (EOR) or tertiary recovery [6], is employed. Whereas secondary oil recovery techniques only sweep oil through the reservoir by injecting water or gas, without altering the properties of the hydrocarbons, enhanced oil recovery methods involve changing the reservoir [7]. In other words, EOR methods alter the natural or actual properties of the wells, such as the density and viscosity of the crude oil, thereby making the disposition process easier. By applying EOR techniques, oil recovery can increase to up to 75%, depending on the technique employed. We will discuss all three stages in detail in the upcoming parts.

2.8.1 Primary Oil Recovery

This technique is the initial step in oil extraction, which involves the natural potential energy of the reservoirs, such as pressure, and mechanical methods to bring the oil to the surface. This method relies solely on the natural pressure of the reservoirs, which is the primary factor in oil production. But this driving force, or the natural pressure energy, is depleted in the early production life of the reservoir. Hence, it needs to be re-pressurized to prolong the reservoir's

production life. That is why secondary oil recovery techniques are used to extend the reservoir's production life and recover more oil. Primary recovery methods include: (i) Natural reservoir pressure; the natural pressure within the reservoir itself is sufficient to force oil to the surface, allowing for oil recovery without additional artificial methods. (ii) Mechanical lifts; When the natural pressure is insufficient, mechanical lifts such as pumps or other artificial lift mechanisms are employed to bring oil to the surface. However, primary recovery techniques usually recover only a small portion of the total oil present in the reservoir, leaving a substantial amount unrecovered. The following are some examples of primary oil recovery techniques: natural flow, pumping systems, gas lift, rod pumping, and plunger lift.

2.8.2 Secondary Oil Recovery

Secondary recovery methods aim to enhance oil recovery beyond what primary methods can achieve. These techniques involve injecting external fluids into the reservoir to displace oil and improve recovery rates. Key secondary recovery techniques include:

2.8.2.1 Water Flooding

Water flooding is a viable alternative for bringing wells back into production by maintaining pressure [8]. After some reserves were recovered, the pressure decreased, causing the recovery process to decline. By injecting water into the reservoir, we can control reservoir pressure and manage oil displacement to the producing wells. Water injection is cost-effective because of the abundance of water resources and its desirable characteristics, such as viscosity, density, and wetting properties. Two factors determine the time and schemes for implementing the water flooding: (i) the amount of producible oil reserves, and (ii) the nature of the drive mechanisms of the reservoirs. One of the most promising candidates for water flooding is the solution-gas-drive reservoir.

The water-flooding technique was used worldwide in the 1960s in most fields to recover much more oil. The success of this technique depends on the properties of the crude oil and the rock formation, such as residual oil saturation, the initial gas saturation rate of injection, and the arrangement of the injectors and producers [9]. The water-flooding technique is not applicable and effective enough in all types of reservoirs. For example, it does not displace all the oil from pore spaces in carbonate reservoirs due to capillary pressure differences and the wettability of the reservoir rock [10], [11]. Because carbonate reservoirs are fractured, they contain many cracks and fractures through which water cannot flow. These reservoirs are characterized by vugs, multiple porosity, and extremely low homogeneity, which lead to poor oil sweep efficiency [8]. To overcome this challenge, a new technique known as low-salinity water injection (LSWI) emerged. Utilizing low-salinity water in the water-flooding process shifts the rock's wettability towards a more water-wet state and releases oil trapped in the pores [12], [13]. Low-salinity water injection is an emerging and improved oil recovery technique, and several design aspects to assess its suitability have been analyzed [14], [15]. Low-salinity water injection is used in light crude oil reservoirs with some clay, provided the clay content is not high. It is proven that high temperature, low acid number, and the presence of Ca^{++} , Mg^{++} , or SO_4^{2-} are favorable for low salinity injection in carbonate reservoirs.

2.8.2.2 Gas Injection

Gas injection methods in the oil recovery process have played an essential role in maximizing hydrocarbon recovery from reservoirs. This technique, developed in 1864, is one of the oldest methods used in fluid injection to support reservoir pressure cost-effectively. Gas injection in reservoirs can be implemented either before the recovery process begins or during recovery as pressure declines. Two schemes used for applying this technique: (i) Crest Gas Injection, also known as top-down gas injection, which means this is a method of injecting gases into the upper sections or crest of the reservoir. The advantages of applying this technique

include targeting bypassed oil zones, minimizing the risk of early gas breakthrough, and improving the overall sweep efficiency of the injected gas. (ii) Pattern Gas Injection; it involves distributing the gas injection wells throughout the oil reservoir in a particular pattern, and the injection wells are deployed into the oil column [16].

The typical or usual gases that are applied in gas injection are: methane, nitrogen, carbon dioxide, associated petroleum gases, glue gases, and air [17]. Some parameters should be considered while applying gas injection, like: (i) the gas injection rate and the time period should be sufficient, (ii) continuous monitoring and measurement are vital, (iii) enough waiting time before and after injection, and (iv) conducting a pilot test in the early life of the developed field. Several factors are significant when determining the application of gas injection techniques. These include the thickness of net pay in the reservoir, the dimensions and relative thickness of the gas cap, the pressure and temperature conditions within the reservoir, and the dissolved gas content and shrinkage factor [18].

2.8.3 Enhanced Oil Recovery

The third and final stage of oil recovery is known as tertiary recovery or enhanced oil recovery (EOR). After the primary and secondary recovery stages, a significant portion of oil remains trapped within the reservoir due to capillary forces, high viscosity, and unfavorable mobility conditions. Unlike the previous stages, which mainly rely on natural pressure and fluid injection, EOR techniques focus on altering the physical and chemical properties of the reservoir system, including rock wettability, oil viscosity, interfacial tension, and fluid density, to improve oil displacement and recovery efficiency [19].

EOR methods are generally classified into three main categories: chemical, gas, and thermal EOR [20]. Chemical EOR involves injecting chemical agents, such as surfactants, polymers, and alkali solutions, to reduce interfacial tension and improve sweep efficiency during water flooding. Gas EOR involves injecting

gases such as carbon dioxide (CO_2), nitrogen (N_2), methane (CH_4), or other hydrocarbon gases to reduce oil viscosity, swell the oil, and enhance its mobility toward production wells. Thermal EOR methods are particularly effective for heavy-oil reservoirs (API gravity less than 20°), where heat is introduced—typically through steam or hot-water injections to reduce oil viscosity and facilitate its flow to the surface [21].

One of the most critical parameters influencing the performance of EOR processes is the mobility ratio between the displacing fluid and the displaced oil. For efficient displacement, the mobility ratio should be less than one to ensure stable displacement and minimize viscous fingering [22]. However, in gas injection processes, the mobility ratio is often greater than one due to the significantly lower viscosity of gases compared to reservoir oil, which can lead to early breakthrough and reduced sweep efficiency [23].

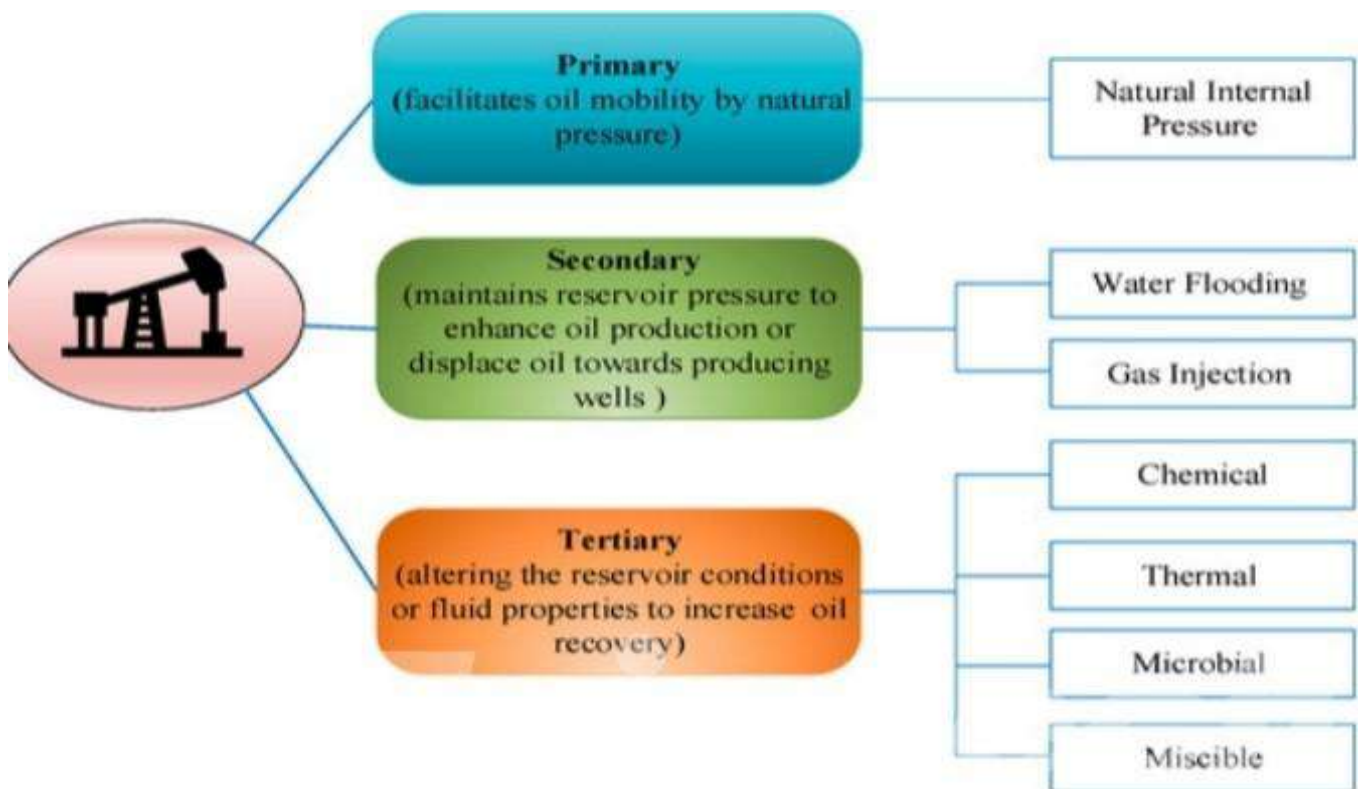


Figure 2-2: Oil Recovery Process

CHAPTER THREE

METHODOLOGY

3.1 Reservoir Simulation

Reservoir simulation is based on well-known reservoir engineering equations and techniques - the same equations and techniques the reservoir engineer has been using for years. In general, simulation refers to the representation of some process by either a theoretical or a physical model. Here, we limit ourselves to simulating petroleum reservoirs. Our concern is the development of petroleum reservoirs. Our concern is the development and use of models that describe the reservoir performance under various operating conditions. Performance under various operating conditions. Reservoir simulation itself is not really new. Engineers have long used mathematical models to perform reservoir engineering calculations. Before the development of modern digital computers, however, the models were relatively simple. For example, when calculating the oil in place volumetrically, the engineer simulated the reservoir using a simple model that employed average values for porosity, saturation, and thickness. Although simulation in the petroleum industry is not new, the new aspects are that more detailed reservoir features, and thus more accurate simulations, have become practical because of the capability afforded by the computers now available. The more detailed description, however, requires complex mathematical expressions that are difficult to understand, leading some engineers to shy away from using simulators and others to misuse them. We in the petroleum industry are at the forefront of the reservoir simulation revolution. As time goes on, simulators will be used increasingly, so a basic understanding of reservoir modelling is essential. The engineer, especially, must

become competent in setting up simulation problems, in deciding on appropriate input data, and in evaluating the results.

3.2 CMG Software

CMG (Computer Modelling Group Ltd.) software is used to predict the flow of fluids (typically, oil, water, and gas) through porous media. It delivers a paradox: fast answers from complex reservoirs, with easy-to-use products and workflows. CMG continues to break new ground for simulator capabilities, model building, and the refinement of advanced recovery processes. CMG exceeds customers' expectations every year.

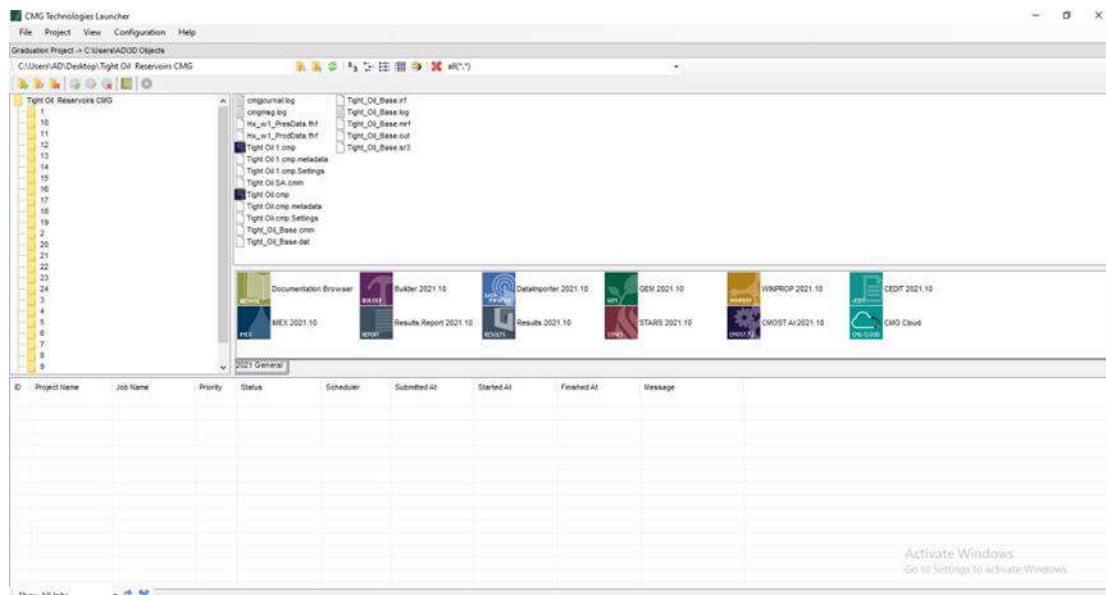


Figure 3-1: CMG Program interface.

As shown in the interface, the program has several tools, which are:

Builder (Fig. 3.2A): Creation of simulation models by providing a framework for data integration and workflow management between IMEX, GEM, STARS, and external data sources.

IMEX (Fig.3.2B): Primary and secondary oil recovery processes in conventional and unconventional reservoirs.

GEM (Fig.3.2C): is the world-leading Equation-of-State (EoS) Reservoir simulator for compositional, chemical, and Unconventional reservoir modelling

STARS (Fig. 3.2D) is the undisputed industry standard for the advanced modelling of recovery processes involving Steam, solvents, air, and chemicals.

Results (Fig.3.2E): helps you increase understanding and insight into recovery processes and reservoir performance with State-of-the-art visualization and analysis capabilities

Win Prop (Fig. 3.2F) is an integral component of advanced reservoir simulation modelling and is invaluable for multiphase and special processes, as well as for cases with compositional variations.

CMOST-AI (Fig.3.2G): Extends your capabilities and potential to improve business decisions and processes. Identify the best solution for your reservoir by combining advanced statistical analysis, Machine learning, and non-biased data interpretation with your engineering expertise.

(Following our understanding of the CMG Program and its tools, we will use in our project a tool to add effective parameters and modifications to the model (Builder), and a tool to evaluate the results.)

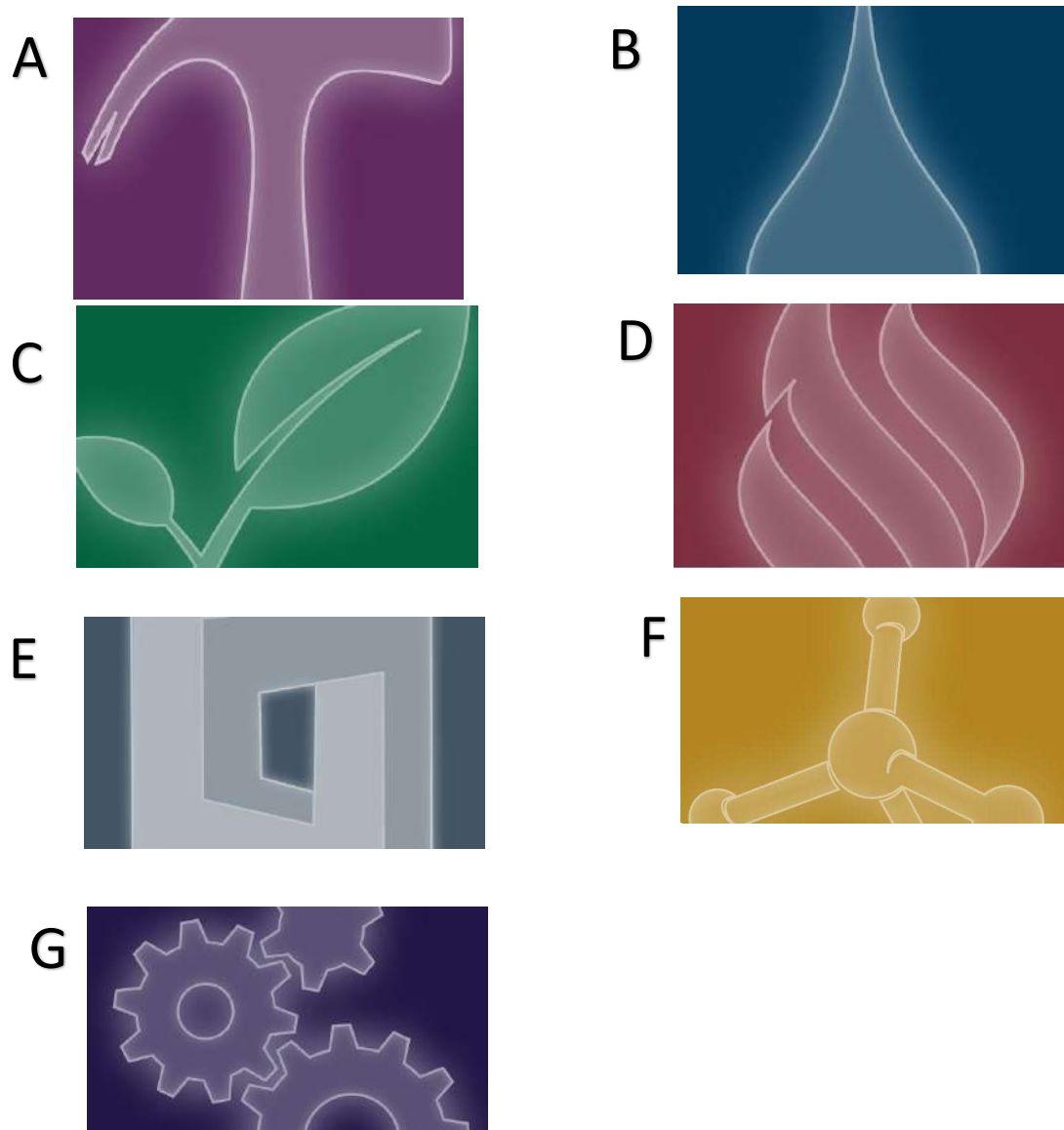


Figure 3-2:CMG interface

3.3 Reservoir Simulation Model

The reservoir simulation model used in this study was developed using the CMG IMEX simulator. The required input data were obtained from the CMG library and implemented within the Builder interface to construct a representative reservoir model.

3.3.1 Simulator Selection and Settings

The first step in this work was to select the IMEX simulator package and define the unit system (field units) and other general simulation settings.

Builder - Reservoir Simulator Settings

Simulator

- ☐ GEM
- ☒ IMEX
- ☐ STARS

Working Units

- ☐ SI
- ☒ Field
- ☐ Lab
- ☐ MODSI

Advanced...

Porosity

- ☒ Single Porosity
- ☐ DUALPOR
- ☐ DUALPERM
- ☐ MINC
- ☐ SUBDOMAIN

Shape Factor

- ☒ Gilman and Kazemi
- ☐ Warren and Root
- ☐ K-Harmonic
- ☐ PI2
- ☐ KX - Matrix Perm I
- ☐ K-Av Harmonic

Subdivisions for Matrix Blocks

Number of subdivisions: 2

Volume fractions (2 values expected):

Simulation Start Date

Year: 2013 Month: 1 Day: 1

OK Cancel

Figure 3-3: Builder reservoir simulator settings

3.3.2 Reservoir Geometry and Grid Design

The reservoir model geometry was defined using a radial grid system centered around a vertical well. The main dimensions and grid parameters are summarized in Table 3-1.

Table 3-1: Reservoir Grid and Geometry Parameters

Parameter	Value
Radial Extent (ft)	2050
Wellbore Radius (ft)	0.25
Angular Divisions	10
Number of Radial Blocks	10
Number of Vertical Layers	10
Top Depth (ft)	9000
Dip Angle (°)	0

The radial grid boundaries were designed to provide higher resolution near the wellbore, which improves simulation accuracy.

Figure 3-4: Reservoir model dimensions (radial grid system)

3.3.3 Rock Properties and Reservoir Characterization

The reservoir rock properties were defined for each layer, including thickness, porosity, and permeability in both horizontal and vertical directions.

Table 3-2: Layered Rock Properties

Layer	Thickness (ft)	Porosity	Kx (md)	Kz (md)
1	20	0.087	35	3.5
2	15	0.097	47	4.75
3	26	0.111	148	14.8
4	15	0.16	202	20.2
5	16	0.13	90	9
6	14	0.17	418	41.8
7	8	0.17	775	77.5
8	8	0.08	60	6
9	18	0.14	682	68.2
10	12	0.13	472	47.2

These properties reflect the heterogeneity and anisotropy of the reservoir formation.

General Property Specification

Edit Specification

Only for Start Time, Go to Property: Use Regions / Sectors Copy Proper

	Grid Top	Grid Thickness	Porosity	Permeability
UNITS:	ft	ft		
SPECIFIED:	X	X	X	
HAS VALUES:	X	X	X	
Whole Grid				
Layer 1	9000	20	0.087	35
Layer 2		15	0.097	47
Layer 3		26	0.111	148
Layer 4		15	0.16	202
Layer 5		16	0.13	90
Layer 6		14	0.17	418
Layer 7		8	0.17	775
Layer 8		8	0.08	60
Layer 9		18	0.14	682

OK Cancel

Figure 3-5: Rock properties definition in CMG

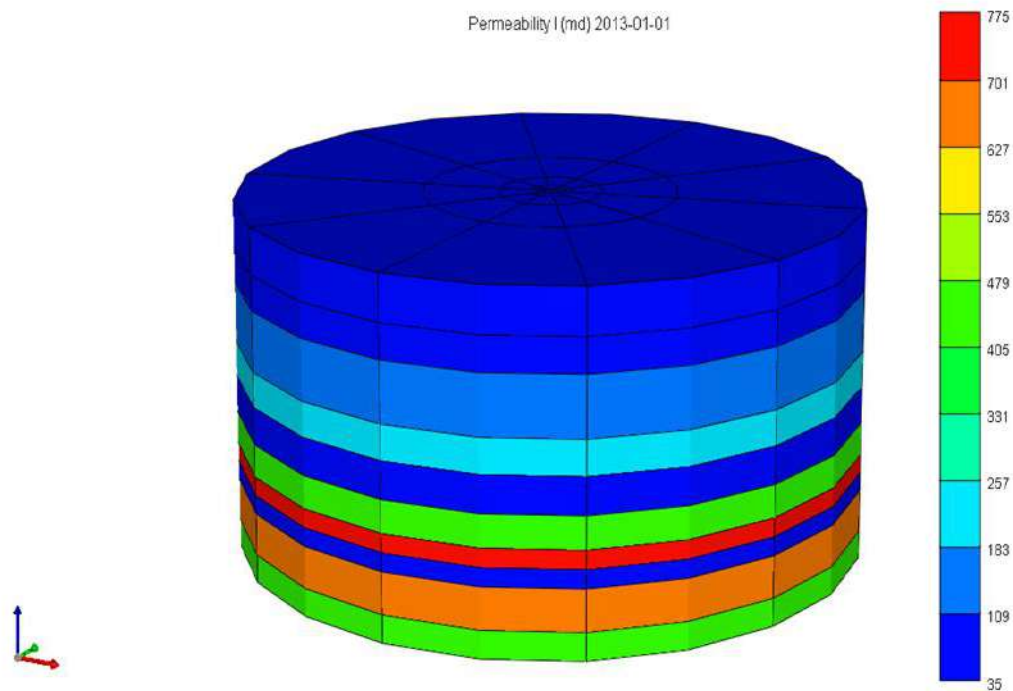


Figure 3-6: 3D view of the simulation model

3.3.4 Rock and Fluid Properties

The rock and fluid compressibility and density properties were defined to represent realistic reservoir behavior.

Table 3-3: Rock and Fluid Properties

Property	Value
Pore Compressibility (1/psi)	4×10^{-6}
Reference Pressure (psi)	3600
Water Compressibility (1/psi)	3×10^{-6}
Oil Compressibility (1/psi)	1×10^{-5}
Oil Density (lb/ft ³)	45
Water Density (lb/ft ³)	63.02
Gas Density (lb/ft ³)	0.0702

The screenshot shows the 'Imex PVT Regions' dialog box with the 'General' tab selected. The 'PVT Region' is set to 1. The 'PVT Table' section contains a table with 14 rows of properties. The 'Value' column for each row is highlighted in yellow. The 'Comments for REFPW' section is empty.

#	Description	Option	Default	Value
1	Reservoir temperature (T...)			120 F
2	DENSITIES			
3	Oil density (DENSITY O...)	Stock tank oil de...		45 lb/ft3
4	Gas density/gravity (DE...)	Gas gravity (Air=1)		0.65
5	Water phase density (D...)			63.02 lb/ft3
6	Undersaturated Co (CO)			
7	Vo pressure dependence...		0 cp/psi	
8	Water properties			
9	Formation Volume Fact...			1.00422
10	Compressibility (CW)			2.88935e-06 1/psi
11	Reference pressure for ...			3600 psi
12	Viscosity (VWI)		1 cp	0.724634 cp
13	Pressure dependence ...		0 cp/psi	0 cp/psi
14	Solution gas ratio max. inc...	Not Used		

Comments for REFPW

OK Cancel Apply Help

Figure 3-7: Rock and fluid property definition

3.3.5 PVT Data

The pressure-volume-temperature (PVT) properties were defined using tabulated data to describe the behavior of oil, water, and gas phases. The gas expansion factor was calculated from the gas formation volume factor to ensure consistency with the simulation model.

Table 3-4: PVT Properties

Pressure (psia)	Bo (RB/STB)	Oil Density (lb/ft ³)	Oil Viscosity (cp)	Rs (scf/STB)	Bw (RB/STB)	Water Density (lb/ft ³)	Water Viscosity (cp)	Bg (MCF/STB)	Gas Density (lb/ft ³)	Gas Viscosity (cp)
400	1.012	46.497	1.17	165	1.01303	62.212	0.96	5.9	2.119	0.013
800	1.0255	48.1	1.14	335	1.01182	62.286	0.96	2.95	4.238	0.0135
1200	1.038	49.372	1.11	500	1.01061	62.36	0.96	1.96	6.379	0.014
1600	1.051	50.726	1.08	665	1.0094	62.436	0.96	1.47	8.506	0.0145
2000	1.063	52.072	1.06	828	1.0082	62.51	0.96	1.18	10.596	0.015
2400	1.075	53.318	1.03	985	1.007	62.585	0.96	0.98	12.758	0.0155
2800	1.087	54.399	1.00	1130	1.0058	62.659	0.96	0.84	14.885	0.016
3200	1.0985	55.424	0.98	1270	1.0046	62.734	0.96	0.74	16.896	0.0165
3600	1.11	56.203	0.95	1390	1.00341	62.808	0.96	0.65	19.236	0.017
4000	1.12	56.93	0.94	1500	1.00222	62.883	0.96	0.59	21.192	0.0175
4400	1.13	57.534	0.92	1600	1.00103	62.958	0.96	0.54	23.154	0.018
4800	1.14	57.864	0.91	1676	0.99985	63.032	0.96	0.49	25.517	0.0185
5200	1.148	58.267	0.90	1750	0.99866	63.107	0.96	0.45	27.785	0.019
5600	1.155	58.564	0.89	1810	0.99749	63.181	0.96	0.42	29.769	0.0195

3.3.6 Rock–Fluid Interaction

The rock–fluid interaction was defined by relative permeability relationships that describe multiphase flow within the reservoir.

Table 3-5: Water–Oil Relative Permeability

Sw	0.22	0.3	0.4	0.5	0.6	0.8	0.9	1
Krw	0	0.07	0.15	0.24	0.33	0.65	0.83	1
Krow	1	0.4	0.125	0.0649	0.0048	0	0	0
Pcow	7	4	3	2.5	2	1	0.5	0

Table 3-6: Gas–Oil Relative Permeability

Sg	0	0.04	0.1	0.2	0.3	0.4	0.5	0.6	0.7
Krg	0	0	0.022	0.1	0.24	0.34	0.42	0.5	0.8125
Krog	1	0.6	0.33	0.1	0.02	0	0	0	0
Pcgo	0	0.2	0.5	1	1.5	2	2.5	3	3.5

These curves were implemented using Corey-type correlations to simulate realistic displacement mechanisms.

Rock Types

Rock Type: 1

Rock Type Properties | Relative Permeability Tables | Hysteresis Modelling

Liquid-Gas Kr Table dependency: ☒ Liquid Saturation ☐ Gas Saturation

Relative Permeability Table: Water-Oil Table

Tools

☐ Include capillary pressure (drainage curve if using hysteresis)

☐ Include capillary pressure hysteresis (imbibition curve)

☐ Include water gas relative permeability in table

☐ Include irreducible oil saturation due to water blocking in table

Smoothing method for table end-points: Power law or quadratic smoothing

☐ Specified threshold value for end-point determination: 5e-07

☒ Use new option for rel. perm. table end point scaling (8 end points vs. 4)

☐ Measured liquid saturation does not include connate water saturation

	Sw	krw	krow	Comment
1	0.22	0	1	
2	0.30	0.07	0.4	
3	0.40	0.15	0.125	
4	0.50	0.24	0.0649	
5	0.60	0.33	0.0048	
6	0.80	0.65	0	
7	0.90	0.83	0	
8	1.00	1	0	
9				
10				

☐ Reduce vertical extent of Pcow cycle for trapped oil hysteresis (DAMP-PCOW-TROIL)

OK Cancel Apply Help

Figure 3-8: Water–oil relative permeability curves

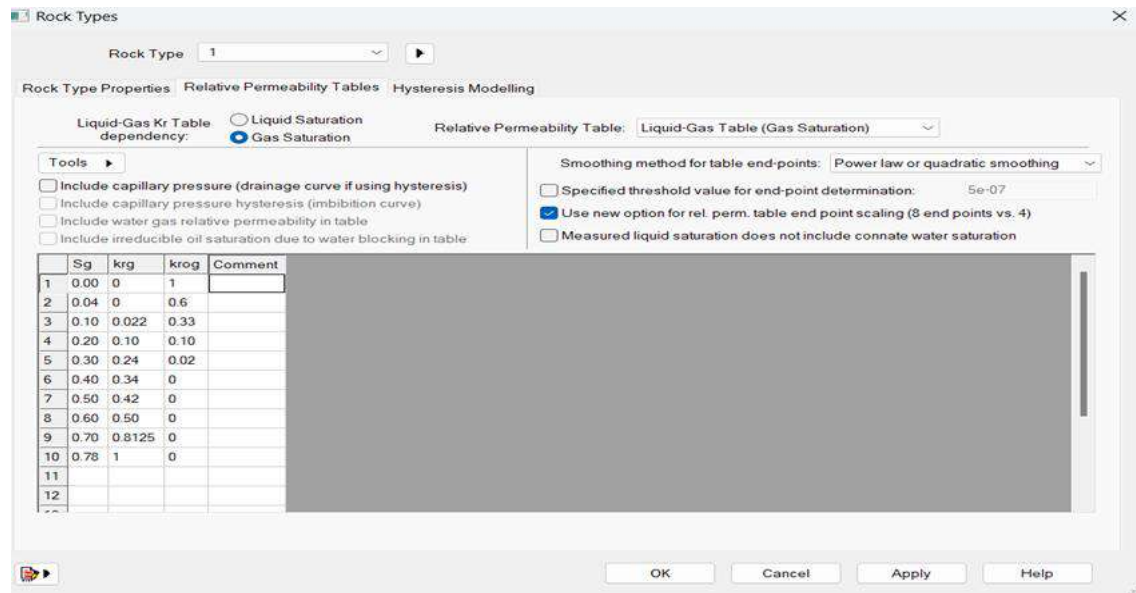


Figure 3-9: Gas–oil relative permeability curves

3.3.7 Initial Conditions

The reservoir initial conditions were defined assuming a saturated reservoir system. No capillary pressure effects were considered in this study.

Table 3-7: Initial Conditions

Parameter	Value
Reference Pressure (psi)	3600
Reference Depth (ft)	9100
Gas–Oil Contact (ft)	9050
Water–Oil Contact (ft)	9120
Bubble Point Pressure (psi)	3600

Initial Conditions

Perform Gravity-Capillary Equilibrium of A Reservoir Initially Containing

☒ Water, Oil, Gas (VERTICAL DEPTH_AVE WATER_OIL_GAS EQUIL)

☐ Water, Oil (VERTICAL DEPTH_AVE WATER_OIL EQUIL)

☐ Water, Gas (VERTICAL DEPTH_AVE WATER_GAS EQUIL NOTRANZONE)

There will be no residual saturation in Gas Cap (GASZONE NOOIL)

Reference Pressure and Depth

Pressure (REFPRES) 3600 psi

Depth (REFDEPTH) 9100 ft

Phase Contact Depths

Water-Oil Contact (DWOC) 9120 ft

Gas-Oil Contact (DGOC) 9050 ft

Water-Gas Contact (DWGC)

Datum Depth for Output Pressure

Note: This item is optional.

Depth (DATUMDEPTH depth)

Pressure will be corrected using the initial equilibrium pressure distribution (DATUMDEPTH depth INITIAL)

Bubble Point Input Format

☒ Reservoir initially saturated (PB = P)

☐ Constant Bubble Point Pressure (PB)

For more options use the Advanced Interface

Advanced

OK Cancel Apply Help

Figure 3-10: Initial condition setup

3.3.8 Production Well Configuration

A production well was defined in the model to simulate primary recovery conditions.

Table 3-8: Production Well Specifications

Well Name	Location
Production Well	(1,1,1-10)

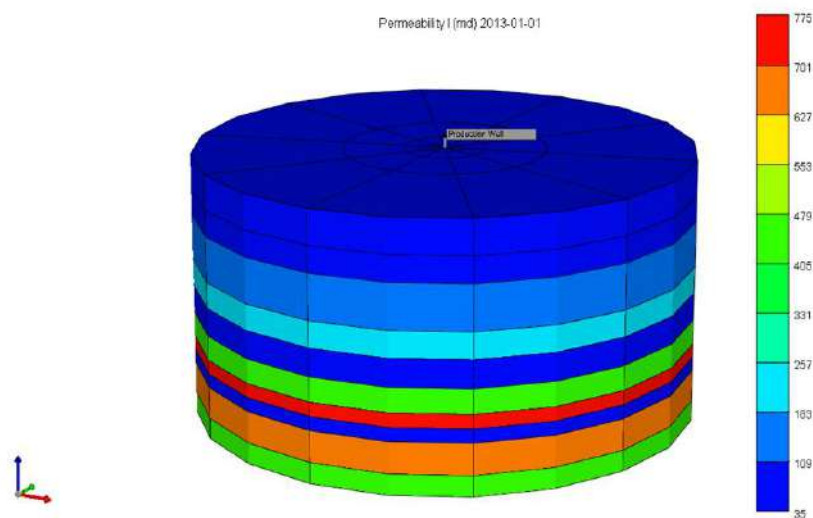


Figure 3-11: Production well configuration

3.3.9 Secondary Oil Recovery (Water Injection)

To enhance oil recovery, water injection was implemented using two vertical injector wells.

Table 3-9: Injector Wells Specifications

Well Name	Location
Injector 1	(10,2,1–10)
Injector 2	(10,7,1–10)

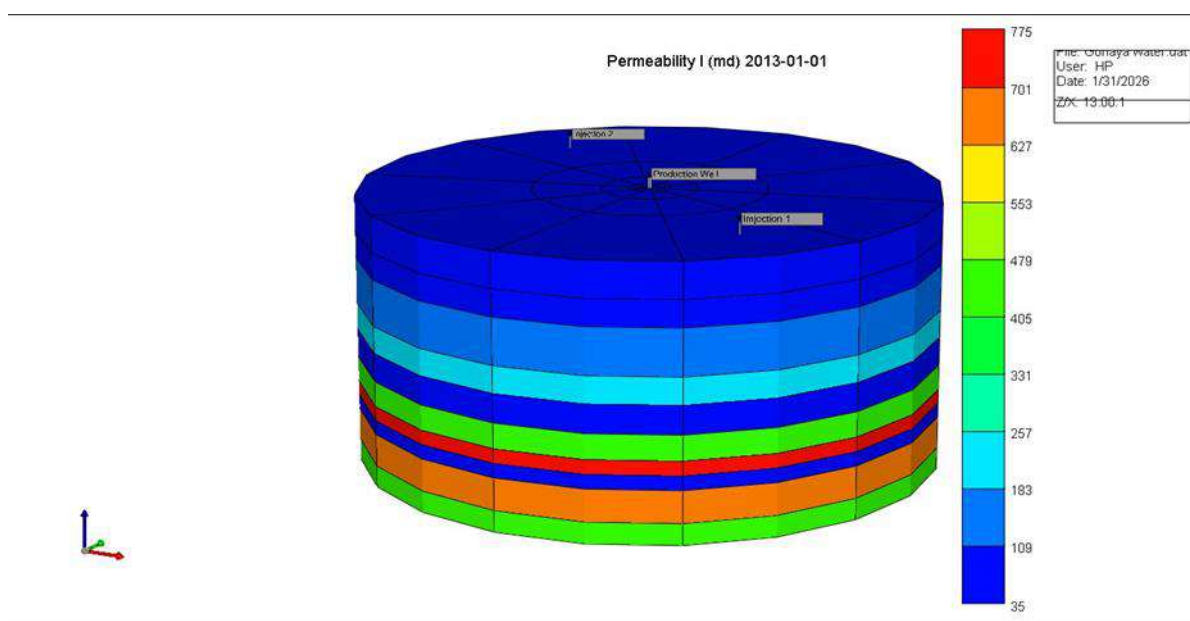


Figure 3-12: 3D view of injector wells

3.3.10 Simulation Time

The simulation period was set to 2 years (2013–2015) to evaluate reservoir performance.

Simulation Dates

* - no keyword data exists on this date (it can be deleted)

#	Date & Time (day)	set STOP	Comments
1	* 2013-01-01 (0.00)	☐	
2	* 2013-02-01 (31.00)	☐	
3	* 2013-03-01 (59.00)	☐	
4	* 2013-04-01 (90.00)	☐	
5	* 2013-05-01 (120.00)	☐	
6	* 2013-06-01 (151.00)	☐	
7	* 2013-07-01 (181.00)	☐	
8	* 2013-08-01 (212.00)	☐	
9	* 2013-09-01 (243.00)	☐	
10	* 2013-10-01 (273.00)	☐	
11	* 2013-11-01 (304.00)	☐	
12	* 2013-12-01 (334.00)	☐	
13	* 2014-01-01 (365.00)	☐	
14	* 2014-02-01 (396.00)	☐	
15	* 2014-03-01 (424.00)	☐	
16	* 2014-04-01 (455.00)	☐	
17	* 2014-05-01 (485.00)	☐	
18	* 2014-06-01 (516.00)	☐	

Add a new date:

Add a range of dates:

Delete selected empty dates:

Delete all empty dates:

To limit output file size, limit grid output (with WSRF) to:

Do not limit grid output

☐ Remove existing keywords (WSRF) to limit grid output

Recommendations

Close

Figure 3-13: Simulation schedule

CHAPTER FOUR

RESULTS AND DISCUSSION

4.1 Oil Recovery Factor

The oil recovery factors for the two recovery methods were compared, as shown in Figure 4-1.

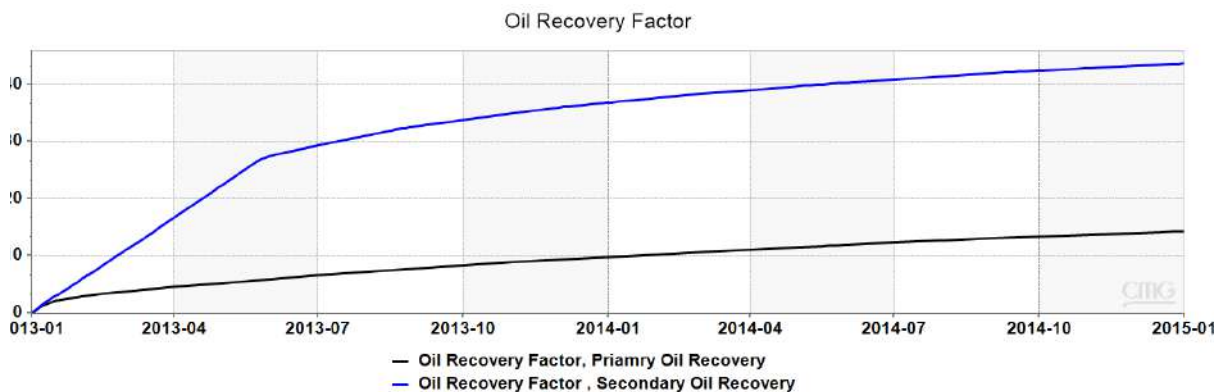


Figure 4-1: Oil Recovery Factor

The comparison includes primary oil recovery and secondary oil recovery using water injection. The results show that the oil recovery factor during primary oil recovery is relatively low. This is because primary recovery depends only on the natural energy of the reservoir to drive oil toward the production well. As production continues, reservoir pressure declines gradually, which reduces the driving force for oil flow and limits the amount of recoverable oil. On the other hand, the water injection process results in a significantly higher oil recovery factor compared to primary recovery. Injecting water into the reservoir helps maintain reservoir pressure and improves the displacement of oil toward the production well. The injected water sweeps the remaining oil more efficiently, leading to a noticeable increase in oil recovery.

The clear difference in oil recovery factor between the two cases highlights the effectiveness of water injection as a secondary recovery method in enhancing overall reservoir performance.

4.2 Oil Production Rate

The oil production rates for primary and secondary oil recovery using water injection are compared in Figure 4-2.

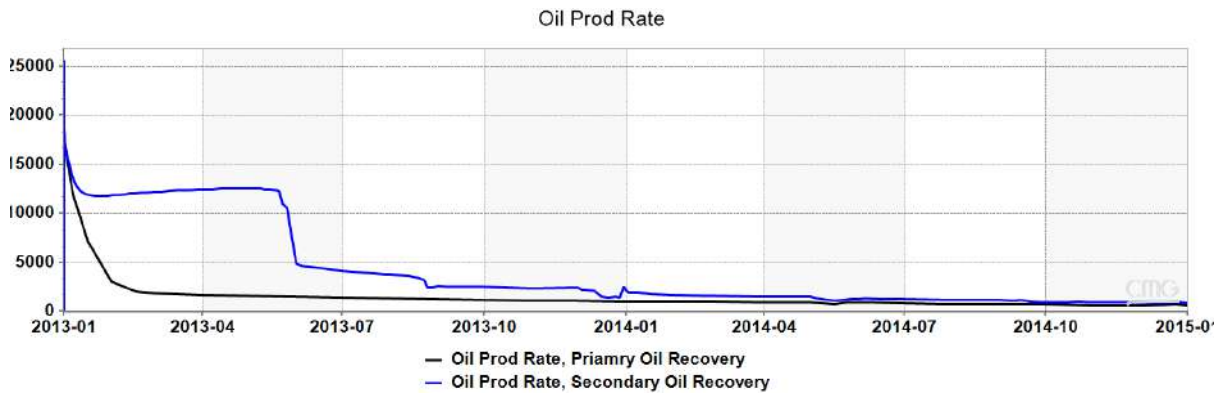


Figure 4-2: Oil Production Rate

The figure shows that during primary oil recovery, the oil production rate decreases rapidly with time. In the early stage of production, the oil rate is relatively high due to sufficient reservoir pressure. However, as production continues, the reservoir pressure declines, leading to a sharp reduction in oil production rate. This behavior reflects the limited driving energy available during primary recovery.

In contrast, the secondary oil recovery case with water injection maintains a higher oil production rate for a longer period. The injected water supports reservoir pressure and improves oil displacement toward the production well. Although fluctuations in the oil production rate are evident, the overall production level remains significantly higher than in the primary recovery case.

The comparison clearly indicates that water injection plays an important role in sustaining oil production rates and reducing the rapid decline observed during primary oil recovery.

4.3 Oil Production Cumulative

The cumulative oil production for primary and secondary oil recovery using water injection is compared in Figure 4-3.

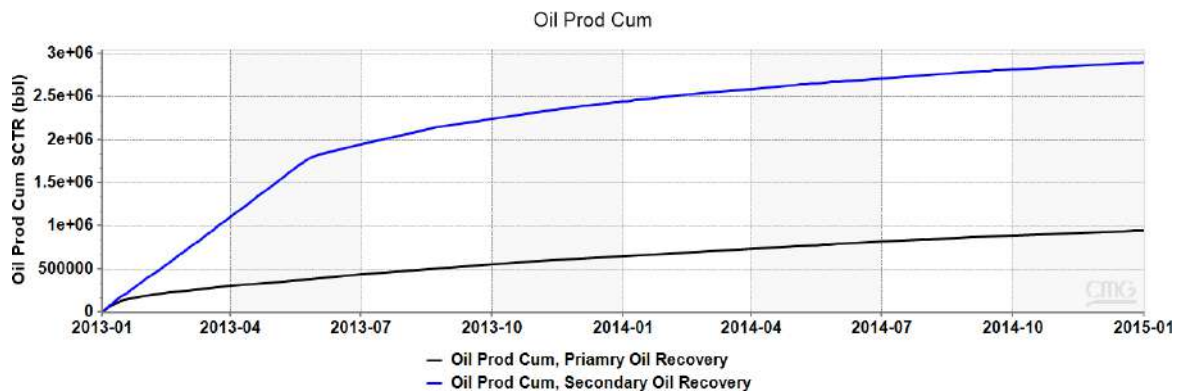


Figure 4-3: Oil Production Cumulative

The results show that the primary oil recovery case produces a relatively low cumulative oil volume over the production period. This is mainly due to the rapid decline in oil production rate caused by the continuous depletion of reservoir pressure. As pressure decreases, the reservoir's ability to deliver oil to the production well diminishes, resulting in lower cumulative production. In contrast, the secondary oil recovery case with water injection exhibits a significantly higher cumulative oil production. The injected water helps maintain reservoir pressure and improves oil displacement efficiency, allowing a larger volume of oil to be produced over time. The cumulative production curve for water injection shows a steeper increase, especially during the early and middle production stages. The comparison clearly demonstrates that water injection substantially enhances cumulative oil production compared to primary recovery, confirming its effectiveness as a secondary recovery method.

4.4 Oil Average Saturation

The variation of average oil saturation for both primary oil recovery and secondary oil recovery using water injection is presented in Figure 4-4.

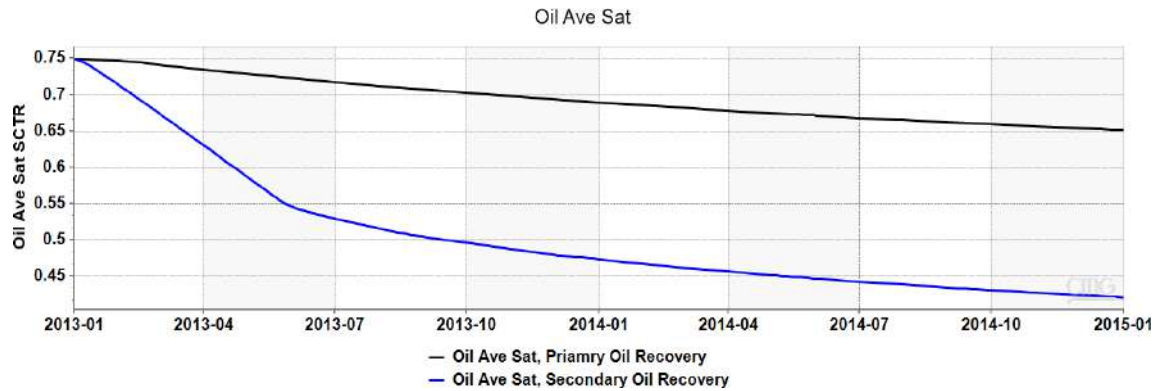


Figure 4-4: Oil Average Saturation

The figure shows that during primary oil recovery, the average oil saturation decreases gradually with time. This gradual reduction occurs because oil is produced mainly due to natural reservoir energy, while a large portion of oil remains trapped in the reservoir due to insufficient displacement efficiency.

In contrast, the secondary oil recovery case with water injection shows a much faster and more significant decrease in average oil saturation. The injected water effectively displaces oil from the pore spaces and pushes it toward the production well. As a result, more oil is removed from the reservoir, leading to a lower remaining oil saturation compared to primary recovery.

The clear reduction in oil average saturation during water injection confirms the improved sweep efficiency and enhanced oil displacement achieved by the secondary recovery process.

4.5 Gas Production Cumulative

The cumulative gas production for both primary oil recovery and secondary oil recovery using water injection is illustrated in Figure 4-5.

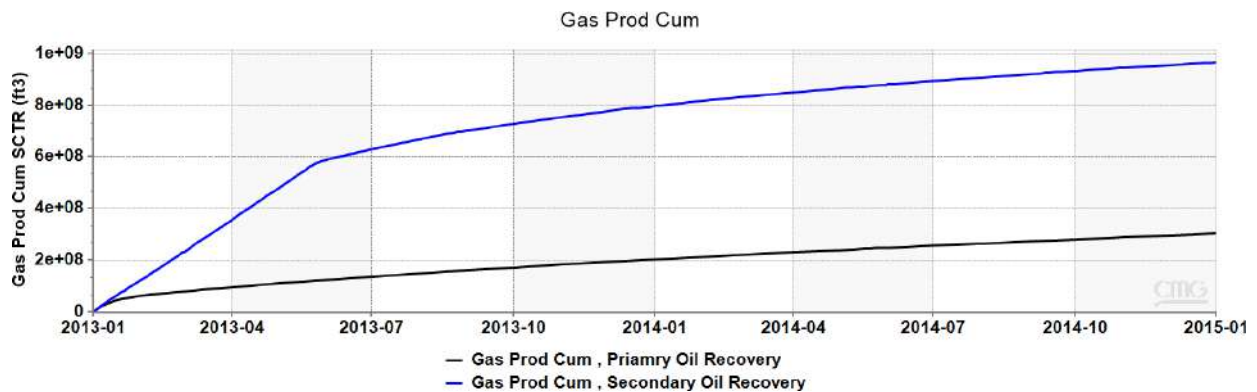


Figure 4-5: Gas Production Cumulative

The figure indicates that during primary oil recovery, the cumulative gas production increases gradually over time. Gas production in this case is mainly associated with pressure depletion in the reservoir, where dissolved gas is released from the oil as reservoir pressure declines below the bubble point.

In contrast, the secondary oil recovery case with water injection shows a significantly higher cumulative gas production. Water injection helps maintain reservoir pressure and improves oil displacement; however, gas production still occurs due to the movement of fluids and pressure redistribution within the reservoir. The higher cumulative gas production is also related to increased oil production, which leads to a greater amount of associated gas being produced.

The results demonstrate that water injection not only enhances oil recovery but also affects gas production behavior, resulting in higher cumulative gas production compared to primary recovery.

4.6 Water Cut

The variation of water cut for both primary oil recovery and secondary oil recovery using water injection is shown in Figure 4-6.

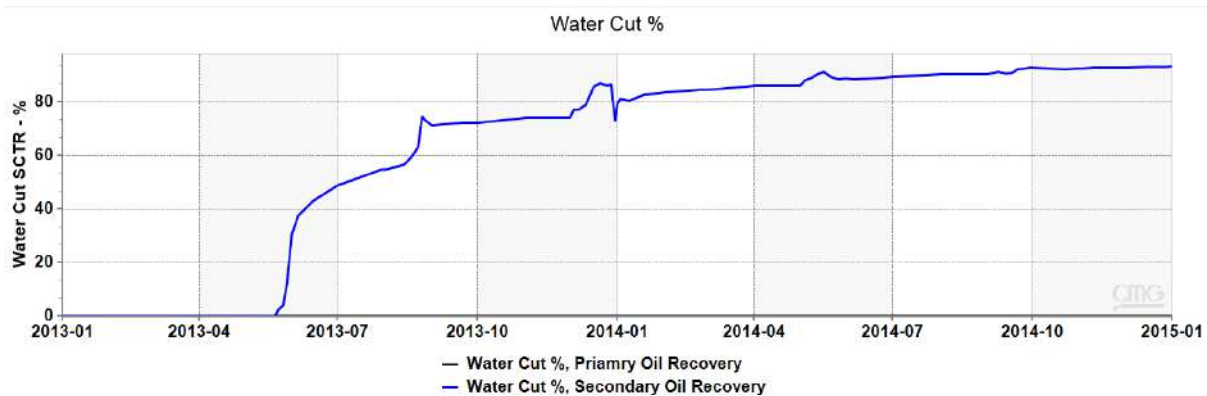


Figure 4-6: Water Cut

The figure indicates that during primary oil recovery, the water cut remains very low throughout the production period. This behavior is expected since no water injection is applied, and water production is mainly limited to the initial formation water present near the production well.

In contrast, the secondary oil recovery case with water injection shows a significant increase in water cut with time. After the start of water injection, water breaks through to the production well, leading to a rapid rise in water cut. As water injection continues, a larger fraction of the produced fluid becomes water, resulting in high water cut values.

The increase in water cut during water injection is a natural consequence of improved reservoir sweep and water movement toward the production well. This behavior confirms the effectiveness of water injection in displacing oil, despite the associated increase in produced water.

4.7 Water Volume

The cumulative produced water volume for both primary oil recovery and secondary oil recovery using water injection is presented in Figure 4-7.

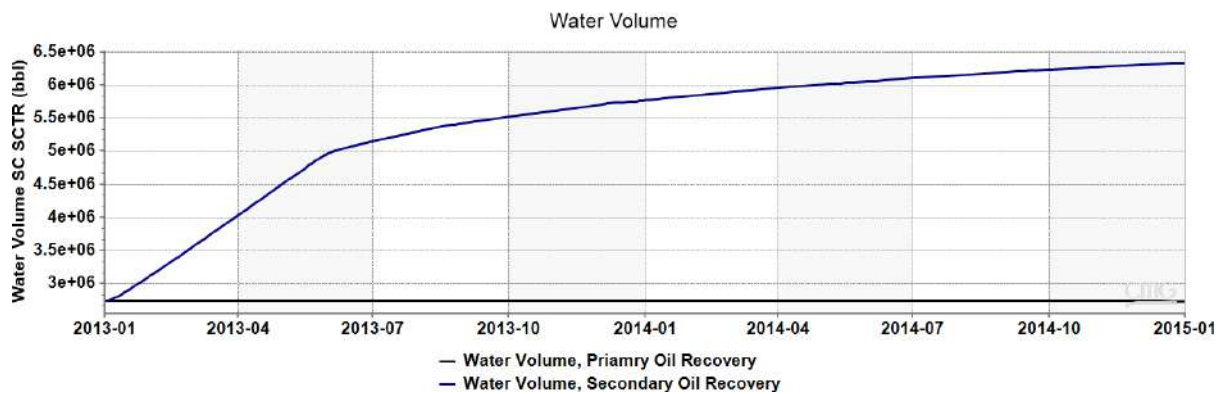


Figure 4-7: Water Volume

The figure shows that during primary oil recovery, the produced water volume remains very low throughout the production period. This is because no water injection is applied, and water production is limited to the initial formation water present in the reservoir.

In contrast, the secondary oil recovery case with water injection exhibits a significant increase in produced water volume over time. As water is continuously injected into the reservoir to maintain pressure and displace oil, a portion of the injected water eventually reaches the production well and is produced.

The steady increase in water volume is an expected result of the water injection process and indicates effective water movement and reservoir sweep. Although higher water production is observed, it is accompanied by improved oil recovery, which demonstrates the overall benefit of water injection in enhancing reservoir performance.

4.8 Water Average Saturation

The variation of average water saturation for both primary oil recovery and secondary oil recovery using water injection is illustrated in Figure 4-8.

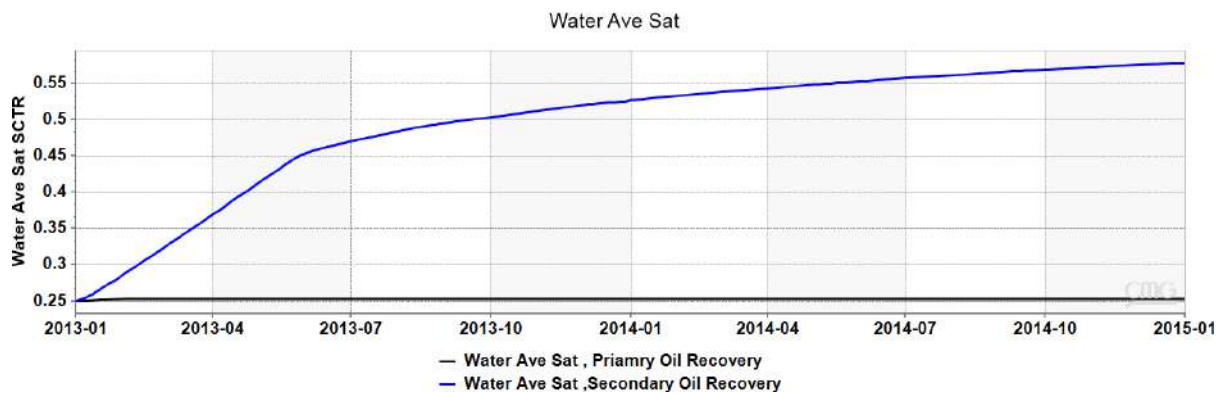


Figure 4-8: Water Average Saturation

The figure shows that during primary oil recovery, the average water saturation remains nearly constant throughout the production period. This behavior is expected since no water injection is applied, and the water present in the reservoir is mainly immobile formation water.

In contrast, the secondary oil recovery case with water injection exhibits a continuous increase in average water saturation over time. As water is injected into the reservoir, it progressively occupies more pore space, displacing oil toward the production well. This results in a higher water saturation compared to the primary recovery case.

The increase in water average saturation confirms the advancement of the water front within the reservoir and demonstrates the effectiveness of water injection in enhancing oil displacement and improving overall reservoir performance.

CHAPTER FIVE

CONCLUSIONS AND RECOMMENDATIONS

5.1 Conclusions

Based on the results obtained from the reservoir performance simulation using CMG-IMEX for a single oil well, the following conclusions can be drawn:

The simulation results showed that primary oil recovery alone leads to limited oil recovery, mainly due to the continuous decline in reservoir pressure with time.

The introduction of water injection as a secondary recovery method significantly improved reservoir performance, as reflected by the increase in oil recovery factor and cumulative oil production.

Water injection helped maintain reservoir pressure, which reduced the rapid decline in oil production rate observed during primary recovery.

The cumulative oil production in the water injection case was substantially higher than that of the primary recovery case, confirming the effectiveness of pressure maintenance and improved oil displacement.

The decrease in average oil saturation and the increase in average water saturation during water injection indicate improved sweep efficiency and successful displacement of oil from the reservoir.

Water cut and produced water volume increased during secondary recovery, which is a natural consequence of water injection, but this increase was accompanied by enhanced oil recovery.

Overall, the results demonstrate that water injection is an effective secondary recovery technique for improving oil recovery and extending the productive life of the reservoir.

5.2 Recommendations

Based on the findings of this study, the following recommendations are suggested for future work:

- Applying the simulation approach to real field data to better represent actual reservoir conditions.
- Studying the effect of different water injection rates and injection patterns on reservoir performance.
- Including economic evaluation to assess the feasibility of water injection projects.
- Investigating other recovery methods such as gas injection or enhanced oil recovery (EOR) techniques to further improve oil recovery.
- Considering reservoir heterogeneity in more detail to better understand its impact on fluid flow and sweep efficiency

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**Republic of Iraq
Ministry of Higher Education
and Scientific Research
University of AL-Kitab
College of Engineering**



Estimation initial oil in place by using Mbal software in one Iraq oil field

A Project

**Submitted to the Petroleum Engineering Department at
University of AL-Kitab as a Partial Fulfillment of the
Requirements of
the Degree of Bachelor of Science
in Petroleum Engineering**

BY

**Mhammed Tahrer Ahmed
Abdull Mohaimn Mohammed Farhan
Asil Jaber Salim**

Supervisor

Dr. Adnan Ajm

2025 / 2026

Abstract

Estimation initial oil in place by using Mbal software in one Iraq oil field is an essential aspect of oil and gas field development planning and reserves estimation, as it provides insight into the future behavior of the reservoir. The success of reservoir production depends on an accurate representation of reservoir rock properties, fluid properties, rock–fluid interactions, and overall flow performance. Therefore, petroleum engineers must possess a thorough understanding of reservoir characteristics, production optimization techniques, and, more importantly, the ability to develop analytical models that adequately describe the physical processes occurring within the reservoir system.

Reservoir performance prediction based on material balance equations has been widely discussed by several authors such as Morris Muskat, Craft and Hawkins, Tarner, Havlena and Odeh, Henry Tracy, and Schilthuis. These approaches form the theoretical foundation for predicting reservoir performance under different operating conditions.

In this study, reservoir reserves estimation is carried out using both dynamic simulation and predictive material balance methods after achieving a satisfactory history match. The analysis is performed using MBAL software to evaluate its capability in history matching and forecasting reservoir performance. The objective of this work is to establish a reliable reservoir model and to compare different modeling techniques and algorithms through case study validation.

Field data, including PVT analysis, production data, and well performance information, are collected and analyzed to ensure data quality and

consistency with physical reservoir behavior using appropriate correlations. History matching is conducted to align model predictions with actual reservoir conditions, particularly in estimating original oil in place and aquifer size.

The results obtained from various plots and parameter relationships demonstrate good agreement between history-matched data and simulation outcomes. Furthermore, future performance predictions show consistency between material balance and simulation approaches, confirming the reliability of the integrated modeling technique for carbonate reservoir performance evaluation and forecasting

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List of Nomenclatures And Abbreviations

Symbols	Description
k	permeability, md
K	absolute permeability
P_{BH}	bottom hole well flowing pressure
q	flow rate, bb1/day
r_e	effective well radius, ft
r_{ow}	wellbore radius, ft
W_{ei}	initial amount of encroach able water
$We(tdj)$	cumulative water influx at time (tdj)
μ	viscosity, cp
$(\Delta W_e)_n$	the incremental water influx in the interval Δt_n
C_o	Oil compressibility
C_f	Formation compressibility
B_o	Oil formation volume factor
B_g	gas formation volume factor

B_{oi}	Initial Oil formation volume factor
B_{gi}	Initial Gas formation volume factor
B_w	water formation volume factor
N	Initial oil in place
N_p	Produced oil
R_p	Gas solubility produced
R_s	Gas solubility at pressure
W_{inj}	Water injection
G_{inj}	Gas injection

Chapter one

1.1 Introduction

Some of the primary responsibilities of reservoir engineers include estimating hydrocarbon reserves, planning field development strategies, and optimizing production operations. Achieving these objectives requires a comprehensive understanding of reservoir characteristics and fluid flow behavior. More importantly, reservoir engineers must develop mathematical models capable of representing the physical processes occurring within the reservoir, allowing prediction of reservoir performance within acceptable engineering accuracy.

According to Morris Muskat (1945), one of the key roles of reservoir engineers is to predict the past performance of a reservoir which is still in the future. This statement highlights an important principle in reservoir engineering: regardless of the assumptions made by engineers, the reservoir itself always reflects the true behavior. Therefore, reservoir models must be continuously updated and calibrated based on actual production data, since reservoirs rarely behave exactly as predicted.

Accurate prediction of future production rates under varying operating conditions is essential for evaluating the feasibility of oil and gas projects and optimizing reservoir performance. However, conventional methods such as deliverability analysis and classical material balance equations are often limited when complete reservoir data are unavailable.

Reservoir performance refers to the ability of a reservoir to produce hydrocarbons over its lifetime, both in terms of total recovery (recovery factor) and the rate of production decline. The main objective in reservoir management is to maximize hydrocarbon recovery while minimizing the decline rate to ensure economic viability. To achieve accurate performance prediction, several key factors must be considered, including reservoir drive mechanisms, pressure behavior (static and dynamic), pore volume geometry, water saturation, and reservoir extent.

Reservoir performance prediction is inherently an iterative process. It involves continuous updating of the model until a satisfactory history match between calculated and observed production data is achieved. This process must be efficient to support timely decision-making in reservoir management and field development planning.

Several analytical methods based on the material balance concept are commonly used for predicting reservoir performance without resorting to complex numerical simulation. These include the methods developed by Henry Tracy, Morris Muskat, G. Tarner, and Schilthuis. These approaches rely on combining material balance equations with fluid properties such as gas-oil ratio (GOR) and saturation relationships. Calculations are typically performed over a range of assumed reservoir pressure declines and are often referenced to stock-tank oil initially in place at bubble-point pressure. Above the bubble point, cumulative oil production can be directly estimated using standard material balance formulations.

1.2. Study Area

Buzurgan Oil Field is located in the Missan province in southeastern Iraq, approximately 175 km north of Basra, near the Iraq–Iran border. The structural trend of the field is northwest–southeast, parallel to the Zagros Mountains, extending To 40 km in length and 7 km in width, with a total anticline area of approximately 394 km².

Buzurgan is considered one of the most significant oil fields in southern Iraq. The main producing reservoir is the Mishrif Formation (Cenomanian–Early Turonian). The first exploratory well, BU-1, was drilled in June 1969 to a total depth of 4298 m, confirming the presence of commercially viable hydrocarbons. Production from the field began in 1976. A 2D seismic survey was conducted between 1974 and 1977 to define structural boundaries, followed by a 3D seismic survey in 2013 to enhance reservoir characterization.

1.3. Objective of the Study

The main objective of this study is to maximize hydrocarbon recovery (recovery factor) while minimizing the production decline rate throughout the reservoir life to ensure economic sustainability.

In this project, an Integrated Production Modeling (IPM) approach developed by Petroleum Experts is utilized. This approach is based on material balance principles to forecast reservoir performance. Compared to full-scale reservoir simulation, which requires detailed geological modeling, fluid characterization, and comprehensive historical data integration, the IPM approach provides a more practical and efficient alternative for performance prediction, especially when data availability is limited.

Chapter Two

Literature review

2.1 Carbonate Reservoirs

A significant proportion of the world's oil reserves are found in carbonate reservoirs. Many of these are located in the Middle East, Libya, Russia, Kazakhstan, and North America. Some very large oil fields have carbonate reservoirs, including the largest conventional oil field in the world, the Ghawar field of Saudi Arabia.[3]

The reason for the very large size of some carbonate reservoirs is not surprising when one considers the sheer scale of even modern-day carbonate settings. The shallow submerged platform area of the Bahamas extends more than 400 km (248 mi) north–south and covers an area of about 125,000 km² (48,263 mi²). The size of individual sediment bodies on the Bahama Banks can be impressive too (Figure 1). The Joulter's Cay ooid shoal is a single carbonate sand body with a mobile border 25 km (15 mi) long and between 0.5 and 2 km (0.3 and 1.2 mi) wide. [4]

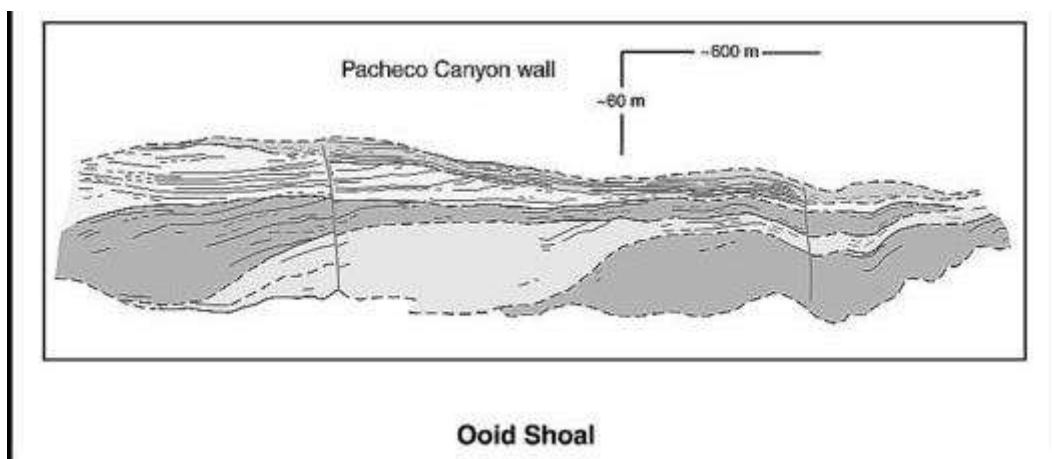


Fig. (2.1): Carbonate Reservoir (Management_ A Team Approach-Pennwell Books (1994).pdf.)

Carbonate sediments have several features that set them apart by comparison with siliciclastics. Carbonate sediments tend to form and be deposited in situ, with enormous volumes of calcareous material provided by the death, disintegration, or digestion of plant and animal matter. The coarser material tends not to be widely spread or abraded by waves and currents. Consequently, uniform grain sorting is not a major characteristic of carbonates. There can be a great diversity of grain sizes and shapes in most carbonate sediments compared to sandstones.

There are some similarities to siliciclastic environments. Various sedimentary bodies such as beaches, barrier islands, shelf sediments, gravity flows, and dune sands are also found in carbonate settings.[5]

Carbonate reservoirs can be difficult to develop for a variety of reasons. They generally have poorer recoveries than siliciclastic sediments (e.g., Sun and Sloan).^[4] A combination of depositional geometry and diagenesis creates highly heterogeneous reservoirs (Table 1). They can have lower primary recoveries as connected volumes may be areally limited with no contact to a large aquifer. The lower energy drive mechanisms such as solution gas drive are common. Heterogeneity at all the reservoir scales can make them a challenge to model, and it is not an easy task to make reliable predictions about their production performance. Reservoir management is difficult because the accurate targeting of production and injection wells is problematic, and sweep may be inefficient as a result of this. Pore sizes in carbonates vary from micron scale to cave systems. Carbonates with vuggy porosity can store significant volumes of oil, yet sometimes the vugs are largely unconnected, yielding low flow rates. Tiny pores on a micron scale can form a high component of the porosity. The porosity may look impressive on logs, yet much of this may be microporosity and unproduceable.[6]

The petrophysical analysis of carbonate reservoirs is difficult and prone to greater uncertainty than with sandstone reservoirs. The uncertainty in the determination of water saturation, effective porosity, net pay, and permeability will impact the estimation of in-place volumes and reserves. Carbonates have a tendency to oil-wet characteristics or show mixed wettability. Typical behavior in oil-wet systems includes early water breakthrough and high water production rates. Carbonates can have thick transition zones in reservoirs with low matrix permeability . Residual oil saturations can also be high [7].

Carbonates are typically brittle rocks and are commonly fractured. The fractures can be a major component of the field performance, enhancing effective permeability and creating connectivity within otherwise heterogeneous reservoirs. Fractures will influence sweep patterns and will cause considerable variability in well-flow rates. Thief zones in fractures and high-permeability

Table 1 Factors influencing connectivity and reservoir development in carbonate reservoirs.

Characteristic	Favorable for Reservoir Development	Unfavorable for Reservoir Development
Carbonates form highly heterogeneous reservoirs		Generally have lower recoveries than sandstone reservoirs; difficult to locate wells
Generally do not have large aquifers		Poor primary recoveries
Tend toward oil-wet behavior		Early water breakthrough and high water production rates
Brittle rocks and commonly fractured	Fractures can create widespread connectivity in an otherwise heterogeneous matrix rock	Can form thief zones with rapid water breakthrough
Common high-frequency cycles on a meter scale		Numerous hydraulic units and highly layered reservoirs
Shingled geometries can be present		Potential to create bypassed oil volumes, particularly in shingled oolites
Diagenesis can significantly modify the original depositional connectivity in carbonate sediments	Dolomitization can potentially create good connectivity by modifying fine-grained sediments	Pervasive cements can significantly reduce rock properties and connected volumes

intervals can cause early water breakthrough.[8]

2.2. Rock types in carbonates

It is an established procedure to characterize the rock properties of carbonates by rock types instead of lithofacies [9]. These are textural classes that are related to both depositional and diagenetic processes. Sandstone rock properties are dominated by intergranular pore systems, which exhibit a strong lithofacies control on grain size, shape, and sorting. By contrast, carbonate pore systems are much more complex. The primary intergranular porosity is more variable because of the greater range in grain sizes and shapes. In addition, skeletal materials common in carbonates will show intraparticle porosity. The primary rock texture will often then be overprinted by postdepositional leaching, replacement, and cementation to form an even more complex pore network. [10]

2.3 Previous Studies:

There are some of studies that have been developed to study the reservoir performance prediction we show some of it:

Okotie Sylvester,2015 develop a mathematical model that will adequately depict the physical processes occurring in the reservoir such that the outcome of any action can be predicted within reasonable tolerance of errors. In his study, software “REPAT” was built based on material balance and an expansion of Tarner’s method by incorporating water influx and time concept to the material balance equation. The history matching process consists of modifying the aquifer parameters until an acceptable match was obtained within engineering accuracy [11].

Irero Idogun,2015 compares reserves estimation using predictive material balance and dynamic simulation after history matching both models. Results

shows that for multi-tank modeling using of hydraulically connected reservoirs using MBAL, transmissibility modeling & aquifer modelling are key factors in achieving reasonably reliable MBAL models. A good understanding of the reservoir fault frame work and connectivity, adequate & reliable BHP, injection and production data are very important for attaining a good history match & model calibration. Results of this study show a good comparison between the Reserves estimate from both MBAL and that from dynamic simulation. Under the appropriate conditions, Predictive Material Balance is a quick alternative tool to reservoir simulation in reservoir performance prediction especially when time & resources are limited. Also, predictive material balance analysis should be applied in reservoir where the existing wells have adequate data to build reliable inflow & out flow models.[12]

J. O. Ayorinde, 2019 illustrated Two producing reservoirs (H10 and E40) in Eni field Offshore Niger Delta were studied with intent to enhance their rate of recovery while mitigating water production. The material Balance software MBAL was used to estimate the Stock tank oil reserves and then compared to reserve estimates determined by both deterministic and stochastic techniques for improved validation. The MBAL model was also used to identify positions of fluid contacts and determine predominant drive mechanisms. These serve as guide in making informed decisions towards if and how best to economically produce remaining unproduced oil in place. Input parameters were average values

derived from core and well logs analyses. History matching of historical data enabled forecasts of possible future production life and volume at multiple scenarios. Final outcomes show that after sixteen and forty five years of continuous production from the reservoirs studied (H10 and E40, respectively), remaining unproduced oil in place are still significant and can be economically produced by infill wells, which will in return increase the average production by

nothing less than 33% of remaining oil in place, a substantial value bearing in mind the growing demand for oil, gas and other energy sources to lessen the apparently unquenchable world energy needs.[14]

Amarachi Uche Onuka, 2019 predicts the future performance of an oil reservoir with no initial gas cap, being produced by a strong underlying aquifer using the Schilthuis steady state and Hurst-Van Everdingen modified water influx models. The aim of this analysis is to highlight the discrepancies in the capabilities of the Schilthuis steady state water influx model and the Hurst-Van Everdingen modified model to effectively give the reservoir engineer a thorough understanding of the effects of aquifer influx into a reservoir on the cumulative oil production and estimation of oil-in-place. This was achieved by carrying out a simulation analysis using the Schilthuis steady state and the Hurst-Van Everdingen unsteady state models in the MBAL package to predict changes in the following reservoir parameters for a 20-year period. For the production period being analysed, the oil recovery factor was given as 26.76%. The difference in recoverable reserves estimated using the Schilthuis steady state and Hurst-Van Everdingen modified water influx models was 0.406738 MMSTB.[15]

Prathmesh Sapale, 2019 compares estimation of reserve using dynamic simulation in MBAL software and predictive material balance method after history matching of both of the model. Results from this paper shows functionality of MBAL in terms of history matching and performance prediction. The objective is to set up the basic reservoir model, various models and algorithms for each technique are presented and validated with the case studies. Field data collected related to PVT analysis, Production and well data for quality check based on determining inconsistencies between data and physical reality with the help of correlations. It shows history matching to match original oil in place and aquifer size. In the end conclusion obtained from

different plots between various parameters reflect the result in history match data, simulation result and Future performance of the reservoir system and observation of these results represent similar simulation and future prediction plots result.[16]

C. G. J. Nmegbu,2021 generated comparatively study the oil recovery factor from two major aquifer geometry (Bottom and Edge water aquifer) using water aquifer model owing to the fact that most if not every reservoir is bounded by a water aquifer with relative size content (Most Large). These aquifers are pivotal in oil recovery factor (percent%), Cumulative oil produced (MMSTB) as well as overall reservoir performance the methodology utilized in this study involves; Identification of appropriate influx models were utilized for aquifer characterization. The characterizes of the Niger Delta reservoir aquifer considered include aquifer permeability, aquifer porosity etc. Estimation of aquifer properties is achieved by using regressed method in Material Balance Software (MBAL). This approach involves History Matching of average reservoir pressure with computed pressure of the reservoir utilizing production data and PVT data. [17]

2.4 RECOVERY MECHANISMS:

2.4.1 PRIMARY RECOVERY MECHANISMS:

For a proper understanding of reservoir behavior and predicting future performance, it is necessary to have knowledge of the driving mechanisms that control the behavior of fluids within reservoirs. The overall performance of oil reservoirs is largely determined by the nature of the energy, i.e., driving mechanism, available for moving the oil to the wellbore. There are basically six driving mechanisms that provide the natural energy necessary for oil recovery [18]:

- Rock and liquid expansion drive
- Gas cap drive
- Gravity drainage drive
- Depletion drive
- Water drive
- Combination drive

These driving mechanisms are discussed as follows.

1. Rock and Liquid Expansion

When an oil reservoir initially exists at a pressure higher than its bubble-point pressure, the reservoir is called an undersaturated oil reservoir. At pressures above the bubble-point pressure, crude oil, connate water, and rock are the only materials present. As the reservoir pressure declines, the rock and fluids expand due to their individual compressibilities. The reservoir rock compressibility is the result of two factors [19]:

- Expansion of the individual rock grains
- Formation compaction

Both of the above two factors are the results of a decrease of fluid pressure within the pore spaces, and both tend to reduce the pore volume through the reduction of the porosity. As the expansion of the fluids and reduction in the pore volume occur with decreasing reservoir pressure, the crude oil and water will be forced out of the pore space to the wellbore. Because liquids and rocks are only slightly compressible, the reservoir will experience a rapid pressure decline. The oil reservoir under this driving mechanism is characterized by a constant gas-oil ratio that is equal to the gas solubility at the bubble point pressure. In the case of a volumetric reservoir with a heavy oil that is characterized by both; a low gas solubility and a low bubblepoint pressure, the reservoir driving mechanism for this type of reservoirs is considered the least efficient driving force and usually results in the recovery of only a small

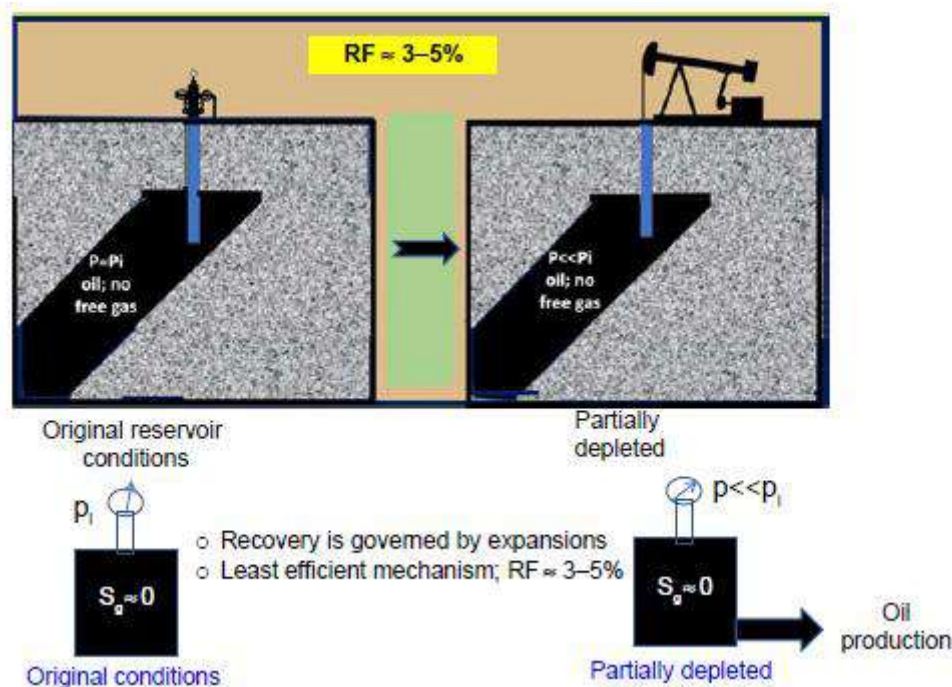
percentage of the total oil in place ranging between 3-5%. Figure 2-2, shows a conceptual illustration of the impact of the low gas solubility on the reservoir recovery performance.[20]

2. The Depletion Drive Mechanism

This driving form may also be referred to by the following various terms:

- Solution gas drive
- Dissolved gas drive
- Internal gas drive

In this type of reservoir, the principal source of energy is a result of gas liberation from the crude oil and the subsequent expansion of the solution gas as the reservoir pressure is reduced. As pressure falls below the bubble-point pressure, gas bubbles are liberated within the microscopic pore spaces. These bubbles expand and force the crude oil out of the pore space as shown



conceptually in Figure 2-2.

FIGURE 2-2 Oil reservoir under rock and fluid expansions driving mechanism.

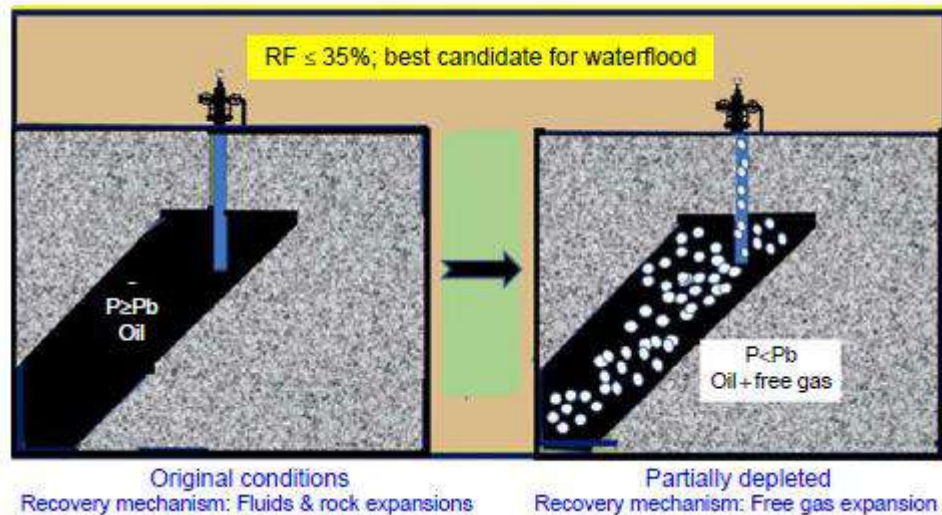


FIGURE 2-3 Solution gas-drive reservoir (22)

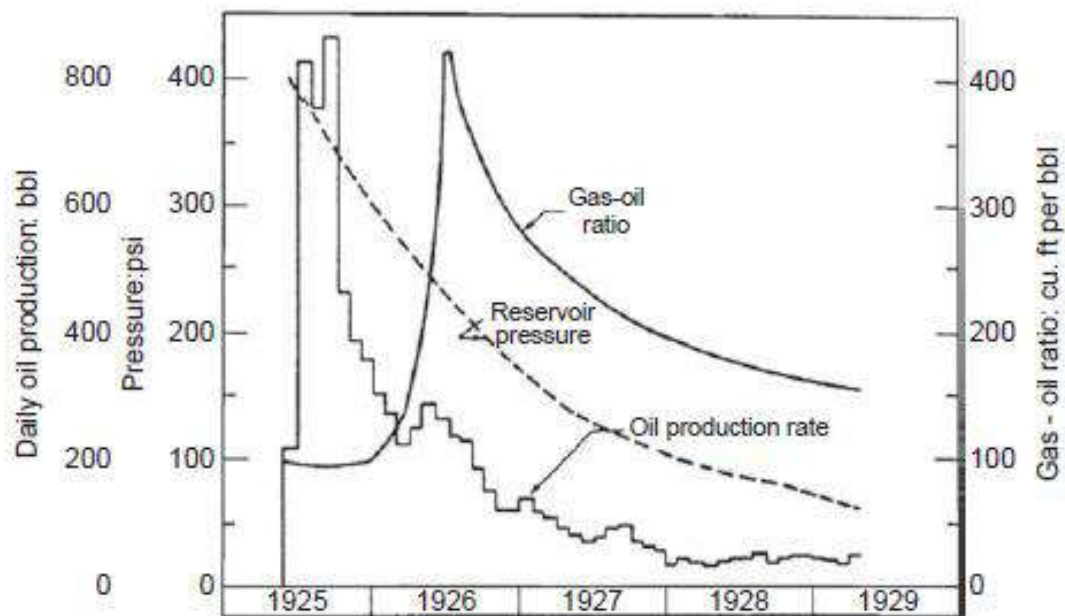
Cole (1969) suggests that a depletion-drive reservoir can be identified by the following characteristics [22]:

- **Reservoir pressure:** The reservoir pressure declines rapidly and continuously. This reservoir pressure behavior is attributed to the fact that no extraneous fluids or gas caps are available to provide a replacement of the gas and oil withdrawals.
- **Water production:** The absence of a water drive means there will be little or no water production with the oil during the entire producing life of the reservoir.
- **Gas-oil ratio:** A depletion-drive reservoir is characterized by a rapidly increasing gas-oil ratio from all wells, regardless of their structural position. After the reservoir pressure has been reduced below the bubble-point pressure, gas evolves from solution throughout the reservoir. Once the gas saturation exceeds the critical gas saturation, free gas begins to flow toward the wellbore and gas-oil ratio increases. The gas will also

begin a vertical movement due to the gravitational forces, which may result in the formation of a secondary gas cap. Vertical permeability is an important factor in the formation of a secondary gas cap.

- **Ultimate Oil Recovery:** Oil production by depletion drive is usually the least efficient recovery method. This is a direct result of the formation of gas saturation throughout the reservoir. Ultimate oil recovery from depletion-drive reservoirs may vary from between 20% and 35% based on the crude oil gas-solubility. The low recovery from this type of reservoirs suggests that large quantities of oil remain in the reservoir and, therefore, depletion-drive reservoirs are considered the best candidates for secondary recovery applications.

The above characteristic trends occurring during the production life of



depletion-drive reservoirs are shown in Figure 2-4 and summarized below [23]:

FIGURE 2-4: Production data of a solution-gas-drive reservoir.(23)

3. Gas Cap Drive

Gas-cap-drive reservoirs can be identified by the presence of a gas cap with little or no water drive as shown in Figure 2-5. Due to the ability of the gas cap to expand, these reservoirs are characterized by a slow decline in the reservoir pressure. The natural energy available to produce the crude oil comes from the following two sources [24]:

- Expansion of the gas-cap gas
- Expansion of the solution gas as it is liberated

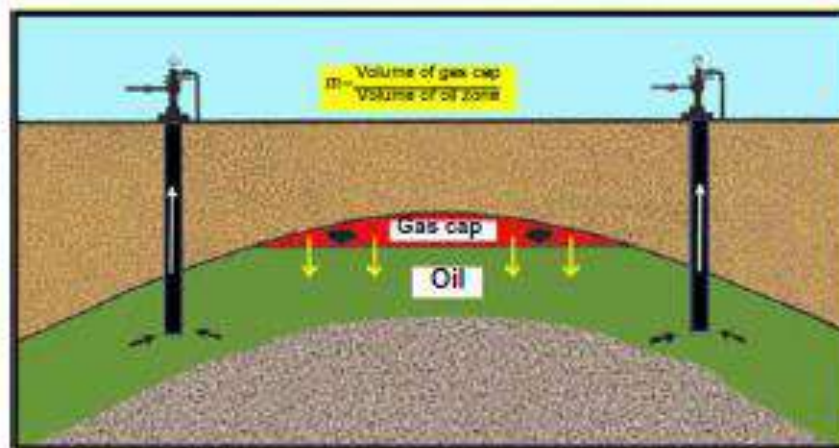


FIGURE 2.5: Gas-cap drive reservoir.(24)

4. The Water-Drive Mechanism

Many reservoirs are bounded on a portion or all of their peripheries by water bearing rocks called aquifers. The aquifers may be so large compared to the reservoir they adjoin as to appear infinite for all practical purposes, and they may range down to those so small as to be negligible in their effects on the reservoir performance.

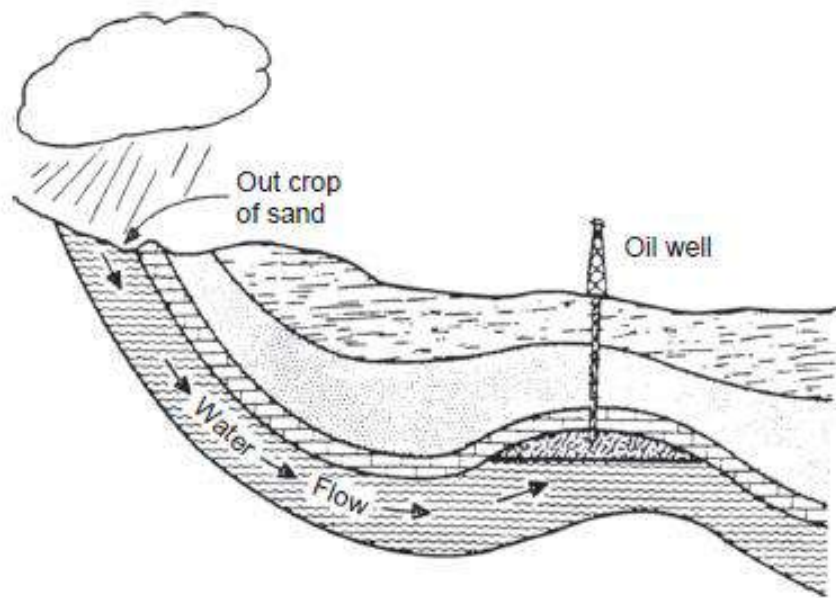


FIGURE 2.6: Reservoir having artesian water drive.(25)

The aquifer itself may be entirely bounded by impermeable rock so that the reservoir and aquifer together form a closed (volumetric) unit. On the other hand, the reservoir may be outcropped at one or more places where it may be replenished by surface water as shown schematically in Figure 2.6. It is common to speak of edge water or bottom water in discussing water influx into a reservoir. Bottom water occurs directly beneath the oil and edge water occurs off the flanks of the structure at the edge of the oil as illustrated in Figure 2.7. Regardless of the source of water, the water drive is the result of water moving into the pore spaces originally occupied by oil, replacing the oil and displacing it to the producing wells.[25]

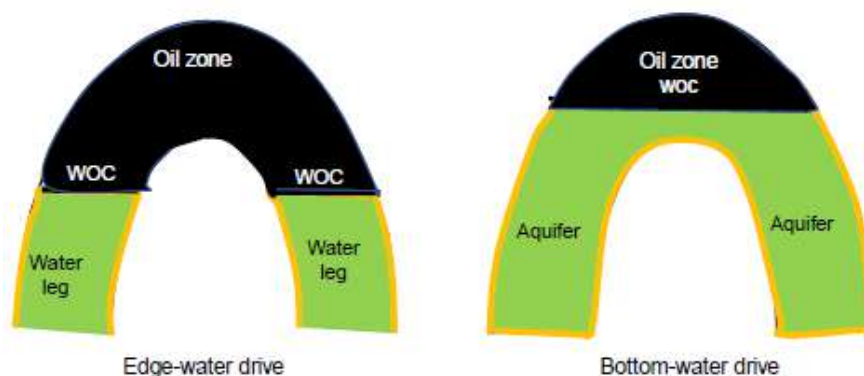


FIGURE 2.7: Edge and bottom-water drive.(25)

5. The Gravity-Drainage-Drive Mechanism

The mechanism of gravity drainage occurs in petroleum reservoirs as a result of differences in densities of the reservoir fluids. The effects of gravitational forces can be simply illustrated by placing a quantity of crude oil and a quantity of water in a jar and agitating the contents. After agitation, the jar is placed at rest, and the more denser fluid (normally water) will settle to the bottom of the jar, while the less dense fluid (normally oil) will rest on top of the denser fluid. The fluids have separated as a result of the gravitational forces acting on them. The fluids in petroleum reservoirs have all been subjected to the forces of gravity, as evidenced by the relative positions of the fluids, i.e., gas on top, oil underlying the gas, and water underlying oil. The relative positions of the reservoir fluids are shown in Figure 2.9. Due to the long periods of time involved in the petroleum accumulation-and-migration process, it is generally assumed that the reservoir fluids are in equilibrium. If the reservoir fluids are in equilibrium, then the gas-oil and oil-water contacts should be essentially horizontal. Although it is difficult to determine precisely the reservoir fluid contacts, best available data indicate that, in most reservoirs, the fluid contacts actually are essentially horizontal.[25]

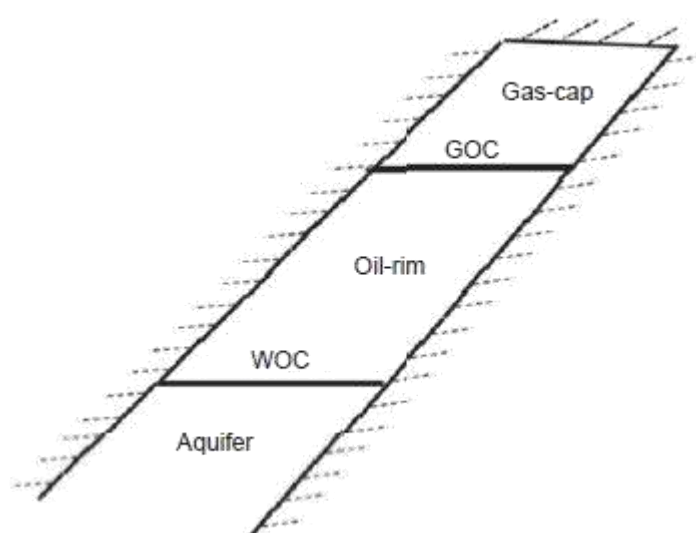


FIGURE 2.9: Initial fluids distribution in a combination-drive oil reservoir.(25)

2.5 Overview of the Reservoir:

The oil reservoir is under-saturated which possessed saturation pressure of 3200 psia, oil API gravity was 39, oil density 51.78 lb/ and rock compressibility is calculated based on the correlations. For described reservoir a single tank MBAL model was built. Aquifer influx modeled were checked from which a suitable match of reservoir trend was selected. The models used to match with the help of tuning and Regression method where pressure and Production data regressed. To build a reservoir model knowledge of the reservoir structure, aquifer support and Gas cap was necessary [22]. Those were identified based on available data which used to ensure good engineering judgment. The idea behind history matching was that the model input is adjusted to match the field pressure and production history data. Procedure should be a way of systematic where adjusting the reservoir model to agree with the field operation data. Encroachment angle and radius were regressed to obtain history matches on pressure and production data which ensure a satisfactory pressure match for the tank. In this study to get a quality history match, Different aquifer models were used in the reservoir model and their parameters were regressed [23].

Best fit aquifer was selected. This was observed when model and field pressure and production data matched together in graphical representation. In this study author find that there is no impedance between material balance and simulation, instead they were supportive of one another. Material balance is best for the history matching pressure and production performance but has disadvantage when it comes to prediction, which is strongly related to numerical reservoir simulation modelling. As in this case good history match had been achieved, MBAL model showed a good pressure and production match for the tank with historical production and pressure data. Further research shows performance prediction of the reservoir tank.

2.6 History matching

Once a reservoir simulation model has been constructed, the validity of the model is examined by using it to simulate the performance of a field under past operating conditions. This is usually done by specifying historical controlling rates, such as oil rate in an oil reservoir vs. time, and then making a comparison of the nonspecified performance such as gas/oil ratio (GOR), water/oil ratio (WOR), and reservoir pressure with measured data. If there are significant differences between the calculated performance and the known performance of the well/reservoir system, then adjustments to the reservoir simulation model are made to reduce this difference. This process is called History Matching.

2.6.1 History Matching Strategy for MBAL

MBAL's progressive menu options lead the engineer logically through the history matching process, which is performed graphically using industry standard techniques (e.g. Cole, Campbell, P/Z plots) and allows the identification of drive mechanisms in place, and whether the measured data entered is to be trusted. Having used the analytical methods available in MBAL to history match the analytical model, a simulation is run of the history, and yields two valuable results: Firstly, by running the historical period in a simulation, the user can compare the production profiles predicted from the model and the data entered (a close match indicating a good history match). Secondly, by running the history as a prediction, MBAL will calculate all the historical production profiles, saturations and reservoir pressures in the historical period. This can be used to create custom relative permeability curves and calibrate these to the History matched model. The historical data can be entered on a tank basis, or in a well by well basis, in the latter context the Relative Permeability curves can be generated for the draining area of each well

using the approach described above. It is this innovative capability that allows the analytical model to approach the response of reality and is a departure from classical literature based models.

2.6.2 Determination of the Matching Parameters

The initial approach was to use the simulator input data and afterwards to match the MBAL results with the observed data by altering the most uncertain variables. The reason behind the building of a single-tank model was to reduce the number of uncertainties; in fact, the number was shortened by discarding the transmissibility parameters. This gives an opportunity to estimate approximately the aquifer system parameters and afterwards to apply them in the multi-tank model construction.

The MBAL non-linear regression option can be used to optimize several parameters in one realization. However, caution needs to be taken because optimizing all uncertain parameters may give unrealistic results. Even uncertain parameters have their own degree of uncertainty, and for this reason it is crucial to determine a best set of variables.

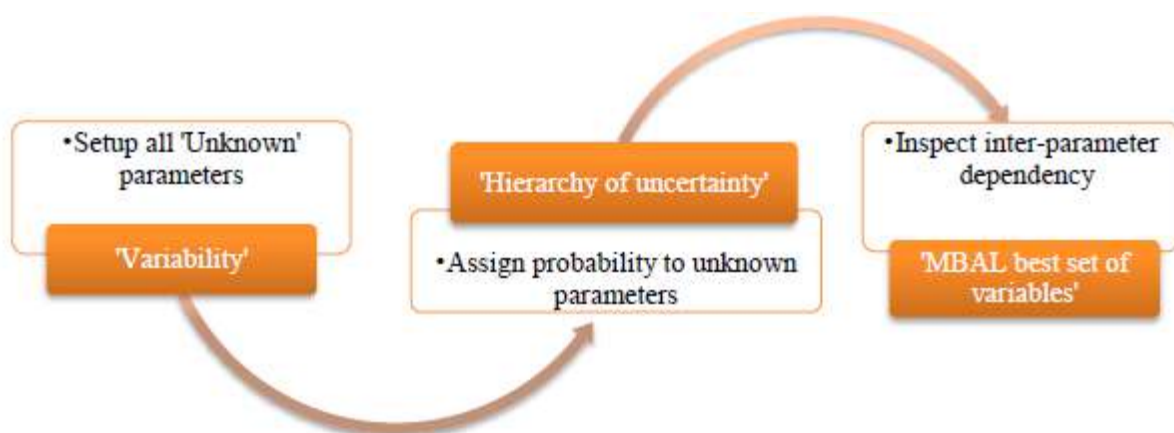


Figure 2.9: Workflow in determining matching parameters

As illustrated in Fig. 2.10, the determination of ‘MBAL best set of variables’ consists of three stages and the outcomes of each step are:

- Variability - establish all uncertain parameters;
- Hierarchy of uncertainty – consult with expert in order to assign the probability to each variable;
- MBAL best set of variables – examine inter-parameter dependency using related equation.

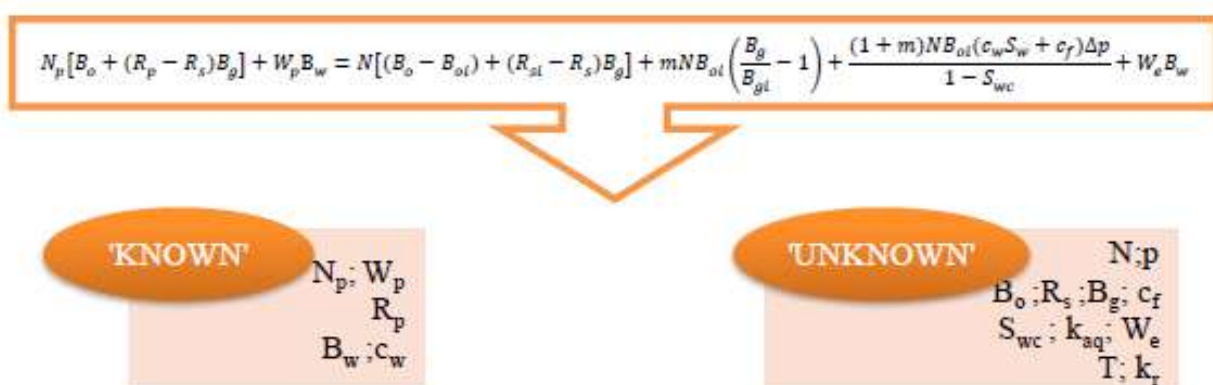


Figure 2.10 - Potential unknown parameters (Dake, 2001).

2.6.3 History matching parameters:

1. Analytical Method

The analytical history matching method of MBAL is a plot based technique which uses non-linear regression engine to assist in estimating unknown reservoir and aquifer parameters [13]. The program calculates the production of primary fluid based on the reservoir pressure and production of secondary fluids from the history entered. In this case secondary fluid is water. The program

regresses on the $S_o + S_g + S_w = 1$ equation. Errors in the material balance from the regression can be checked from the values in standard deviation. $(F - W_e)/(G * E) - 1 = 0$. A value less than 0.1 indicate an acceptable match. To fit an appropriate size aquifer, three different outer-inner radius ratios of red = 4, 5 and 6 were used in analytical history matching. Based on the seismic and geological evidence it is suspected that the value of red is less than 7.

2. Graphical Method

Once a quality match is observed in the analytical plot, the aquifer size can be confirmed with Havlena and Odeh's water drive plot (F/E_t vs W_e/E_t plot) in the graphical method of MBAL [13]. Deviation from the straight line in the upward or downward direction in F/E_t vs W_e/E_t plot indicates that the amount of water incorporated with the material balance is too small or too large respectively. Once the plot took a unit slope shape, the results of cumulative W_e calculated by the model is assumed appropriate.

3. History Simulation

History simulation of MBAL is used to perform the final quality check on the history matching carried with the graphical and analytical methods. History simulation method does the opposite of analytical method. It calculates reservoir pressures using the historical production data based on the reservoir and aquifer model [13].

Chapter Three

Theoretical Background

3.1 Reservoir Performance Analysis

Recovery of hydrocarbons from a reservoir may make exclusive use of the inherent energy of the *system* (primary recovery); energy may be added to the system in the form of injected fluids (secondary recovery); some of the residual hydrocarbon trapped during *conventional* recovery processes may be mobilized (tertiary or enhanced oil recovery).[26]

3.2.1 PRIMARY RECOVERY IN OIL RESERVOIRS

Oil can be recovered from the pore spaces of a reservoir rock by expansion or only to the extent that the volume originally occupied by the oil is invaded or occupied in some way. There are several ways in which oil can be produced from a reservoir, and these may be termed mechanisms or *drives*, and where one replacement mechanism is dominant, the reservoir may be said to be operating under a particular *drive*. The analysis of drive mechanisms using a method of material balance follows the general form described by Schilthuis [30]. Possible sources of replacement for produced fluids are:

- (a) expansion of undersaturated oil above the bubble-point;
- (b) the release of gas from solution in the oil at and below the bubble-point;
- (c) invasion of the original oil-bearing reservoir by gas from a free gas cap;
- (d) invasion of the original oil-bearing reservoir by water from an adjacent or underlying aquifer.

All replacement processes involve a reduction in pressure in the original oil zone, although pressure drops may be small if gas caps are large, and aquifers

large and permeable, and pressures may stabilize at constant or declining reservoir offtake rates under favourable circumstances. The compressibility of oil, rock and connate water is generally relatively small, so that pressures in undersaturated oil reservoirs will fall rapidly to the bubble-point if there is no aquifer to provide water drive. As a result, these expansion mechanisms are not usually considered separately, and the three principal categories of reservoir drive are:

- (1) solution gas drive (or depletion drive) reservoirs;
- (2) gas cap expansion drive reservoirs;
- (3) water drive reservoirs.

Frequently two or all three mechanisms (together with rock and connate water expansion) may occur simultaneously and result in a combination drive.[31]

3.2.2 Solution gas drive: analysis by material balance

If a reservoir at its bubble-point is put on production, the pressure will fall below the bubble-point pressure and gas will come out of solution. Initially this gas may be a disperse discontinuous phase, essentially immobile, until some minimum saturation - the equilibrium, or critical gas, saturation – is attained. The actual order of values of critical saturation are in some doubt, but there is considerable evidence to support the view that values may be very low - of the order of 1 % to 7% of the pore volume [32]. At early times, as pressure declines and gas comes out of solution, but cannot flow to producing wells, the producing GOR will decline. When the critical gas saturation is established and if the potential gradients permit, gas will flow towards producing wells. The permeability to oil will become lower than at initial conditions, and there will be a finite permeability to gas so that the producing gas-oil ratio will rise. As more

gas comes out of solution, and gas saturations increase, permeability to gas increases, permeability to oil diminishes and this trend accelerates. Ultimately, as reservoir pressure declines towards abandonment pressure, the change in gas formation volume factor offsets the increasing gas to oil mobility ratio, and the gas-oil ratio trend is reversed, i.e. although the reservoir GOR may continue to increase in terms of standard volumes, the ratio standard cubic ft/stock tank barrel may decline. The analysis of performance of a solution gas drive reservoir can be conducted by use of reservoir condition material balance, or volumetric balance techniques. The methods consider a number of static equilibrium stages of reservoir production during which pressure changes have occurred, At any equilibrium stage a balance is made on the original reservoir content at original pressure and the current reservoir content at current pressure. For oil production of an undersaturated reservoir from P_i down to bubble-point pressure P_h , the solution gas-oil ratio remains constant in the reservoir [33]. A reservoir condition volumetric balance is Thus The net influx terms are represented by W_e' . The balance therefore becomes:

$$N_p \{B_o + (R_p - R_s)B_g\} = N(B_{oi}) \left\{ \frac{B_o - (B_{oi})}{(B_{oi})} + \frac{(R_{si} - R_s)B_g}{(B_{oi})} + \Delta P \frac{(C_w S_{wi} + C_f)}{1 - S_{wi}} \right\} W_e \quad (6)$$

$$N_p B_o = N(B_o - (B_{oi})) + V_P (C_w S_{wi} + C_f) \Delta P + W_e \quad (3.1)$$

3.2.3 Gas cap expansion drive

The presence of a gas cap at initial reservoir conditions serves to retard the decline in reservoir pressure as oil is produced. The pressure at the original gas-oil contact is by definition the bubble point pressure since the oil must be saturated. The material balance equation must be formulated by taking , to consideration the expansion of the initial gas cap as well as liberation of solution gas from the oil as pressure declines. The efficient recovery of oil will

depend on keeping as much gas as possible in the reservoir to act as an expansion energy – completion intervals and location of oil wells are therefore particularly important. The volume of gas at initial reservoir conditions is related to the volume of oil initially in place at reservoir conditions by the ratio term m : then, in Havlena and Odeh formulation:

$$\frac{G(B_{gi})}{N(B_{oi})} = m \quad (3.3)$$

$$F = N[E_o + mE_g + (1 + m)E_{f,w}] + W_e \quad (3.4)$$

In this case W_e can include gas injection $G_{inj} B_g$. It is also expected that the term $E_{f,w}$ can usually be ignored since, in comparison with gas expansion it is small. This may not hold true in chalk reservoirs or other highly compressible unconsolidated sand reservoirs.

In the absence of influx and injection terms the material balance equation can be solved to provide estimates for m and N from production and PVT data by plotting $(F/(E_o + (1+m)E_{f,w}))$ against $(E_g/(E_o + (1+m)E_{f,w}))$ as shown in

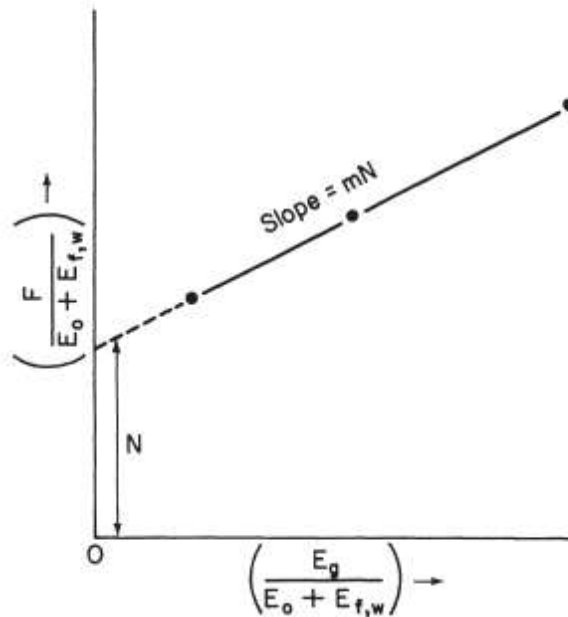


Fig. (3.4): Estimation of m and N from production and PVT data.(33)

The recovery factor N_p/N evaluated at different pressures during the life of a gas cap drive or solution gas drive recovery process is clearly related to the cumulative produced gas-oil ratio R_p . Since:

3.3 MATERIAL BALANCE FOR RESERVOIRS WITH WATER ENCROACHMENT OR WATER INJECTION

If a reservoir is underlain by, or is continuous with, a large body of water saturated porous rock (an aquifer), then reduction in pressure in the oil zone will cause a reduction in pressure in the aquifer. The total compressibility of an aquifer ($c_w S_w + c_r$) may be relatively large (about 10^{-6} to 10^{-5} pSi-l). The response time of an aquifer to a change in pressure at the original oil-water contact is of great practical importance. In small aquifers, steady state

$$\left. \frac{N_p}{N} \right| = \frac{E_r + W_e}{B_o + (R_p - R_s) B_g} \quad (3.5)$$

instantaneous Influx may be a good representation but large aquifers tend to behave in an unsteady state manner. [34]

When water is required for pressure support in an oil reservoir, the unsteady state response of an aquifer may negate its usefulness and external water injection is frequently used instead. Water injection allows a more immediate replacement of oil zone energy. The determination of aquifer characteristics is important if water injection is not planned. Two main aquifer geometries, radial and linear, may be considered in analytical analyses, although reservoir simulation can cope with irregular shapes. The properties of an aquifer are rarely known with any confidence since there is usually little well control. The basis for unsteady state aquifer analysis is found in the methods of van Everdingen and Hurst [35], Carter and Tracy and Fetkovitch [36]. They are used to provide estimates of cumulative water encroachment W_e in the total

influx term We' , and can be applied in material balance formulations, such as that due to Havlena and Odeh [37] and discussed in the previous sections. where W_{inj} is the cumulative water injection and G_{inj} is the cumulative gas injection both volumes being represented at standard conditions. The unsteady state aquifer representation of Hurst and van Everdingen requires the discretization of a continuous pressure decline into periods of Instantaneous pressure drop. If water injection is employed in a reservoir then natural water influx may still occur if the pressure at the original water contact decreases from initial pressure. The combination drive material balance equation which represents a step change from equilibrium at pressure P_i to equilibrium at pressure P can be formulated to show all expansion, production and injection terms as shown below. In this formulation the subscripts c and s refer in gas terms to conditions in the gas cap and in solution gas. W_{inj} and G_{inj} are cumulative injection volumes at stock tank conditions.

Present oil volume	Original oil volume	Freed solution gas	Gas cap expansion	Net water influx	Rock and connate water expansion	Injected volumes

$$\begin{aligned}
 (N - N_p)B_o = & N(B_{oi}) - \\
 & (B_g)_s \left[N(R_s)_i - (N - N_p R_s - (G_p)_s) \right] - \\
 & \left[(G - (G_p)_c)(B_g)_c - G(B_g)_i \right] - \\
 & \left[W_e - W_p B_w \right] - \\
 & N(B_{oi}) (1+m) \Delta P \left[\frac{c_f + S_{wi} c_w}{1 - S_{wi}} \right] - \\
 & \left[W_{inj} B_w + G_{inj} B_g \right]
 \end{aligned}$$

$$N = \frac{N_p(B_o - R_s(B_g)_s) + (G_p)_s(B_g)_s - \left[(G - (G_p)_c)(B_g)_c - G(B_g)_i \right] - \left[W_e - W_p B_w \right] - W_{inj} B_w - G_{inj} B_g}{(B_o - (B_{oi})) + ((R_{si}) - R_s)(B_g)_s + (B_{oi}) \Delta P \left[\frac{c_f + S_{wi} c_w}{1 - S_{wi}} \right] (1+m)}$$

3.4 ACCURACY OF THE GROSS MATERIAL BALANCE EQUATION

There are several sources of error in material balance calculations. Cumulative oil production is generally measured accurately for royalty and transfer payments. A single reservoir field then presents no difficulty and N_p will be the factor most precisely known. With Multi reservoir fields the individual reservoirs are not always (rarely!) metered separately, and the allocation of cumulatives to reservoirs depends on intermittent well testing. Nevertheless, this is not a major source of error. For the simplest calculations, the whole reservoir is assumed to be at some average datum pressure, corresponding to some cumulative production. All pressure dependent values refer to this pressure. The average pressure must be calculated from a series of essentially transient well tests, taken at varying times and positions, but practically never corresponding to a situation where the whole reservoir is shut in at one time. Regardless of the accuracy of the pressure data itself, the interpretation of average pressure from this data is possibly in error.[38]

3.5 Reservoir Performance Prediction:

All the techniques used to predict the future performance of a reservoir are based on combination of appropriate MBE with the instantaneous GOR using the proper saturation equation. The calculations are repeated at a series of assumed reservoir pressure drops. These calculations are usually based on stock-tank barrel of oil-in-place at the bubble-point pressure. Above the bubble point pressure, the cumulative oil produced is calculated directly from the material balance equations as presented in Craft & Hawkins (1991), Dake (1978), Tarek (2010), Cole (1969), Cosse (1993), Economides et al. (1994) & Hawkins (1955). The MBE for undersaturated reservoir are expressed below.[38]

1. For Undersaturated Reservoir ($P > P_b$) with No Water Influx

That is above the bubble point; the assumptions made are:

$$m = 0, W_c = 0, R_{si} = R_p, G_p = NR_p, W_{inj} = G_{inj} = 0, K_{rg} = 0, W_p = W_c \quad (3.6)$$

From Hawkin's equation, the isothermal compressibility of oil C_o , can be expressed as:

$$N = \frac{N_p B_o}{(B_o - B_{oi}) + B_{oi} \left(\frac{S_{wi} C_w + C_f}{1 - S_{wi}} \right) \Delta P}$$

$$C_o = \frac{1}{B_o} \left(\frac{\partial B_o}{\partial P} \right) = - \frac{1}{B_{oi}} \left(\frac{B_o - B_{io}}{P_i - P} \right) \quad (3.7)$$

$$B_o - B_{oi} = -C_o B_{oi} (P - P_i) = C_o B_{oi} (P_i - P)$$

Put these two equations into the N equation gives:

Expressing the isothermal compressibility in terms of effective compressibility,

$$N = \frac{N_p B_o}{C_o B_{oi} (P_i - P) + B_{oi} \left(\frac{S_{wi} C_w + C_f}{1 - S_{wi}} \right) \Delta P}$$

$$N = \frac{N_p B_o}{\Delta P B_{oi} \left(C_o + \frac{S_{wi} C_w + C_f}{1 - S_{wi}} \right)}$$

$$N = \frac{N_p B_o}{\Delta P B_{oi} \left(\frac{C_o (1 - S_{wi}) S_{wi} C_w + C_f}{1 - S_{wi}} \right)} \quad (3.8)$$

$$N = \frac{N_p B_o}{\Delta P B_{oi} \left(\frac{C_o S_o + S_{wi} C_w + C_f}{1 - S_{wi}} \right)}$$

NCoe. thus;

$$C_{oe} = \frac{C_p S_o + S_{wi} C_w + C_f}{1 - S_{wi}} \quad (3.9)$$

$$N = \frac{N_p B_o}{B_{oi} \Delta P C_{oe}} = \frac{N_p B_o}{B_{oi} C_{oe} (P_i - P)}$$

The cumulative oil produced in the undersaturated region can be calculated

$$N_p = \frac{N B_{oi} C_{oe} (P_i - P)}{B_o} \quad (3.10)$$

Where:

$$G_p = N_p R_{si}$$

2.Undersaturated Reservoir with Water Drive:

Assumptions: $W_{inj} = G_{inj} = 0$, $m = 0$

$$N = \frac{N_p B_o + W_p B_w - W_e B_w}{(B_o - B_{oi}) + B_{oi} \left(\frac{S_{wi} C_w + C_f}{1 - S_{wi}} \right) \Delta P} \quad (3.11)$$

In terms of effective oil compressibility

$$N = \frac{N_p B_o + W_p B_w - W_e B_w}{B_{oi} C_{oe} (P_i - P)} \quad (3.12)$$

$$N_p = \frac{N B_{oi} C_{oe} (P_i - P) + (W_e B_w - W_p B_w)}{B_o}$$

Where

$$G_p = N_p R_{si}$$

In applying the above methods of prediction for saturated reservoirs, we require some additional information to match the previous field production data in order to predict the future. Such relations are the instantaneous gas-oil ratio (GOR), equation relating the cumulative GOR to the instantaneous GOR and the equation that relates saturation to cumulative oil produced. On the contrary, despite the fact that the material balance equation is a tool used by the reservoir engineers, there are some aspects which were not put into consideration when performing prediction performance. These are:

- The contribution of the individual well's production rate
- The actual number of wells producing from the reservoir
- The positions of these wells in the reservoir are not considered since it is assume to be a tank model
- The time it will take to deplete the reservoir to an abandonment pressure
- Does not see faults in the reservoir if there is any and the variation in rock and fluid properties.

Chapter Four

Practical Work and Results

4.1 Methodology:

MBAL allows non dimensional reservoir analysis to be conducted throughout the life of the field, whether this is in early field life when limited data is available, or even in mature fields where more certainty exists. As such, this straightforward but powerful reservoir toolkit can be applied throughout the life of the reservoir, and is often used in conjunction with numerical simulators as a quality check of history matching, and/or as a proxy model for fast calculations.

The tool used the obtained data to get the OOIP and make perfect history matching for the pressure and production history that help us to predict the performance of the well and reservoir. Also show the drive mechanisms of the reservoir.[39]

The flow chart below shown the methodology of the research.

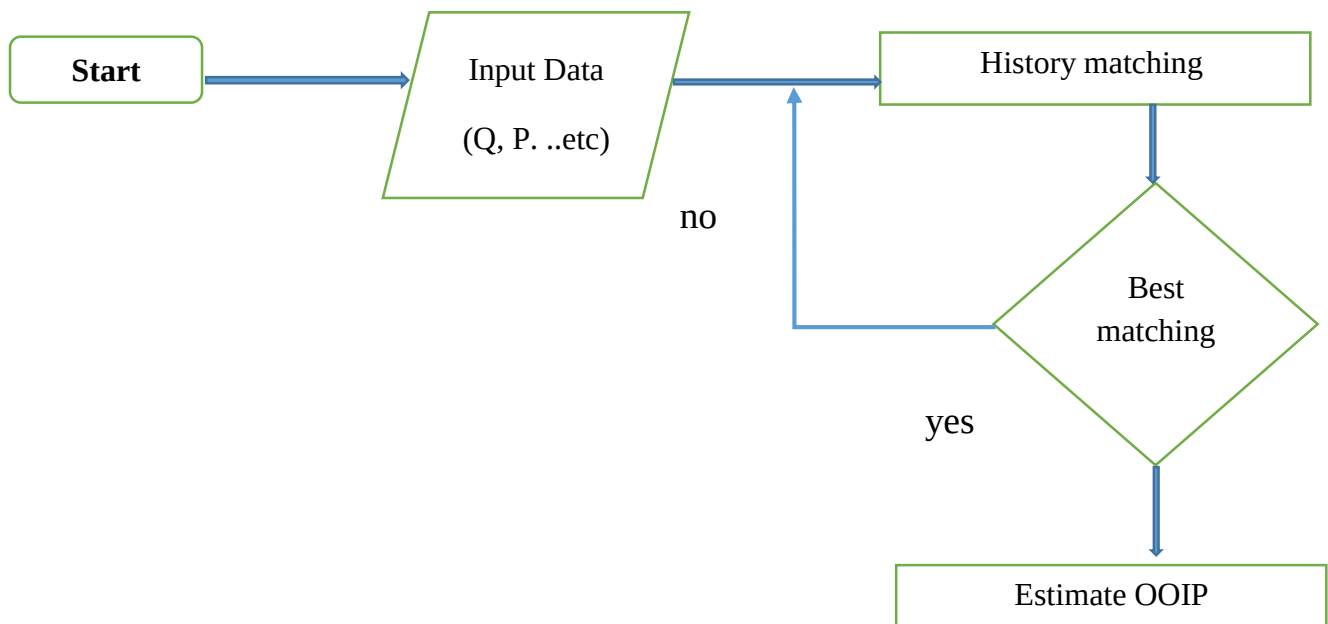


Fig.4.1: Methodology of the research.

An abstract idea about material balance was exhibited by Schilthuis in 1941 which was based on the mass conservation law. There was certain assumption made in this technique where reservoir considered as a homogenous tank model [12]. The material balance used for history match and past performance for estimation volume of reservoir and prediction of future performance. MBAL software based on this concept while using minimum data the reservoir engineer can be used this tool for reservoir analysis throughout the life of the field. Basic equation used in MBAL software i.e.

$$F - W_e = (E_o + mE_g + Ef_w) \quad (4.1)$$

4.2. Workflow Procedure

In analytical reservoir engineering tool kit MBAL software is progressive option for running a simulation based on historical data which should be matched with analytical model. MBAL provides substantial matching facilities and aquifer modelling which advances research about pressure support response and forecasting. There were certain steps followed during this research study to forecast the performance for selected reservoir [40].

- 1- PVT, cumulative oil Production and pressure depletion data were entered while considering a tank model.
- 2- The matching amenities available in MBAL were used to adjust the empirical fluid property correlations to fit PVT laboratory data. To foremost fit for the measured data, correlations were modified using non-linear regression techniques then selected for use in the model.

- 3- Glaso-correlation was selected for saturation pressure, Gas-oil ratio and Formation volume factor; and beggs-correlation selected for viscosity.
- 4- Tank data included for further reservoir model development like Initial pressure, porosity, Reservoir Temperature, Initial hydrocarbon in place, connate water saturation and production start date data. Initial hydrocarbon in place calculated based on Geological data. History matching requires past production data along with pressure declination. Reference data is obtained from L.P. Dake.

4.3. Input Parameters:

The input data into MBAL model consist PVT properties, Oil and gas Production data, aquifer parameter, relative permeability data, reservoir thickness. Porosity and Permeability data were obtained from well logs. Correlation were used to evaluate relative permeability. A summary of input PVT data, Reservoir Tank data and relative permeability data shown in Table 4.1, Table 4.2 and Table 4.3 respectively. Additional Water influx data which is shown in Table 4.4 required during the Campbell plot shows variation which shows that an unaccounted energy source was contributing to the historical production.

4.4. Reservoir Model Description:

Initially the material balance analysis is conducted assuming the reservoir as a volumetric depletion drive type reservoir using MBAL, Reservoir Engineering Toolkit of Petroleum Experts. The reservoir model was initiated with pressure, production and PVT data listed in **Table 3.1**. Data input in the tank with initial

pressure 4000 psi and other reservoir data as shown in **figure 3.1**. Then, history matching was developed to show the performance of the reservoir and estimation OOIP. Also, to identify the contribution of all drive mechanism that found in the reservoir and the average oil rate for any period. After that, generating production prediction by input constraint data.

Table3.1. Reservoir rock, pressure, production and PVT data.

Date	Pressure (psia)	Np(MMSTB)	Wp(MSTB)	Bo
01/01/1988	4270	0.012009	0	1.37607
01/01/1994	4103	0.023078	0	1.36088
01/01/1996	3830.2	0.029503	0.01139	1.34344
01/01/1998	3799.7	0.039701	0.02067	1.35671
01/01/2000	3694.8	0.045318	0.03144	1.36823
01/01/2001	3653.5	1.578 173	82.73963	1.37003
01/01/2002	3544.1	1.78439	182.5022	1.369 18
01/01/2003	3510.22	2.24664	359.8776	1.3723
01/01/2004	3470.55	3.75291	400.4966	1.37331
01/01/2005	3450.4	3.90623	400.4966	1.3671
01/01/2006	3549.4	3.90623	400.4966	1.3671
01/01/2007	3504.35	4.90127	400.4966	1.3673
01/01/2008	3466.01	5.19783	400.4966	1.336692
01/01/2009	3410.47	5.20256	400.4966	1.37037
01/01/2010	3363.24	5.69292	400.4966	1.37127
1/1/2011	3346.77	5.89202	400.4966	1.37087

Table 3.2 : PVT Data and reservoir properties.

No.	parameter	value
1	OOIP	21MMSTB
2	ϕ	0.32
3	INTIAL GAS CAP	0
4	swi	0.15
5	Pi	4270 PSI
6	Temperature	200 °F
7	GOR	1589 SCF/STB
8	API	39
9	Gas gravity	0.875
10	Water salinity	100000 ppm

Table 3.3: Relative permeability data

KRO	0.15	0.8	2.25
KRW	0.15	0.03	0.01
Krg	0.05	0.00033	0.01

4.5 Program steps:

Firstly, chose the type of tank as single tank and the reservoir fluid as oil.Also, the model of PVT as illustrated in figure 4.2:

System Options

☒ Done
 ☒ Cancel
 ☒ Help

Fig.(4.4): Selection of type of tank and reservoir.

Tool Options

Reservoir Fluid: Oil
 Tank Model: Single Tank
 PVT Model: Simple PVT
 Production History: By Tank
 Compositional Model: None

EOS Model Setup...

User Information

Company:
 Field:
 Location:
 Platform:
 Analyst:

Reference Time: 01/01/1900 date m/d/y

User Comments: Date Stamp: (Ctrl+Enter for new line)

The next step input the fluid properties as shown in figure (4.5):

Oil - Black Oil: Data Input

Done Cancel Help Match Table Import Export Calc Match Param.

Input Parameters

Formation GOR 1589 scf/STB

Oil gravity 39 API

Gas gravity 0.875 sp. gravity

Water salinity 100000 ppm

Mole percent H2S 0 percent

Mole percent CO2 0 percent

Mole percent N2 0 percent

Separator

Single-Stage

Correlations

Pb,Rs,Bo

Standing

Oil Viscosity

Beal et al

☐ Use Tables

☐ Use Matching

☐ Controlled Miscibility

Fig. (4.3): Fluid and reservoir properties.

Tank Input Data - Tank Parameters

Done Cancel Help Import

Tank Parameters Water Influx Rock Compress. Rock Compaction Pore Volume vs Depth Relative Permeability Production History

Tank Type Oil

Name Test Pric

Temperature 200 deg F

Initial Pressure 4267 psig

Porosity 0.32 fraction

Connate Water Saturation 0.15 fraction

Water Compressibility Use Corr 1/psi

Initial Gas Cap 0

Original Oil In Place 21 MMSTB

Start of Production 01/01/2001 date m/d/y

☐ Monitor Contacts

☐ Gas Coning

☐ Water Coning

☐ Use Fractional Flow Table (instead of rel perms)

Calculate Pb...

After that input the reservoir parameters as shown in figure (4.6):

Figure (4.4): Input reservoir parameters

To make history matching and prediction for future production and the reservoir pressure decline must input production history of the reservoir for a period time as shown in figure (4.7):

Tank Input Data - Production History

Done

Cancel

Help

Import

Plot

Report

Copy

Layout

Tank Parameters

Water Influx

Rock Compress.

Rock Compaction

Pore Volume vs Depth

Relative Permeability

Production History

	Time	Reservoir Pressure	Cum Oil Produced	Cum Gas Produced	Cum Wat. Produced	Cum Gas Injected	Cum Wat. Injected	Regression Weighting	Comment
	date m/d/y	psia	MMSTB	MMscf	MMSTB	MMscf	MMSTB		
1	01/01/1988	4270	0.012009	0	0			Medium	Edit..
2	01/01/1994	4103	0.023078	2894	0			Medium	Edit..
3	01/01/1996	3830.2	0.029503	4022.07	0.01139			Medium	Edit..
4	01/01/1998	3799.7	0.039701	4142.07	0.02067			Medium	Edit..
5	01/01/2000	3694.8	0.045318	4266.07	0.03144			Medium	Edit..
6	01/01/2001	3653.5	1.578	4390.07	82.7396			Medium	Edit..
7	01/01/2002	3544.1	1.78439	4510.07	182.502			Medium	Edit..
8	01/01/2003	3510.22	2.24664	4634.07	359.878			Medium	Edit..
9	01/01/2004	3470.55	3.75291	4754.07	400.497			Medium	Edit..
10	01/01/2005	3450.4	3.90623	4878.07	400.497			Medium	Edit..
11	01/01/2006	3549.4	3.90623	5002.07	400.497			Medium	Edit..
12	01/01/2007	3504.35	4.90127	5358.07	400.497			Medium	Edit..
13	01/01/2008	3466.01	5.19783	5482.07	400.497			Medium	Edit..
14	01/01/2009	3410.47	5.20256	5602.07	400.497			Medium	Edit..
15	01/01/2010	3363.24	5.69292	5726.07	400.497			Medium	Edit..
16	01/01/2011	3346.77	5.89202	5850.07	400.497			Medium	Edit..

<< Prior

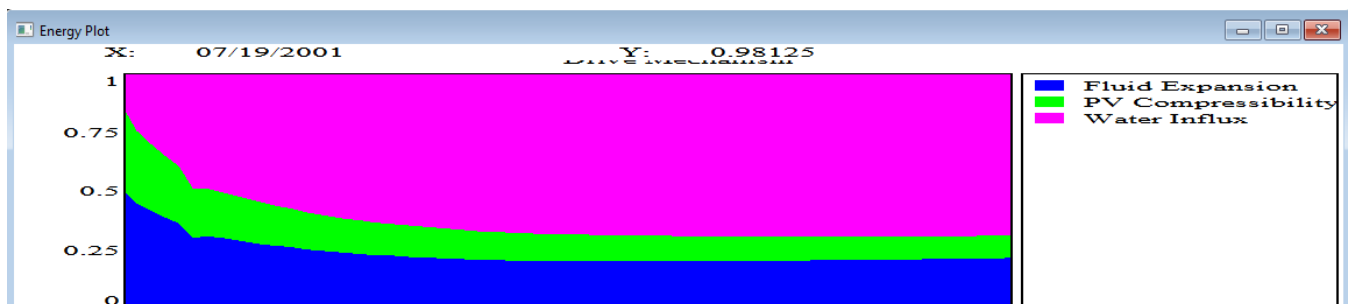
Next >>

☐ Work with GOR

figure (4.5): Production History data

4.6 Result:

From the energy plot (Figure 3), there is a pictorial representation of the



different drive mechanisms and their contribution to the energy of the reservoir.

Fig. (4.6): Drive mechanism contribution.

Chapter Five

Conclusions and Recommendations

5.1 Conclusion

Results obtained from different graphs the following conclusions are drawn from this research work. In reservoir engineering material balance equation is an important investigative tool when time is limited. This is very sophisticated analytical tool for evaluating reserve volume through historical production. In this study it has been proved that good data acquisition is required to carried out reserve volume evaluation with MBAL. Reservoir analysis tool MBAL is used to initialize, calibrate and benchmark the history matching. The main source of energy in reservoir was from Water influx and rock and fluid expansion drive mechanism. Water system energy provide about 50% of the reservoir energy which is required for oil recovery. The Hurst van Everdingen water influx model best describe the reservoir. The cumulative oil produced for the historical period was 5.7 MMSTB from 33.4 MMSTB , with recovery factors of 17% and 11.58% respectively. The total amount of cumulative water production for the historical period was 1.88 MMSTB and 3.86 MMSTB for forecasts period. Material balance was utilized in reservoirs where enough adequate data were available for History matching and Performance prediction. Finally, central objective of this paper with the help of reservoir simulation fulfilled to produce future prediction that will lead to optimize reservoir performance which meant reservoir developed in the manner that brings utmost benefit to the commercial business.

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الملخص:

يُعد التنبؤ بأداء المكامن النفطية جانباً أساسياً في تخطيط تطوير حقول النفط والغاز وتقدير الاحتياطيات، حيث يساهم في فهم سلوك المكامن مستقبلاً. يعتمد نجاح إنتاج المكامن على التمثيل الدقيق لخواص الصخور المكمنية، وخواص الموائع، وتفاعلات الصخر-المائع، بالإضافة إلى سلوك الجريان داخل المكامن. لذلك، يجب على مهندسي المكامن امتلاك فهم عميق لخصائص المكامن، وتقنيات تحسين الإنتاج، والأهم من ذلك القدرة على تطوير نماذج تحليلية تصف بشكل دقيق العمليات الفيزيائية التي تحدث داخل المكامن.

لقد تم تناول التنبؤ بأداء المكامن بالاعتماد على معادلة توازن المادة من قبل عدد من الباحثين مثل **Morris Muskat** و **Craft and Hawkins** و **Tarner** و **Havlena and Odeh** و **Henry Tracy** و **Schilthuis**، حيث تُعد هذه الطرق الأساس النظري للتنبؤ بأداء المكامن تحت ظروف تشغيل مختلفة.

في هذه الدراسة، تم تقدير احتياطي المكامن باستخدام كل من المحاكاة الديناميكية وطريقة توازن المادة التنبؤية بعد تحقيق تطابق تاريخي مُرضٍ. وقد تم إجراء التحليل باستخدام برنامج **MBAL** لتقييم كفاءته في المطابقة التاريخية والتنبؤ بأداء المكامن. يهدف هذا العمل إلى بناء نموذج مكمني موثوق ومقارنة تقنيات النمذجة المختلفة والتحقق منها من خلال دراسات حالة.

تم جمع بيانات الحقل، بما في ذلك تحاليل **PVT** وبيانات الإنتاج وبيانات الآبار، وتحليلها لضمان جودة البيانات وتوافقها مع السلوك الفيزيائي للمكامن باستخدام العلاقات المناسبة. كما تم إجراء المطابقة التاريخية لموائمة نتائج النموذج مع الظروف الفعلية للمكامن، خاصة في تقدير النفط الأصلي في المكامن وحجم المكامن المائي.

أظهرت النتائج المستخلصة من مختلف الرسوم البيانية والعلاقات بين المعلمات توافقاً جيداً بين بيانات المطابقة التاريخية ونتائج المحاكاة. كما أظهرت تنبؤات الأداء المستقبلي توافقاً بين طريقتي توازن المادة والمحاكاة، مما يؤكد موثوقية أسلوب النمذجة المتكاملة في تقييم أداء المكامن الكربونانية والتنبؤ بسلوكها المستقبلي.



جمهورية العراق
وزارة التعليم العالي والبحث العلمي
جامعة الكتاب
كلية الهندسة
قسم هندسة النفط

في أحد الحقول النفطية **MBAL** تقدير النفط الأصلي في الممكن باستخدام برنامج
في العراق

مشروع مُقدّم إلى
قسم الهندسة النفط، كلية الهندسة / جامعة الكتاب
كجزء من متطلبات نيل درجة بكالوريوس
في علوم هندسة النفط
من قبل
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اسيل جابر سليم

بإشراف
دكتور عدنان عجم
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College of Engineering
Petroleum Engineering Department

***Optimizing Production Efficiency in Mature Oil Fields: A Study
on Foam Lift Techniques***

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A project submitted in partial fulfilment of the requirements for the award of
Bachelor's Degree in Petroleum Engineering

Petroleum Engineering Department
Al-Kitab University
Altun Kupri, Kirkuk – Iraq
May 2026

Declaration

We hereby declare that the graduation project titled "Optimization of Production Efficiency in Mature Oil Fields: A Study on Foam Lift Techniques" is our own original work and has been carried out under the supervision of [Assist. Prof. Dr. Pshtiwan Jaf].

We confirm that this work has not been submitted previously, in whole or in part, for the award of any degree or diploma in any institution. All sources of information and data used in the project have been properly acknowledged.

We fully understand the consequences of plagiarism and affirm that this work complies with the academic integrity policies of our institution.

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Abstract

This project aims to enhance production efficiency in aging oil fields by employing foam lift methods, with a focus on improving performance. The study utilized PROSPER software to evaluate the Foam Lift techniques associated with Continuous Gas-Lift on two oil wells in Iraq's Kurdistan region under different operational conditions, such as variations in water cut, gas-liquid ratio (GLR), and API gravity. The goal was to determine the impact of foam injection on fluid deliverability by decreasing hydrostatic pressure and stabilizing multiphase flow.

The simulation results indicated that foam-assisted lift boosts production rates and increases API gravity by improving fluid mobility and reducing heavier components in the output stream. In situations where natural flow was hindered by increased water cut, foam injection successfully restored flow by decreasing the fluid column density. This technique effectively prolonged the productive lifespan of both wells examined. While the primary focus was on technical results, the study also briefly explored the use of biodegradable foaming agents as an environmentally friendly option to promote sustainable field operations.

Nomenclatures

Symbol / Abbreviation	Definition	Unit
API	American Petroleum Institute gravity	degrees (°API)
GLR	Gas-Liquid Ratio	SCF/STB
GOR	Gas-Oil Ratio	SCF/STB
WC	Water Cut	%
Q_o	Oil production rate	STB/day
P_{wf}	Flowing bottom-hole pressure	psig
BHP	Bottom-hole pressure	psig
IPR	Inflow Performance Relationship	-
VLP	Vertical Lift Performance	-
PVT	Pressure-Volume-Temperature analysis	-
ESP	Electrical Submersible Pump	-
FAGL	Foam Assisted Gas Lift	-
GAFL	Gas-Assisted Foam Lift	-
MES	Methyl Ester Sulfonates	-
APG	Alkyl Polyglucoside	-
STB	Stock Tank Barrel	Barrel
MMscf/day	Million standard cubic feet per day	MMscf/day
cp	Centipoise (viscosity)	cP

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Chapter 1: Introduction

1.1 Background

Approximately two-thirds of the world's daily oil production comes from mature oil fields, as reported by Information Handling Services Cambridge Energy Research Associates ([Munisteri and Kotenev, 2013](#)). These fields are typically characterized as having produced over 50% of their established proved plus probable resource estimates or having been in operation for more than 25 years. Different companies have their own criteria; for example, Total considers a field mature when cumulative production reaches 50% of initial reserves for subsurface assessment or after 10 years of production for surface evaluation. Halliburton, however, defines a mature field as one where production has reached its peak and begun to decline ([Munisteri and Kotenev, 2013](#)).

Despite varying definitions, mature fields are globally recognized as valuable assets due to the relatively low risk associated with efforts to increase reserve levels (PetroWiki). The process of revitalizing mature fields involves implementing strategies to extract additional value from the reservoir beyond initial expectations by extending the natural decline curve. This approach enhances ultimate economic hydrocarbon production. The high oil price of 147 USD per barrel on the mid of 2008, made many mature fields attractive candidates for redevelopment (PetroWiki).

The main challenge in developing mature fields lies in identifying the remaining oil, which persists due to inefficient displacement (residual oil in swept zones) or poor sweep efficiency (bypassed oil) ([Banerjee, 2013](#)). Once the remaining oil is evaluated, recovery methods are categorized into various advanced techniques, including tertiary recovery, infill drilling, horizontal wells, optimal waterflooding design, and other reservoir management practices ([Babadagli, 2007](#)). These approaches have been successfully implemented in both major fields and smaller fields operated by independent companies.

Specific techniques for production optimization, as illustrated in Figure 1.1 [5], include the following:

- Near-wellbore profile management
- Gas-water coning and fingering control
- Near-wellbore conformance management
- Removal of near-wellbore damage
- Matrix stimulation or acidizing
- Hydraulic fracturing
- Maximizing the productivity index
- Multilateral completions for maximum-reservoir-contact wells
- Prevention of organic and inorganic solid deposition
- Well integrity management
- Casing and cement failure remediation
- Optimization of artificial lift performance
- Sand control management
- Debottlenecking production systems
- Design and optimization of surface facilities and fluid handling capacity

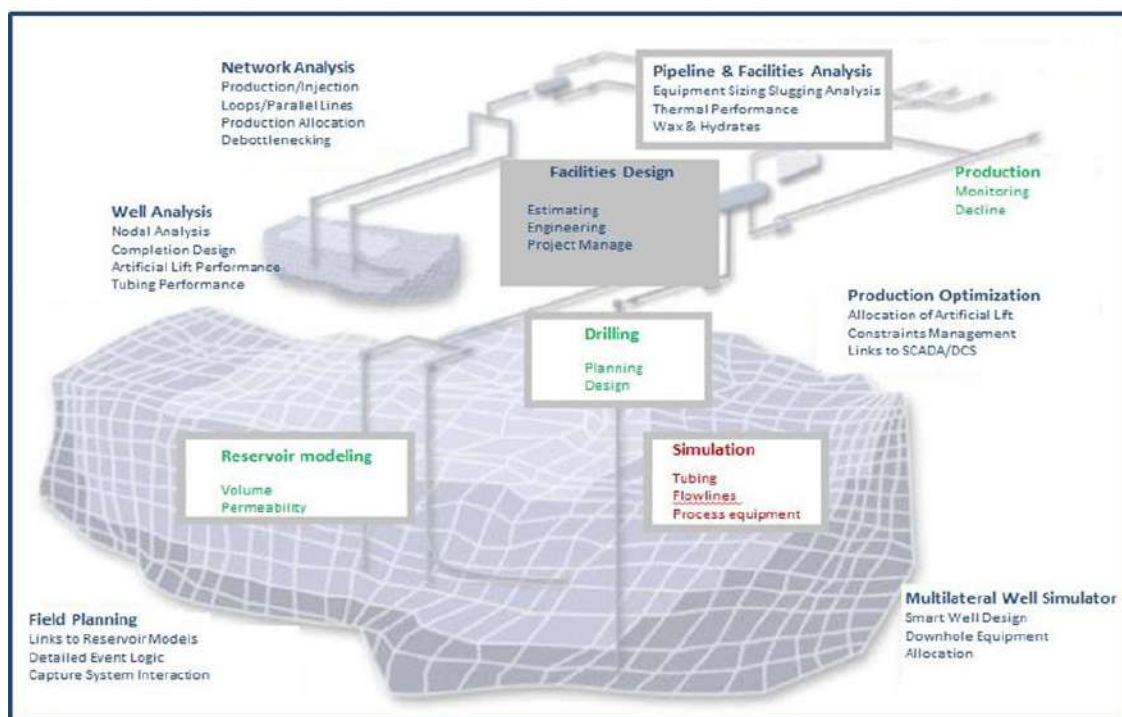


Figure 1.1 Various approaches to petroleum system production optimization

1.2 Optimization Techniques

The optimization of oil and gas production encompasses various sophisticated strategies aimed at boosting efficiency and productivity. Mathematical approaches such as Linear Programming (LP) and Nonlinear Programming (NLP) are employed to optimize resource distribution and address intricate constraints, while Mixed Integer Linear Programming (MILP) incorporates integer variables for discrete decision-making. Nature-inspired heuristic techniques, including Genetic Algorithms (GA), Simulated Annealing (SA), and Particle Swarm Optimization (PSO), are utilized to identify optimal solutions in extensive problem domains, particularly when conventional methods prove inadequate. Another crucial tool is nodal analysis, which is used to equilibrate fluid flow and pressure within production systems. The integration of these methodologies facilitates improved reservoir management, well optimization, and equipment scheduling, resulting in enhanced production rates, decreased expenses, and streamlined oil and gas operations ([Kumar et al., 2021](#)).

Nodal analysis

Nodal analysis is crucial in numerous applications that significantly benefit the oil and gas extraction industry. It evaluates each component in the production system to optimize flow and identifies and addresses bottlenecks, improves overall system efficiency. Production engineers rely heavily on this widely recognized and dependable method to predict various reservoir parameters, which forms the basis for daily oilfield operations planning. The essence of nodal analysis involves adjusting different parameters to identify key points that align with the primary objective: maximizing production in a cost-efficient manner without causing harm to the reservoir. This approach enables engineers to pinpoint the most critical areas for optimization, ensuring both productivity and reservoir integrity are maintained ([Kumar et al., 2021](#)).

Nodal Analysis is used to predict the well rate and performance by combining the reservoir inflow with the wellbore lift capacity by intersecting the Inflow Performance Relationship IPR and Vertical Lift Performance VLP curves on a pressure vs rate plot. For the given reservoir Well Nodal Analysis calculates how much oil, water and gas can be produced by the given well. It allows to:

1. Calculate the well production potential and identify the performance gaps to maximize oil and gas production.

2. Evaluate the various well nodes impact on production. Nodes: reservoir, perforation, tubing string, restrictions, downhole safety valves, the surface chokes, the surface flow lines and separator.

Typical Applications include:

- Estimation of well production potential and absolute open flow (AOF)
- Tubing sizing
- Selection of the operating wellhead pressures
- Artificial lift design. Gas lift. Electrical Submersible Pump ESP sizing.
- Sensitivity studies

Well Nodal Analysis is done on a pressure vs rate plot. IPR and VLP curves intersect at well operating point. Well, IPR curve: Darcy's law, Vogel's IPR, Composite IPR. Well, VLP curve: Hagedorn and Brown multiphase flow correlation ([Zhou et al., 2016](#))

Foam lift can be integrated with other artificial lift techniques. For instance, a gas lift well can employ foam to optimize production. The appropriate treatment method must be chosen to transform the gas lift well into a foam-assisted gas lift system. As previously mentioned, foaming and defoaming agents are essential for foam lift operations and must be connected to the well at the correct location on the surface ([Martins et al., 2019](#)).

The two common foam application methods are tubing-inserted capillary string and injection into the casing via a gas lift valve. The capillary string method uses standard equipment and chemicals, providing faster well response. However, it comes with high installation and maintenance costs, long lead times, and the loss of well access during operation.

On the other hand, the gas lift injection method maintains well access and offers lower installation costs with faster deployment. While it is more cost-effective in terms of installation and maintenance, it has a slower well response and faces challenges such as limited long-term

experience, a new chemical injection approach, and the uncertain risk of corrosiveness in the annulus (Martins et al., 2019), as it shows in (Figure 1.2).

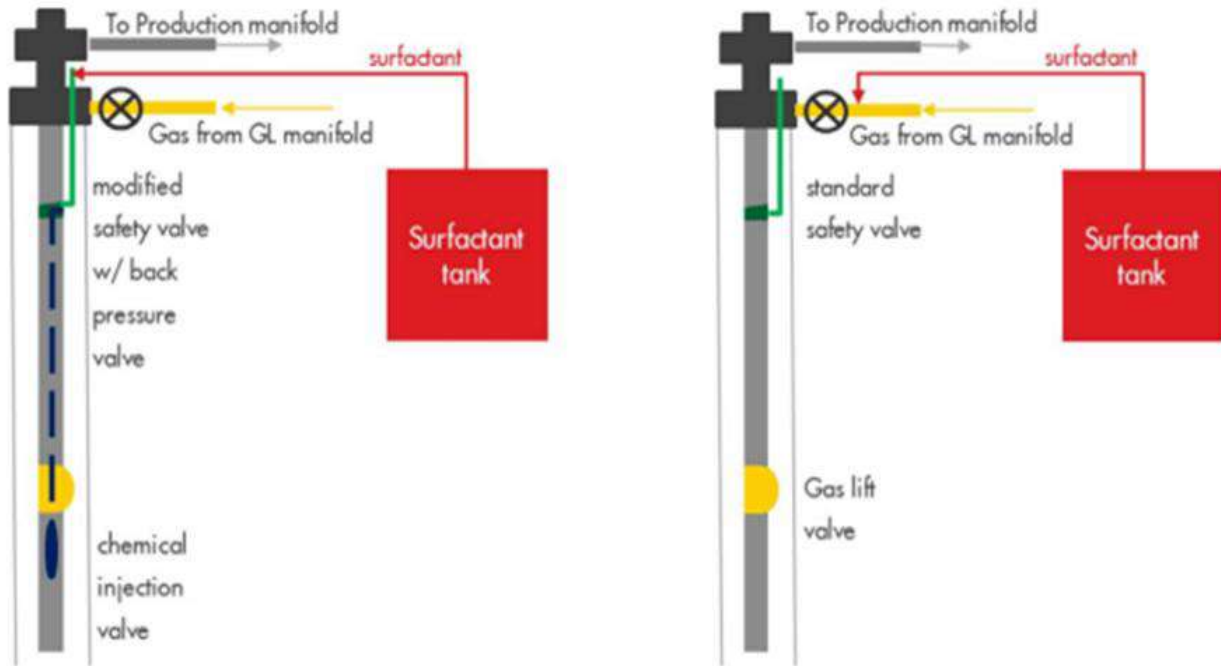


Figure 1.2 Schematic of FAGL installation with a capillary string (a) and with injection in the gas lift line (b). The surface skid delivering the surfactant is the same in both configurations.

1.3 Research Objectives

This project aims to optimize production efficiency in mature oil fields by leveraging foam lift technology, contributing for any future plans for Kurdistan. Foam lift, an artificial lift method, entails injecting foaming agents into wells to decrease hydrostatic pressure and enhance fluid extraction to the surface. By emphasizing foam lift applications, the project seeks to mitigate common challenges in aging fields, including declining production rates, excessive water cuts, and well integrity problems. The initiative will examine foam lift's efficacy in boosting oil production, cutting operational costs, and extending the productive lifespan of mature wells.

The main objective of introducing a surfactant is to create foam from gas flow, as gas bubbles through the liquid. The resulting foam decreases the hydrostatic pressure of the fluid column, triggering an

increase in gas production. This enhanced gas production generates more foam, further reducing back pressure. The unloading process can be executed through either batch treatment or continuous injection (Solesa and Sevic, 2006). Surfactants, which act as foaming agents, possess both polar and non-polar components within a single molecule: a non-polar hydrophobic part and a hydrophilic portion. This unique structure allows surfactants to serve as a linking interface between two immiscible fluids (Barreto et al., 2017).

1.4 Scope of the Study:

This study examines the application of foam lift technology to boost production in aging oil fields, with a focus on technical and operational aspects. The research seeks to evaluate the viability and efficiency of foam lift in addressing the challenges encountered by mature fields, including declining output rates, higher water cuts, and well integrity concerns.

Technical Scope:

- **Technology Examination:** The research will assess foam lift's capacity to address common issues in mature fields, such as low production and excessive water output. It will also investigate the integration of foam lift with other artificial lift techniques, including gas lift and electrical submersible pumps (ESPs), to enhance well efficiency.
- **Optimization Techniques:** The primary method for optimizing foam lift performance will be nodal analysis. This approach identifies bottlenecks by evaluating various components such as the reservoir, tubing string, and surface flow lines, with the goal of maximizing oil and gas production (Al-Hussainy et al., 1966).
- **Effectiveness Assessment:** The study will implement a framework to evaluate foam lift's efficacy, utilizing key performance indicators (KPIs) such as production rates, environmental impact, and well integrity. These KPIs will be monitored to gauge the success of foam lift implementation (Ahmad et al., 2017).

Chapter 2: Literature Review

This chapter delves into the comprehensive analysis and optimization of production systems in petroleum engineering, with a focus on techniques aimed at enhancing oil recovery and efficiency. The discussion begins with an exploration of production system analysis, highlighting critical components such as the Inflow Performance Relationship (IPR), Vertical Lift Performance (VLP), and total system analysis, which form the foundation for understanding well behaviour. Building upon this, the chapter examines well optimization techniques, including artificial lift methods and their application in improving production efficiency. Special attention is given to foam lift methodology, covering its operational aspects, various foam lift techniques in mature oil wells, specific technical requirements, and recent research advancements. By synthesizing insights from these sections, the chapter aims to provide a detailed understanding of the key strategies and methodologies employed in modern production systems, ultimately aiding in the development of more efficient and sustainable oil recovery solutions.

2.1. Production System Analysis

Various studies have been conducted to explore different optimization techniques and models to enhance the efficiency and performance of oil and gas production systems. ([Camponogara and Nakashima, 2006](#)) explored gas-lift optimization for oil wells using a piecewise linear formulation. Their study contributed to the field by analyzing the properties of polyhedra related to feasible solutions and introducing valid inequalities to enhance the performance of optimization software. This research underscored the importance of gas-lift techniques—where compressed gas is injected into production tubing to sustain oil flow—as a key method for improving production efficiency. However, the study primarily focused on theoretical aspects, leaving room for practical application studies in complex field conditions. ([De Souza et al., 2010](#)) delved into modeling, simulation, and optimization of continuous gas lift systems for deepwater offshore petroleum production. This study aimed to enhance the efficiency and effectiveness of gas lift systems in challenging offshore environments. ([AlJuboori et al., 2020](#)) conducted a feasibility study on gas lift optimization using a Genetic Algorithm for a Middle Eastern oil field. The study focused on optimizing the allocation of gas-lift injection rates in a network system to improve production efficiency. The optimization model was designed to guide production engineers in optimizing gas injection rates for individual wells in a network system. ([Li et al., 2017](#)) discussed research advances and debates on tubular mechanics in oil

and gas wells, highlighting the importance of understanding the mechanical aspects of production systems for optimal performance. In a study by (Li et al., 2020), the focus was on reducing the carbon footprint of deep-sea oil and gas field exploitation through optimization for floating production storage and offloading. The study aimed to make offshore production more sustainable by optimizing production processes. Overall, these studies demonstrate the importance of production system analysis in optimizing oil and gas production. Various optimization techniques, models, and algorithms are being explored to enhance production efficiency, reduce environmental impact, and improve overall performance in the petroleum industry.

2.1.1 Inflow Performance Relationship (IPR)

Inflow Performance Relationship (IPR) is a tool used in the oil and gas industry for designing well completions, optimizing production, and forecasting future deliverability. Various studies have been conducted to develop models and correlations to accurately predict the IPR curve for different types of reservoirs. (Vogel, 1968) presented an early study on Inflow Performance Relationships for Solution-Gas Drive Wells, laying the foundation for further research in this area. (Elias et al., 2009) introduced a new model to predict the IPR curve for solution-gas drive oil reservoirs, emphasizing the importance of accurately describing oil mobility as a function of reservoir pressure. (Qasem et al., 2012) investigated the effects of reservoir heterogeneity on IPR curves for wells producing from multi-layer solution-gas drive reservoirs, using a stochastic simulation algorithm to generate permeability realizations. Another study by (Qasem et al., 2012) focused on modeling IPR for wells producing from two-layer solution-gas drive reservoirs without cross-flow, highlighting the importance of monitoring well performance and forecasting future deliverability. (Yaqiang et al., 2013) explored Horizontal Well Inflow Performance Relationships in Foamy Heavy Oil Reservoirs, while (Fattah et al., 2014) developed a new IPR model for solution-gas drive oil reservoirs. (Tan et al., 2014) established a mathematical model for gas-water two-phase flow to determine the IPR of water-producing gas wells using a multi objective optimization method. (Yuan et al., 2016) presented an integrated approach to evaluate fracturing stimulation efficiency and predict well production performance, focusing on transient flow production characteristics in shale reservoirs. (Zhang et al., 2020) proposed a new method for calculating IPR in sucker rod pump wells based on real-time monitoring dynamometer card data, addressing limitations in current calculation methods. In a more recent study, (Zhang et al., 2021) developed a novel mathematical model considering real gas PVT behavior to estimate the IPR

of gas well production accurately, improving calculation accuracy by eliminating errors caused by linearization methods.

The general IPR productivity equation for three-phase flow is applicable to both saturated and unsaturated reservoirs (Wang et al., 2021). For undersaturated oil reservoirs, the Vogel method is commonly used, with considerations for two different models (Fanchi, 2005). In the case of damaged reservoirs, an analytical model for predicting the productivity of radial-lateral wells has been developed, which can be applied to under-saturated oil reservoirs and dry gas reservoirs (Guo et al., 2020). Furthermore, an integrated approach has been utilized to confirm laboratory measurements with actual deposits found in production, emphasizing the importance of accurate modeling in reservoir analysis (Syed et al., 2019). Additionally, neural networks have been employed to predict well inflow performance based on different fluid properties and relative permeability curves, providing valuable insights into reservoir behavior (Alrumah, 2004). Overall, the application of various IPR models in different reservoir conditions, including saturated, undersaturated, and damaged reservoirs, highlights the importance of accurate modeling for understanding reservoir performance and optimizing production strategies. Reliable computer modeling is crucial for overcoming challenges in reservoir management and exploitation (Lie, 2016).

2.1.2 Vertical Lift Performance (VLP)

Vertical Lift Performance (VLP) refers to the analysis and modeling of the relationship between the pressure and flow rate of fluids as they move upward through a wellbore. It describes the pressure losses that occur due to friction, gravity, and fluid acceleration as the fluid travels from the reservoir to the surface. (Fevang et al., 2012) conducted a study on Vertical Lift Performance (VLP) models using data from the Statfjord field during the blowdown phase. The study analyzed the accuracy of various multiphase pressure drop correlations in predicting VLP based on production tests from six wells. The top three correlations recommended were Petroleum Experts, Petroleum Experts 2, and Petroleum Experts 3. However, the study found that accurate predictability varied with different flow conditions, such as Gas-Liquid Ratio (GLR) and wellhead pressure. Tuning the correlations improved predictability within limited GLR ranges, but larger ranges remained challenging. The study emphasized the importance of accurate VLP modeling for predicting production rates during the blowdown phase. (Al Shehri et al., 2020) utilized machine learning methods, including Artificial

Neural Networks (ANN), Functional Networks (FNN), and Long-Short Term Memory (LSTM) models, to estimate flowing bottom-hole pressure in unconventional gas condensate tight sand fractured wells in Saudi Arabia. This approach demonstrates the use of advanced computational techniques in predicting flow behavior in complex well systems. (Hamed et al., 2023) focused on predicting multiphase flow behavior in wells in the Faihaa oil field in Iraq using PIPESIM software. This study highlights the importance of selecting optimal correlations for vertical lift performance to accurately predict flow behavior in oil fields.

2.1.3. Total System Analysis

Crude oil engineering relies heavily on well performance modeling, which integrates various reservoir and production factors to maximize output. Two crucial elements in this analysis are the Inflow Performance Relationship (IPR) and Vertical Lift Performance (VLP) curves, which offer insights into reservoir capabilities and fluid delivery to the surface. These components form a comprehensive model of well performance (Eli et al., 2013, Ismail et al., 2018).

The IPR and VLP both correlate wellbores flowing pressure with surface production rate. The IPR depicts the reservoir's delivery to the bottom hole, while the VLP represents the well's surface delivery capacity. The point where these curves intersect, known as the operating point, determines well deliverability – the actual production for specific conditions (Pr, PI, WC, GOR, THP, tubing size) (Fetoui, 2017). As it shows in figure 2.1:

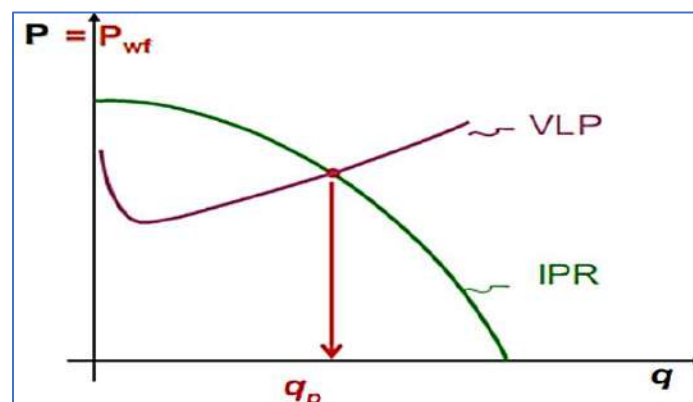


Figure 2.1 The intersection of the IPR with the VLP, called the operating point, yields the well deliverability, an expression of what a well will actually produce for a given operating condition (Pr, PI, WC, GOR, THP, Tubing size...).

Several factors can prevent IPR and VLP intersection: diminishing reservoir pressure, which reduces fluid flow force and lowers the IPR curve; high skin factor due to wellbore damage, decreasing inflow performance; tubing restrictions; excessive water production, leading to higher fluid density and viscosity; suboptimal well design causing flow inefficiencies; and gas-liquid flow instabilities, which introduce additional pressure losses, particularly at higher production rates (Economides, 2013).

$$P_r - \Delta P_{upstream} = P_{node} \quad (2.1)$$

$$P_{sep} = \Delta P_{downstream} = P_{node} \quad (2.2)$$

Key factors influencing well performance over time include expected productive capacity, pressure drop, and flow rate (Awal and Heinze, 2009). Optimizing the entire system requires integrating all components, often using computer-aided methods like the Integrated Production Modeling (IPM) suite, which employs nodal analysis to generate IPR and VLP curves (Brown and Lea, 1985). The intersection of these curves is termed the solution node, from which node pressure can be estimated by developing pressure relationships for the system's inflow and outflow sections (Ali Altam, 2015). System component changes dynamically affect these curves. Upstream modifications, such as reservoir condition alterations, shift the inflow curve while leaving the outflow curve unchanged. Conversely, downstream changes, like wellhead or separator pressure adjustments, modify the outflow curve without affecting the inflow curve. Fixed pressures, such as reservoir depletion or wellhead conditions, cause simultaneous shifts in both curves (Greene, 1983).

Optimizing well performance requires a thorough understanding of IPR and VLP curve interactions. Identifying and addressing factors that hinder their intersection ensures continued productivity and operational efficiency, underscoring the importance of incorporating advanced modeling tools and methodologies.

2.2 Well Optimization Techniques

The optimization of well locations and production strategies in petroleum engineering is essential for maximizing hydrocarbon recovery and economic efficiency. Over the decades, researchers have developed a range of techniques, evolving from control theory-based methods to advanced metaheuristic and hybrid algorithms. Early works, such as (Virnovsky and Kleppe, 1995),

leveraged control theory to optimize horizontal well placement in thin oil zones. Although these studies demonstrated the potential for enhanced oil production, they often relied on simplified reservoir models. Subsequent advancements, like (Buitrago and Gedler, 1996) nonlinear optimization technique for pressure transient analysis, provided valuable insights into reservoir and well parameters, forming a foundation for modern optimization strategies.

Metaheuristic algorithms, particularly Genetic Algorithms (GAs), have gained prominence for their ability to solve complex, multi-dimensional optimization problems. For instance, (Haque, 2002) demonstrated the effectiveness of GAs in identifying optimal drilling locations, highlighting their adaptability to non-linear and stochastic reservoir conditions. (Razavi and Jalali-Farahani, 2008) proposed an ant algorithm to maximize hydrocarbon production rates, demonstrating its robustness in dealing with stochastic and heterogeneous reservoir conditions.

Data-driven and hybrid approaches have also gained prominence. (Berneti, 2011) combined fuzzy subtractive clustering with Particle Swarm Optimization (PSO) to develop an intelligent model for permeability prediction, achieving high accuracy using well log data. (Akande et al., 2017) further advanced this field by integrating PSO with support vector regression, creating a hybrid model that improved both efficiency and precision in permeability prediction.

These studies underscore the importance of advanced algorithms in optimizing petroleum production processes. However, challenges such as scalability, computational cost, and integration with real-time field data remain areas for future research (Kumar et al., 2021).

Nodal analysis is a powerful technique used in well optimization to improve performance and increase production rates. The concept of dynamic nodal analysis has been introduced as a numerical algorithm for gas well production optimization, offering advantages over classical nodal analysis methods (Bitsindou and Kelkar, 1999). This technique allows for the selection of timing and capacity of surface compressors, evaluation of economic viability of well stimulation, and understanding the impact of individual production components on gas well productivity over its lifespan. In the context of gas well optimization, various optimization techniques have been explored. (Alarco' n et al., 2002) implemented a nonlinear constrained programming approach for global optimization of gas allocation to a group of wells in artificial lift, demonstrating fast convergence and broad application. (Igwilu et al., 2018) reviewed gas well optimization using

production performance models, focusing on determining optimal production rates and lift gas rates to optimize operational objectives. Furthermore, the application of nodal analysis in well optimization has been demonstrated in specific case studies. (Shah et al., 2020) applied nodal analysis to Habiganj Gas Field in Bangladesh, specifically focusing on increasing production rates by optimizing various components in the system. This analysis involved evaluating the inflow performance relationship and vertical lift performance of each component from the reservoir to the outlet pressure of the separator. Overall, nodal analysis techniques play a crucial role in well optimization, offering a systematic approach to improving performance and maximizing production rates. By considering various optimization methods and case studies, researchers and production engineers can make informed decisions to enhance the efficiency and profitability of gas well operations.

2.3 Artificial Lift Techniques

Artificial lift methods play a vital role in the oil and gas industry, allowing for the efficient extraction of resources from wells. Various methods have been developed and optimized over the years to maximize production rates and minimize operational costs. (Clegg et al., 1993) provide a comprehensive comparison of eight major artificial lift methods, including beam pumping, electric submersible pumping, and gas-lift systems, among others. The authors offer practical guidelines for selecting the most suitable method based on performance and operating capabilities. Optimizing gas allocation in continuous flow gas lift systems is essential for maximizing oil production rates. (Buitrago et al., 1996) propose a global optimization technique that combines stochastic domain exploration and heuristic calculations to determine the optimal gas injection rate for a group of wells. Similarly, (Alarco' n et al., 2002), as mentioned previously, also addressed optimal gas injection rates, highlighting the method's adaptability. The selection of the most economical artificial lift method is crucial for operators to realize the maximum potential from oil and gas fields. (Lea and Nickens, 1999) highlight common selection methods and provide examples of cost and profit calculations over time to aid in decision-making. Additionally, (Vazquez-Roman and Palafox-Hernández, 2005) develop a simulation and optimization model for continuous gas lift systems based on mass, energy, and momentum balances, solving differential algebraic equations to optimize gas injection rates. Dynamic programming algorithms have been utilized to optimize lift-gas allocation in gas-lift wells. (Nakashima and Camponogara, 2006)

present a profit maximization algorithm for oil wells producing via gas lift, considering multiple well performance curves and gas injection constraints. Furthermore, (Plucenio et al., 2012) discuss stabilizing gas-lift well dynamics with a free operating point, while (Hussein et al., 2015) focus on designing gain scheduling control strategies for artificial gas lift in oil production. In conclusion, the optimization of artificial lift methods and gas allocation techniques is essential for maximizing oil and gas production rates while minimizing operational costs. Continued research and development in this field are crucial for the efficient extraction of resources from wells in the oil and gas industry.

2.4 Foam Lift Methodology:

Foam lift is an artificial lift strategy employed in aging oil wells to boost oil extraction. This approach involves introducing foam into the wellbore, which decreases the fluid column's density, thus lowering the bottom-hole pressure and facilitating easier oil flow to the surface.

2.4.1 Operational Aspects:

Essential elements of foam lift operations in mature oil wells include:

- Application and purpose:
Primarily utilized in older oil wells where natural reservoir pressure has decreased, impeding oil flow to the surface. This technique is particularly effective in wells with high water-oil ratios, as it improves the efficiency of elevating the water-oil mixture (Ahmad et al., 2017).
- Functional principle:
This process enhances fluid movement by reducing hydrostatic pressure and more effectively elevating the oil-water mixture to the surface. The foam's durability allows it to maintain a low-density structure, improving hydrocarbon recovery even in wells with high water content. Furthermore, the foam helps prevent liquid regression and reduces formation damage by decreasing fluid flow velocity and turbulence. This method is especially advantageous in prolonging the productive lifespan of wells with declining reservoir pressure and challenging fluid compositions (Sunmonu and Onyekonwu, 2013, Tavakkoli et al., 2021).

- Advantages:

When applied to mature oil fields, particularly those experiencing production decline due to reduced reservoir pressure, foam lift offers numerous benefits:

1. Enhanced production rates: The reduction in bottom-hole pressure can significantly increase production rates in mature wells ([Ahmad et al., 2017](#)).
2. Economic efficiency: Foam lift is often more economical than alternative artificial lift methods due to lower equipment and upkeep expenses ([Lake, 1989](#)).
3. Enhanced well efficiency: Foam lift aids in managing wells with high water cuts, improving overall well performance and extending the well's productive duration ([Economides, 2013](#)).
4. Ecological advantages: The use of environmentally friendly foaming agents minimizes ecological impact, making foam lift a more sustainable option ([Romero-Zerón, 2012](#)).
5. Decreased back pressure: By reducing back pressure in the well, foam lift enables more efficient gas and liquid flow to the surface, maintaining stable production levels ([Lake et al., 2014](#)).
6. Improved recovery: Foam lift can enhance the extraction of hydrocarbons from reservoirs that are otherwise challenging to produce ([Alvarado and Manrique, 2010](#)).

2.4.2. Types Of Foam Lift Techniques in Mature Oil Wells:

Various foam lift methods, such as gas-assisted foam lift, chemical foam lift, foam-assisted gas lift, and foam-assisted plunger lift, provide distinct benefits based on specific well conditions. These approaches aid in reducing bottom-hole pressure, stabilizing the wellbore, and enhancing fluid lifting efficiency.

1. **Continuous Foam Injection:** This method involves uninterrupted injection of foam, created by combining a foaming agent with gas (usually nitrogen or carbon dioxide), into the wellbore. By decreasing the fluid column density, it lowers bottom-hole pressure and facilitates oil flow to the surface. This technique is particularly effective in wells with high water cuts, improving the lifting of water and oil mixtures ([Ahmad et al., 2017](#)).

2. **Foam Assisted Gas Lift (FAGL):** This technology utilizes downhole injection of a liquid foamer to decrease the fluid column weight and minimize slippage, thereby improving the well's vertical lift performance. The foamer can be delivered downhole through a pre-installed chemical injection line or into a lift gas stream at the surface ([Okoro et al., 2023](#)).
3. **Gas-Assisted Foam Lift (GAFL):** This method improves liquid removal in mature oil wells by combining gas injection with foam generation. The foam reduces liquid column density and surface tension, enhancing fluid lifting and productivity, particularly in wells with high water cuts or low pressures ([Marques et al., 2024](#)).
4. **Chemical Foam Lift:** This artificial lift technique involves injecting chemical foaming agents into the wellbore to create foam, which decreases the density and surface tension of the fluid column. This reduction aids in lifting fluids to the surface, improving production efficiency in mature oil wells, especially those with high water cuts or liquid loading issues. The foam's stability and reduced liquid holdup contribute to more efficient deliquification and extended well life ([Lea and Nickens, 2008](#), [Lane, 2013](#)).
5. **Foam-assisted Plunger Lift:** This innovative artificial lift technique combines surfactants for foam generation, which reduces hydrostatic pressure in the wellbore, with the mechanical action of a plunger to lift liquids and gas to the surface. This method effectively boosts production in mature oil wells, particularly those with high water cuts, by decreasing back pressure and enhancing flow dynamics. The foam minimizes friction and resistance for the plunger, enabling more efficient fluid lifting and prolonging the well's productive life.
6. **Foam-Assisted Hydraulic Lift:** This artificial lift technique integrates hydraulic pumps with foam injection to enhance fluid recovery in oil wells. In this approach, foaming agents are introduced into the wellbore to generate foam, which reduces the liquid column's density and viscosity. This decrease in fluid density lowers the hydrostatic pressure, facilitating easier lifting of oil and water mixtures to the surface ([Nguyen, 2020](#)).

Table 2.1 Types of Foam Lift Technique

Technique	Primary Purpose	Effect in the Well	Mechanism	Complexity	Substance Combination
Continuous Foam Injection	Reduce bottom-hole pressure, stabilize wellbore, improve fluid lifting	Helps to lift oil and water mixtures efficiently	Continuous injection of foam (gas + foaming agent) reduces fluid density and bottom-hole pressure	Moderate	Gas (e.g., nitrogen or CO ₂) + foaming agent
Foam-Assisted Gas Lift (FAGL)	Improve vertical lift performance and reduce slippage	Enhances fluid lifting by lightening the fluid column	Injection of liquid foamer reduces fluid column density and improves lift efficiency	Moderate to High	Liquid foamer + lift gas
Gas-Assisted Foam Lift (GAFL)	Enhance liquid removal, especially in wells with high water cuts	Improves fluid lifting by reducing liquid column density	Combination of gas injection with foam generation to reduce surface tension and improve lift	High	Gas (e.g., nitrogen or CO ₂) + foaming agent
Chemical Foam Lift	Enhance fluid lifting, especially in wells with liquid loading	Increases lifting efficiency, reduces liquid holdup	Injection of chemical foaming agents creates foam to lower fluid density and surface tension	Moderate to High	Chemical foaming agents
Foam-Assisted Plunger Lift	Enhance fluid removal, reduce back pressure	Reduces friction and resistance for the plunger, improving flow	Foam reduces hydrostatic pressure and friction for plunger movement, enhancing fluid lift	High	Surfactants (foaming agents) + gas
Foam-Assisted Hydraulic Lift	Improve fluid recovery in oil wells	Reduces viscosity and density of the fluid column for easier lifting	Foam injection combined with hydraulic pumps to lift fluid to surface	High	Foaming agents + hydraulic fluids

2.4.3. Specifications

Foam lift is a technique used to boost hydrocarbon production in mature oil fields with high gas-liquid ratios or low reservoir pressures. This method excels at managing liquid loading in gas wells and can be customized for various operational conditions.

Essential Features of Foam Lift Techniques:

Foam composition: Foam typically consists of a mixture of water, surfactant, and gas (such as air, nitrogen, or natural gas) (Tavakkoli et al., 2021). Surfactants are substances that reduce surface tension or interfacial tension between two liquids, a liquid and a gas, or a liquid and a solid. A surfactant, which acts as a foaming agent, contains both polar and non-polar components within a single molecule: a non-polar hydrophobic part and a hydrophilic portion. The surfactant can serve as a linking interface between two immiscible fluids (Barreto et al., 2017). One surfactant from each category (anionic, cationic and non-ionic) was selected. The interfacial characteristics of all chosen surfactants have been thoroughly examined in previous studies, with published literature available (Figure 2.2) (Kawale, 2012).

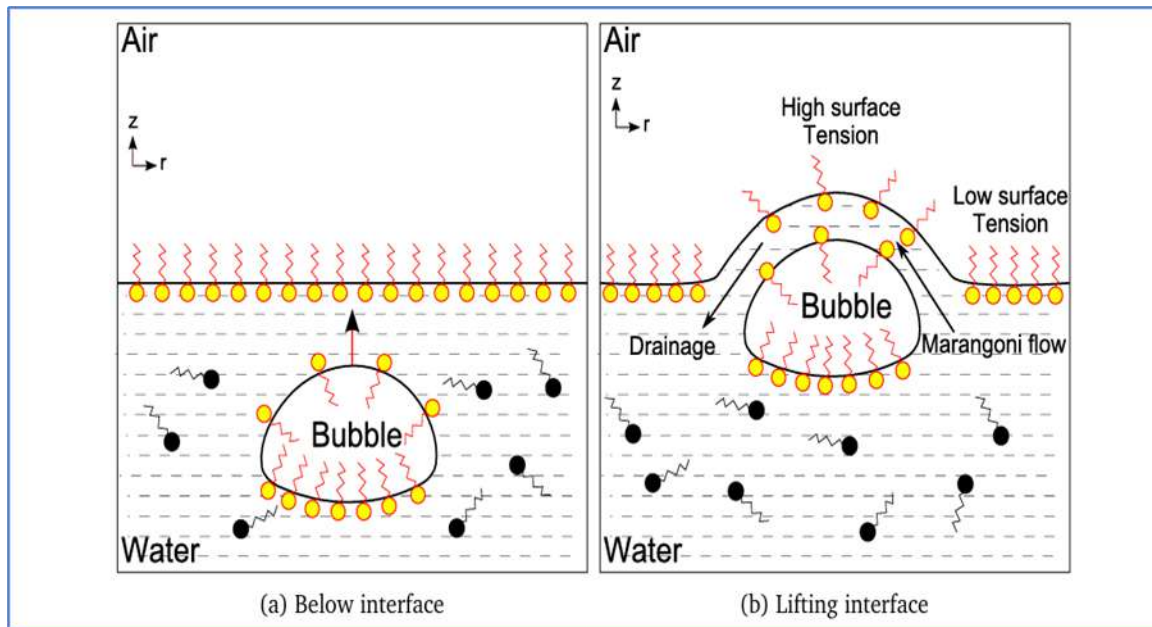


Figure 2.2 Schematic of a bubble rising in surfactant solution. Presence of surfactants creates surface tension gradients when a rising bubble stretches the interface.

Equipment utilized:

- Surface Equipment:

Mixing Tanks: Employed to create surfactant solutions with specific concentrations (Martins et al., 2019).

Pumps: Used to inject the surfactant solution into the wellbore at regulated rates. Accurate pump calibration is crucial for maintaining consistent foam quality during injection (Martins et al., 2019, He et al., 2022).

Compressors: Ensure a constant gas flow for continuous or batch operations (Martins et al., 2019).

- Downhole Equipment:

Foam Diverters: These devices direct foam into specific reservoir zones, optimizing its effectiveness in displacing liquids. Their use enhances sweep efficiency and ensures uniform foam distribution.

Tubing or Coiled Tubing Strings: Transport foam to the desired depth. Coiled tubing is particularly beneficial for deep wells or when precise foam placement is necessary (He et al., 2022).

- Application Techniques:

Continuous Foam Injection: Foam is consistently injected into the wellbore during production to prevent liquid accumulation and ensure efficient lifting. Pumps are used to inject the foam (Martins et al., 2019). The tubing then delivers the foam to the target depth, and foam diverters distribute it across the intended zones. This approach maintains continuous lifting action, decreases hydrostatic pressure, and improves production efficiency. It is especially effective in wells with persistent liquid loading, prolonging the productive lifespan of mature wells with high water cuts.

Batch treatment: Involves periodic foam injection to remove accumulated liquids from the wellbore. Foam is transported through tubing to the accumulation zone, where it reduces liquid holdup and hydrostatic pressure. This method is cost-effective and operationally straightforward, making it ideal for wells with intermittent liquid loading or when artificial lift systems are not in use (He et al., 2022).

2.4.4. Research applied

Foam lift techniques have been successfully implemented in various locations to boost oil production in mature fields. For example, A. Farag and associates conducted a field experiment in an oil-producing facility in The Netherlands, showing that ongoing downhole foam injection could improve production in gas-lifted oil wells with high water cuts (Farag et al., 2016).

In another significant study, Siti Azlynda Ahmad and a team from Shell Malaysia Exploration & Production (SMEP) performed a trial in a mature oil field in Malaysia. By introducing a liquid foamer into the gas lift system, they achieved a 22% rise in gross production rate (Ahmad et al., 2017). This study illustrates how foam-assisted gas lift can enhance production efficiency and prolong the productive lifespan of older wells. Furthermore, combining foam lift techniques with other artificial lift methods, such as gas lift and electrical submersible pumps (ESPs), further improves well performance and alleviates operational challenges.

These applications have also emphasized the use of eco-friendly foaming agents to reduce environmental impact. Through careful selection and testing of environmentally conscious foaming agents, these studies have demonstrated that it is feasible to minimize the ecological footprint while sustaining or even increasing production levels. In summary, the research conducted by Farag et al. and Ahmad et al. offers crucial insights into the practical implementation and advantages of foam lift techniques in the petroleum industry.

2.5. Environmental Consequences:

The ecological effects of foam utilized in oil wells can differ based on the foam type and its usage.

- Above-ground Effects:

Chemical Leaks: Foam may potentially cause chemical leaks on the surface, which could pollute soil and water resources if not handled properly (2023). Atmospheric Pollution: Certain foaming agents might emit volatile organic compounds (VOCs) or other contaminants into the atmosphere, adding to air pollution (2023).

- Below-ground Effects:

Aquifer Pollution: If foam elements seep into the aquifer, they can taint drinking water supplies and damage aquatic ecosystems (2023). Earth Contamination: Foam remnants can impact soil health, possibly affecting plant development and soil microorganisms (2023).

- Enhancing Environmental Friendliness:

Employ polyurethane foam with sustainable, bio-derived materials and water-based formulas to lessen environmental damage (Fulfer, 2024, Sinclair, 2024). Incorporate safer chemicals in foam manufacturing to reduce worker exposure and soil pollution (Harris, 2024). Emphasize decreasing the carbon footprint by utilizing eco-friendly raw materials and minimizing waste (2023). Environmentally conscious raw materials in foam production include bio-based polyols, which are obtained from renewable resources such as vegetable oils, and water-based surfactants, which are less detrimental to the environment. Furthermore, using carbon dioxide (CO₂) as a blowing agent in foam formulation reduces the ecological impact compared to conventional chemical agents. These alternatives help minimize the carbon footprint and potential toxicity, making foam lifting more sustainable (Fulfer, 2024, Sinclair, 2024).

Chapter 3: Simulation and Methodology

This chapter focuses on the application of the PROSPER simulation software to model and analyze the performance of two selected oil wells under natural and foam lift conditions. The aim is to demonstrate how foam lift enhances production efficiency in mature wells by reducing bottom-hole pressure and improving liquid lifting. The chapter begins with a brief overview of the PROSPER simulator and its role in system analysis. It then outlines the modelling steps, including data entry, model calibration, and foam lift implementation. Finally, a case study is presented to evaluate the practical impact of foam injection on well productivity.

3.1 Prosper Simulator

3.1.1 Definition:

PROSPER is part of the IPM toolkit which is used in well performance, design and optimization software. PROSPER software is instrumental in enabling engineers to accurately and swiftly predict tubing and pipeline hydraulics, temperatures, and other critical parameters. This tool is extensively utilized in the analysis of production systems, inflow performance, and artificial lift designs (Ltd, 2019).

Within the oil and gas industry, PROSPER serves several key functions, including:

1. **Well Performance Analysis:** It facilitates the evaluation and optimization of well performance by modeling inflow and outflow behavior.
2. **Production Optimization:** The software enhances production strategies, such as artificial lift designs and nodal analysis.
3. **Pipeline and Tubing Hydraulics:** It forecasts pressure drops and temperature variations in pipeline and tubing systems.
4. **Reservoir Behavior Simulation:** PROSPER models reservoir conditions to assess production potential and devise extraction strategies.
5. **Decision Support:** Equipped with advanced reporting and data visualization tools, it supports informed decision-making to improve efficiency and reduce costs.

The PROSPER program encompasses several applications:

1. Well Performance Modeling

PROSPER facilitates comprehensive modeling of wellbore performance by integrating Inflow Performance Relationships (IPR) with Vertical Lift Performance (VLP) analyses. This integration enables engineers to evaluate and optimize the entire production system, extending from the reservoir to the surface facilities. The software supports various well configurations, including multilateral completions, to accurately represent complex well structures.

2. Artificial Lift System Design

The software provides extensive tools for designing and evaluating artificial lift systems such as gas lift, electrical submersible pumps (ESP), and progressive cavity pumps (PCP). Engineers can simulate different lift scenarios to determine the most effective method for enhancing production, considering factors such as reservoir characteristics and fluid properties.

3. Thermal Modeling

PROSPER includes advanced thermal modeling capabilities, allowing for the simulation of temperature profiles within the wellbore. It offers multiple methods, ranging from simplified constant heat transfer rates to detailed energy balance calculations that account for conduction, convection, and radiation. This feature is crucial for assessing thermal effects on fluid behavior and equipment performance.

4. Flow Assurance Analysis

The software addresses flow assurance challenges by modeling potential issues such as wax and hydrate formation. By predicting these occurrences, engineers can develop mitigation strategies to ensure continuous production and maintain system integrity.

5. Perforation and Completion Design

PROSPER aids in designing well completions and perforations by simulating their impact on well performance. It enables the evaluation of different completion strategies, assisting engineers in optimizing production while minimizing formation damage and sand production.

6. Integration with IPM Suite

As part of the IPM Suite, PROSPER integrates seamlessly with other tools such as GAP (network modeling), MBAL (material balance), and PVTP (fluid characterization). This integration facilitates a comprehensive approach to field development planning and real-time production optimization.

3.1.2 Prosper and System Analysis

3.1.2.1 Introduction to PROSPER

PROSPER is a software tool designed for analyzing and optimizing well performance, created by Petroleum Experts. It is extensively used in the oil and gas sector to model and enhance production systems, encompassing both natural flow and artificial lift techniques. This software enables engineers to craft and assess different production scenarios by simulating the operations of wells and surface facilities.

3.1.2.2 Application of PROSPER in System Analysis

In petroleum engineering, system analysis entails examining the entire production system's performance, spanning from the reservoir to the surface facilities. PROSPER aids in this process by employing nodal analysis, a method that segments the production system into nodes to evaluate pressure losses and enhance production rates. By combining Inflow Performance Relationship (IPR) and Vertical Lift Performance (VLP) curves, PROSPER determines the ideal operating point where the reservoir's inflow aligns with the outflow capacity, thereby optimizing production efficiency ([Odjugo et al., 2020](#)).

3.1.2.4 Case Studies and Applications

Numerous studies have highlighted the success of PROSPER in system analysis and optimizing production. In Libya's Amal Field, PROSPER was employed to enhance an oil well using continuous gas lift by evaluating graphical, mathematical, and software-based approaches. The PROSPER model delivered precise forecasts and supported effective optimization strategies. Likewise, in Bangladesh's Srikail Gas Field, researchers utilized PROSPER for nodal analysis to boost gas output. By modifying parameters like skin factor, reservoir pressure, and tubing

diameter, the study achieved better IPR and VLP responses, resulting in increased production rates (Sharma, 2023)

3.1.2.5 Suitability of PROSPER for Our Case Study

In our project, we are assessing the effectiveness of a well using foam lift, a technique frequently employed to reduce the hydrostatic pressure in the tubing by injecting surfactants or foaming agents, enabling gas to transport liquids to the surface. Although PROSPER lacks a direct built-in foam lift feature, it can accurately simulate foam lift behavior through the gas lift module, which facilitates the modeling of multiphase flow behavior and gas injection into the tubing. This flexibility makes PROSPER a suitable option for our system analysis. Several studies endorse the use of PROSPER for unconventional or modified artificial lift simulations. For instance, Ismail et al. (2018) demonstrated that PROSPER was effective in modeling high water-cut wells using the most precise multiphase flow correlations, even when direct modeling was not available (Weiss et al., 2018).

Likewise, Awal et al. (2009) highlighted how PROSPER's nodal analysis tools significantly improved well performance modeling in complex or matured fields by adapting existing modules creatively (Awal and Heinze, 2009).

In this study, the gas lift module within PROSPER was employed with customized fluid properties to simulate foam-assisted gas lift. This approach models the reduction in hydrostatic pressure due to gas-slug formation, akin to the mechanics of foam lift. We adjusted viscosity, density, and flow behavior parameters to accurately represent the foamy mixture, thereby enabling the evaluation of performance under realistic production scenarios.

This methodology allows us to:

- simulate the reduction in hydrostatic head due to foam presence,
- analyze the impact of injection gas rates on production,
- optimize production under varying foam concentrations and pressures.

PROSPER's capability to generate precise Inflow Performance Relationship (IPR) and Vertical Lift Performance (VLP) curves, along with its sensitivity analysis features, renders it particularly effective in assessing how variations in injection gas rates, tubing size, or wellhead pressure affect

well performance. These functionalities assist in identifying optimal operational conditions for the foam lift system, despite the simulation being conducted through the gas lift module. Additionally, the modular and flexible interface of PROSPER permits engineers to enhance standard functionality through innovative parameter adjustments, a capability well-documented by researchers such as [Rami \(2016\)](#), who explored the use of PROSPER for special case evaluations in his final year project ([Ali Altam, 2015](#)). Therefore, despite the lack of a dedicated foam lift feature, PROSPER remains a highly capable tool for system analysis in our case. By using PROSPER in this way and referencing published academic methods, our work aligns with industry practice and demonstrates practical modeling of complex lift systems using available tools.

3.1.3 Simulation Working Procedure:

The flow diagram below depicts the calculation steps to model well flow system analysis in PROSPER.

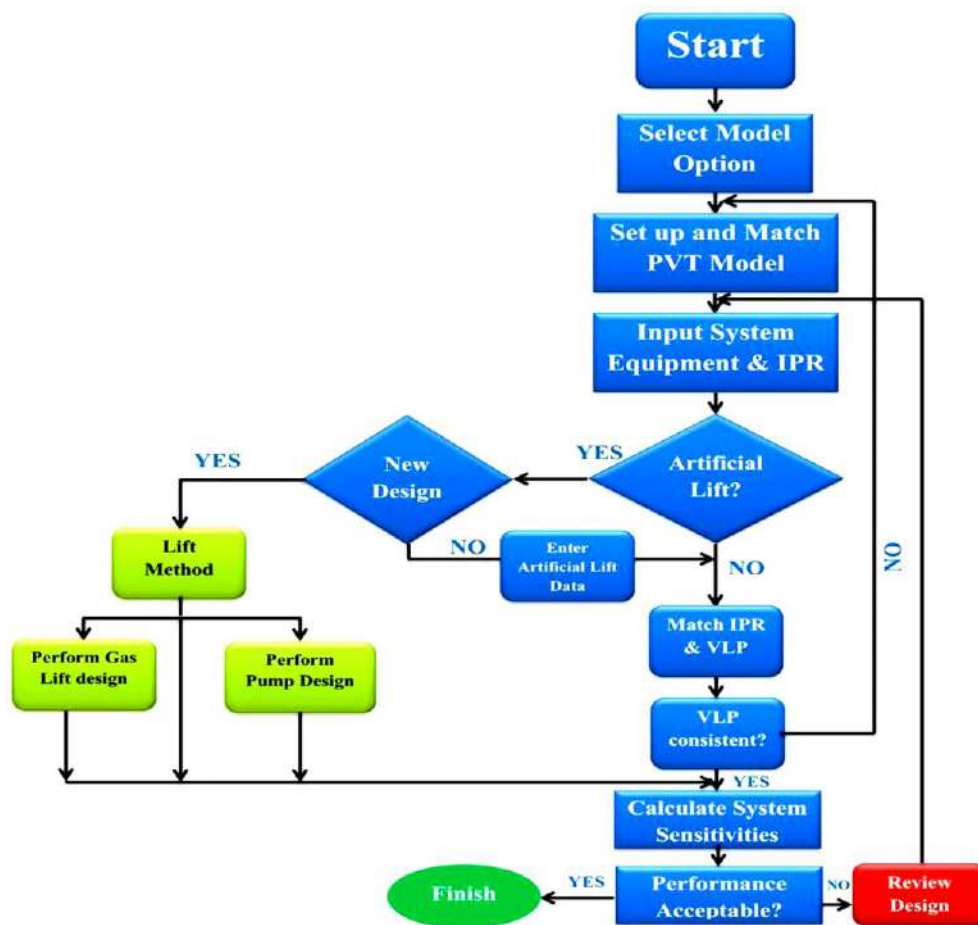


Figure 3.1 PROSPER calculation steps (IPM-PROSPER manual, 2010)

Step 1: System Summary Configuration

Define the well system, including fluid type, reservoir setup, well type, and separator configuration using the System Summary and Options in PROSPER., as shown in Figure 3.2.

System Summary (untitled)

Buttons: Done, Cancel, Report, Export, Help, Datestamp	
Fluid Description	
Fluid	Oil and Water
Method	Black Oil
Separator	Single-Stage Separator
Emulsions	No
Hydrates	Disable Warning
Water Viscosity	Use Default Correlation
Viscosity Model	Newtonian Fluid
Calculation Type	
Predict	Pressure and Temperature (offshore)
Model	Rough Approximation
Range	Full System
Output	Show calculating data
Well	
Flow Type	Tubing Flow
Well Type	Producer
Well Completion	
Type	Cased Hole
Sand Control	None
Artificial Lift	
Method	Gas Lift (Continuous)
Type	No Friction Loss In Annulus
Reservoir	
Inflow Type	Single Branch
Gas Coning	No
User information	
Company	Al-Kitab Uni
Field	Kitab
Location	
Well	K-01
Platform	
Analyst	Osama, Safa, Saja
Date	Saturday, April 11, 2026
Comments (Ctrl-Enter for new line)	

Figure 3.2 System Summary

Step 2: Inputting PVT Data

Input fluid properties using the Black Oil model. Select appropriate correlations for bubble point, viscosity, and volume factors (e.g., Glaso and Beggs). See Figures 3.3 and 3.4.

PVT - INPUT DATA (K-01+Foamer Gaslift.An1) (Oil - Black Oil matched)

Done Cancel Tables Match Data Regression Correlations Calculate Save Open Composition Help

☐ Use Tables Export

PVT is MATCHED

Input Parameters

Solution GOR	231	scf/STB
Oil Gravity	32	API
Gas Gravity	0.83	sp. gravity
Water Salinity	85000	ppm

Correlations

Pb, Rs, Bo	Glaser
Oil Viscosity	Beggs et al

Impurities

Mole Percent H2S	0	percent
Mole Percent CO2	0	percent
Mole Percent N2	0	percent

Figure 3.3 PVT data input

PVT - Correlation Parameters (K-01+Foamer Gaslift.An1) (Oil - Black Oil matched)

Done Cancel Main Export Report Reset All Help

Bubble Point

	Glaser	Standing	Lasater	Vazquez-Beggs	Petrosky et al	Al-Marhoun
Parameter 1	0.92893	0.995	1.10338	0.8903	1.04909	0.93662
Parameter 2	-78.2132	-4.7626	80.4444	-132.813	42.0428	-68.5031
Std Deviation						
	Reset	Reset	Reset	Reset	Reset	Reset

Solution GOR

	Glaser	Standing	Lasater	Vazquez-Beggs	Petrosky et al	Al-Marhoun
Parameter 1	1.79878	1.50925	1.20835	1.9649	3.5706	1.72804
Parameter 2	0.42615	22.2001	21.5349	27.6665	-362.698	42.3661
Std Deviation	17.4744	26.9742	20.8503	26.8152	57.0296	34.75
	Reset	Reset	Reset	Reset	Reset	Reset

Oil FVF

	Glaser	Standing	Lasater	Vazquez-Beggs	Petrosky et al	Al-Marhoun
Parameter 1	1.1094	0.93537	0.94212	0.94335	1.51743	0.95363
Parameter 2	-0.094558	0.080355	0.072708	0.053826	-0.56552	0.17993
Parameter 3	1	1	1	1	1	1
Parameter 4	1e-8	1e-8	1e-8	1e-8	1e-8	1e-8
Std Deviation	0.023167	0.022371	0.019687	0.021382	0.008346	0.018884
	Reset	Reset	Reset	Reset	Reset	Reset

Oil Viscosity

	Beal et al	Beggs et al	Petrosky et al	Egbogah et al	Bergman-Sutton
Parameter 1	0.085429	0.022461	0.1477	-1.9188	-0.13254
Parameter 2	1.34799	1.11979	0.97015	16.0069	1.4629
Std Deviation	0.44124	0.12347	0.1783	0.13046	
	Reset	Reset	Reset	Reset	Reset

Figure 3.4 PVT correlation parameters

Step 3: Inflow Performance (IPR) Data

Configure the IPR using the Vogel equation. Input reservoir pressure, temperature, GOR, water cut, and productivity index. See Figures 3.5 and 3.6.

Figure 3.5 IPR data input

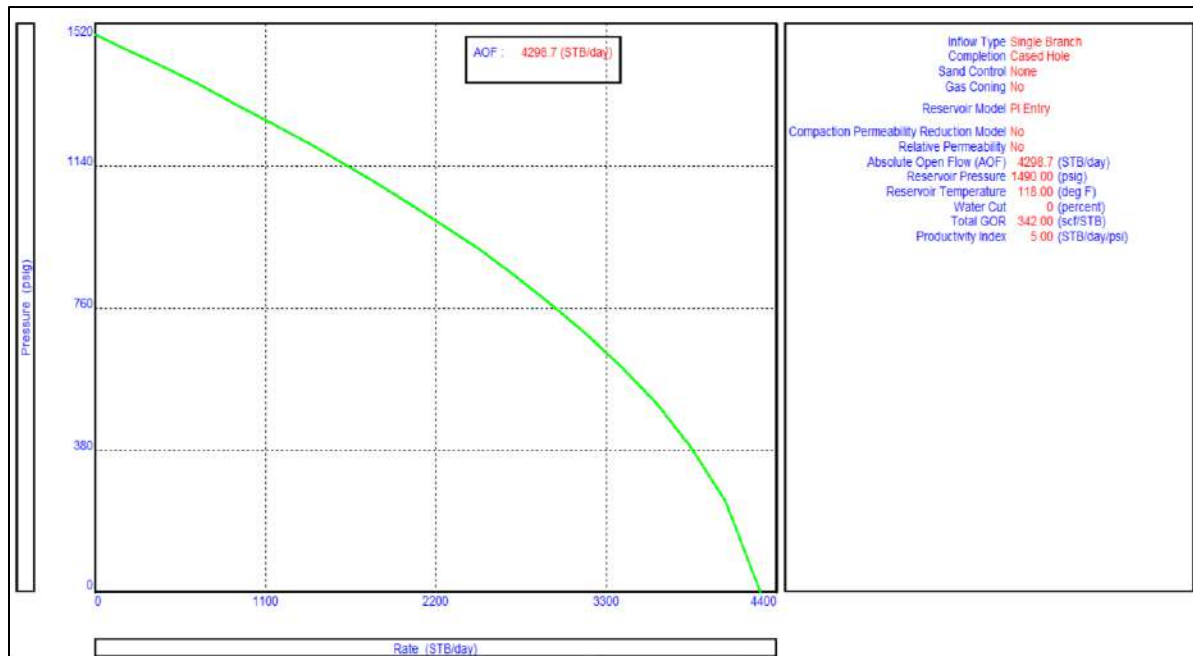


Figure 3.6 IPR plot result

Step 4: Continuous Gas Lift Input

Set the gas lift method (e.g., continuous, fixed depth injection), and align gas properties with PVT data. Choose injection parameters. As shown in Figure 3.7.

GASLIFT INPUT DATA (K-01+Foamer Gaslift.Anl)

Buttons: Done, Cancel, Export, Report, Help

Input Data

GasLift Gas Gravity	0.75	sp. gravity
Mole Percent H2S	0	percent
Mole Percent CO2	0	percent
Mole Percent N2	0	percent
GLR Injected	250	scf/STB
Injected Gas Rate	1	MMscf/day
GLR/Rate ?	Use GLR Injected Use Injected Gas Rate	

Gaslift Details

Gaslift Valve Depth (Measured)	2550	feet

Gas Lift Method

Fixed Depth of Injection
Optimum Depth of Injection
Valve Depths Specified

Figure 3.7 Gaslift input data

Step 5: Equipment Data Input

Enter downhole and surface equipment details including tubing/casing dimensions, well type, and flow settings. Tubing and casing dimensions were selected using PROSPER's internal pipe database as illustrated in Figures 3.8 and 3.9.

EQUIPMENT DATA (K-01+Foamer Gaslift.Anl)

Input Data

☐ ☐ Deviation Survey

☐ ☐ Surface Equipment

☐ ☐ Downhole Equipment

☐ ☐ Geothermal Gradient

☐ ☐ Average Heat Capacities

Disable Surface Equipment

Figure 3.8 Equipment data

DOWNHOLE EQUIPMENT (K-01+Foamer Gaslift.Anl)

Input Data

	Label	Type	Measured Depth (feet)	Tubing Inside Diameter (inches)	Tubing Inside Roughness (inches)	Tubing Outside Diameter (inches)	Tubing Outside Roughness (inches)	Casing Inside Diameter (inches)	Casing Inside Roughness (inches)	Rate Multiplier
1		Xmas Tree	0							
2		Tubing	3051	2.992	0.0006					1
3		Casing	3210					6.5	0.0006	1
4										
5										
6										
7										
8										
9										
10										
11										
12										
13										
14										
15										
16										
17										
18										

Figure 3.9 Downhole equipment

Step 6: Calculation Summary

Run system calculations for pressure, temperature, and flow performance. Generate key outputs such as system curves and performance plots, as shown in Figure B-9 in Appendix. See Figure 3.10 for correlation comparison between (a) Beggs & Brill, (b) Duns & Ros, and (c) Hagedorn & Brown correlation. See Figures 3.11-13 for system plot and Pressure vs depth plots.

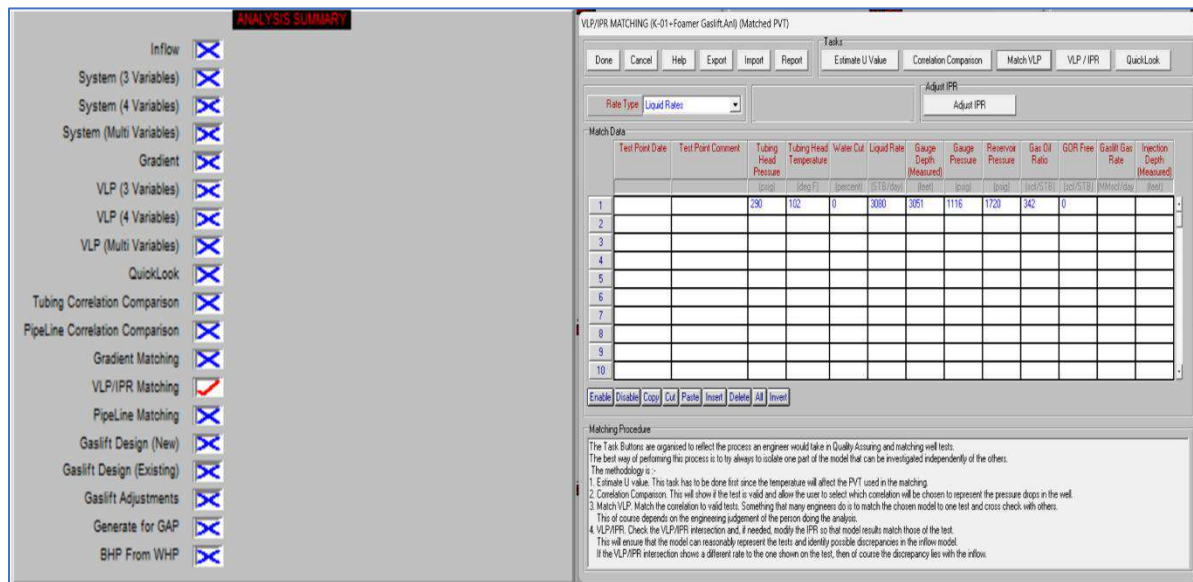


Figure 3.10 Calculation summary

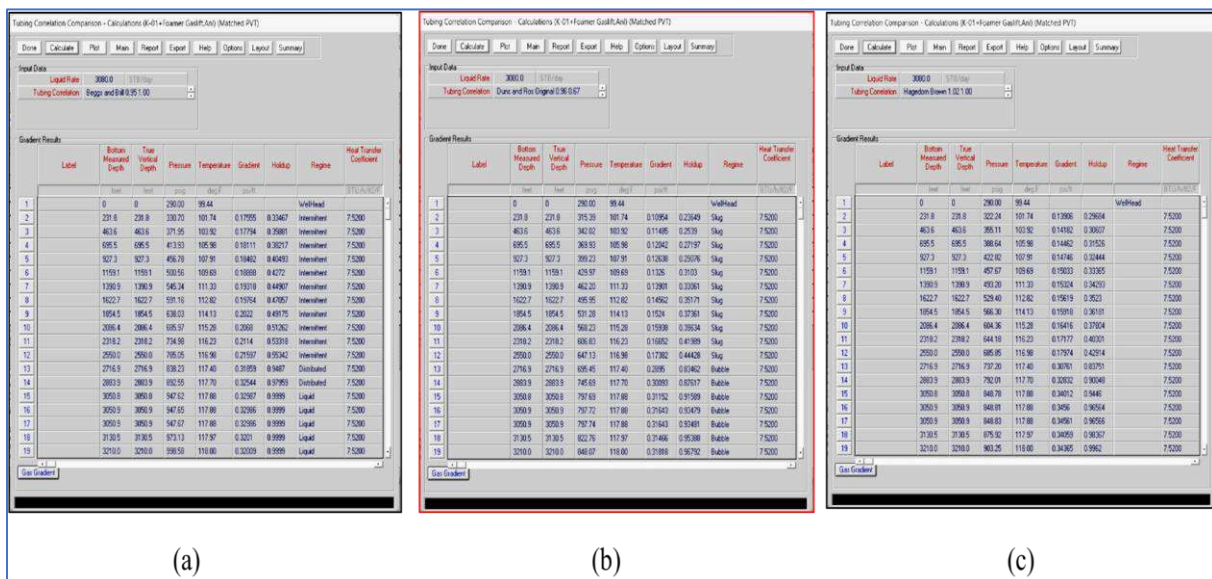


Figure 3.11 Tubing correlation comparison – calculations

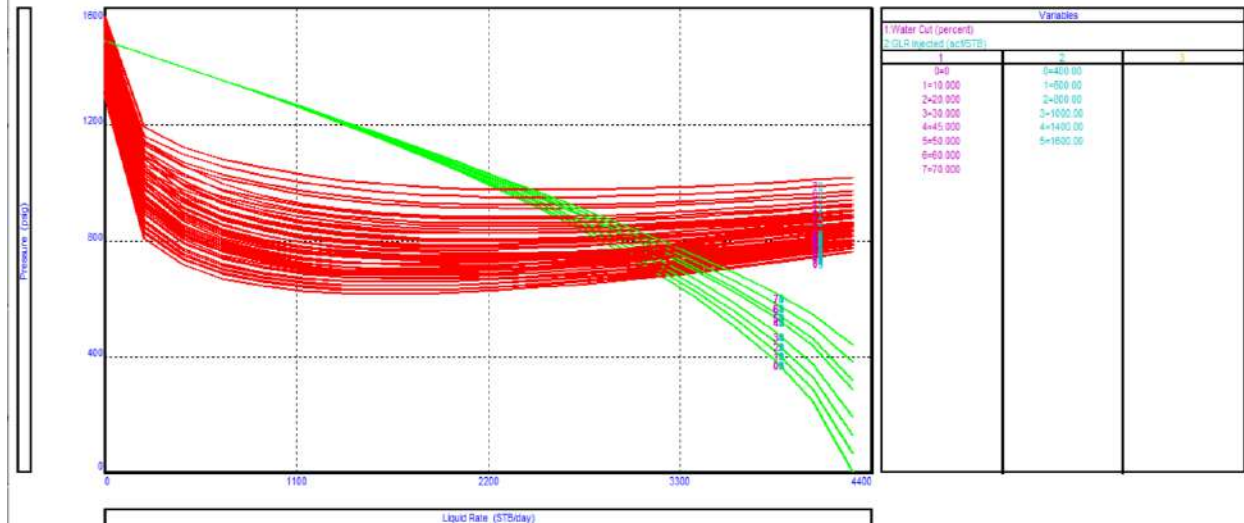


Figure 3.12: System plot showcasing Inflow (IPR) vs Outflow (VLP)

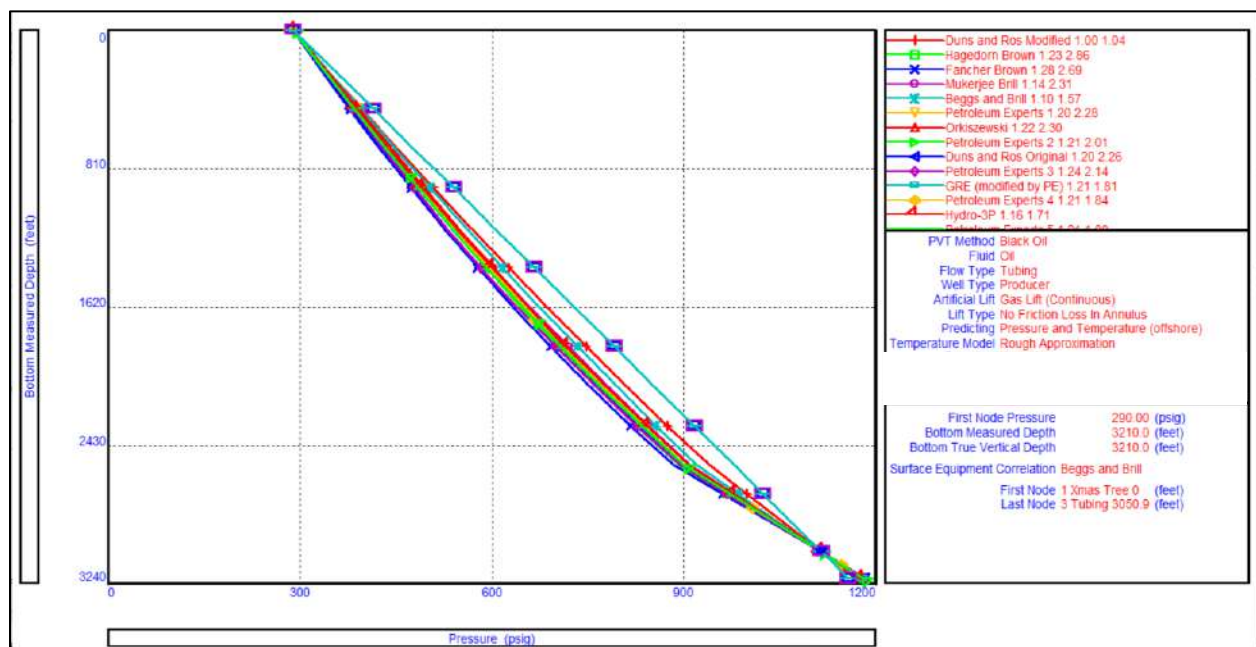


Figure 3.13: Tubing correlation comparison. Preseasure vs measured depth plot

3.3 Case Study:

In this case study is introduced in order to show the effect of foam lift on production deliverability.

3.3.1 Well K-01

Table 3.1 Input Data

Fluid Modeling Data				
Solution GOR		231	SCF/STB	
Oil Gravity		32	API	
Gas Gravity		0.83	Sp. gravity	
Water Salinity		85000	Sp. gravity	
Impurities	H ₂ S	0	percent	
	CO ₂	0	percent	
	N ₂	0	percent	
PVT Match Data				
Point	Pressure, <i>psi</i>	GOR <i>SCF/STB</i>	Oil FVF	Oil Viscosity
1	450	212	1.14	1
2	600	248	1.15	1.1
3	750	282	1.16	1.2
4	942	342	1.17	1.3

Deviation Survey	
Measure Depth	True Vertical Depth
0	0
3210	3210

Geothermal Gradient		
Formation Measured Depth	Formation Temperature (°F)	Overall Heat Transfer Coefficient
0	60	7.52
3210	118	

Well: K-01								
Inflow Performance Data			Down-hole Equipment					
Reservoir Model			Type	Measured depth (ft)	Tubing inside diameter (inch)	Tubing inside roughness (inch)	Casing inside diameter (inch)	Casing inside roughness (inch)
Pressure	1490	psi	Xmas Tree	0				
Temperature	118	°F	Tubing	3051	2.99	0.0006		
Water Cut	0	%	Casing	3210			6.5	0.0006
Total GOR	342	SCF/STB						
PI	5	STB/Day/Psi						
Top Node Pressure	290	Psi						
Well Test Data								
Tubing Head Pressure (psig)	Tubing Head Temperature °F	Water cut %	Liquid rate STB/day	Gauge Depth Measured (m)	Gauge pressure psig	Reservoir pressure psi	GOR SCF/STB	GOR free SCF/STB
290	102	0	3080	3051	1116	1720	342	0

Chapter 4: Results and Discussion

This chapter presents a comprehensive evaluation of natural flow limitations and the application of foam injection as an artificial lift method in mature oil wells. Focusing on the case study from the Kurdistan region of Iraq, it begins with an assessment of natural flow under varying water cut conditions to determine the critical point at which production ceases. The chapter then transitions into an in-depth analysis of foam sensitivity, investigating how foam injection can enhance production performance by reducing fluid column density, improving flow stability, and extending the economic life of wells. Sensitivity studies explore the effects of API gravity and gas-liquid ratio (GLR) on well deliverability, both in dry conditions and in the presence of high-water cuts. Using PROSPER simulations, this chapter quantifies the benefits of foam-assisted lift and highlights its potential as a viable solution in challenging reservoir conditions.

4.1. Natural Flow case Studies

Natural flow describes a reservoir's capacity to bring fluids to the surface using only the energy stored within it, without relying on artificial lift systems. This section examines the case study—Well K-01 under natural flow conditions to assess the impact of different water cut levels on their production performance. The aim is to pinpoint the critical water cut threshold where natural flow stops and to explore the potential of foam injection in prolonging productive life. The well is situated in the Kurdistan region of Iraq and exemplify mature oil-producing reservoirs typical of the area. They vary in depth, gas-oil ratio (GOR), and fluid characteristics such as API gravity and gas composition, which affect their flow capabilities. Well K-01 is at a moderate depth and maintains relatively stable flow at lower water cut levels.

An increase in water cut raises the average density of the produced fluid column, thereby elevating the hydrostatic pressure within the wellbore. According to insights drawn from the literature, this heightened pressure can exceed the available bottomhole pressure especially in depleted or mature reservoirs creating a condition where the natural drive is insufficient to lift fluids to the surface, ultimately impairing well performance.. By analyzing IPR/VLP curves and performance tables, this study quantifies production behavior as water cuts increase for the well. The objective is to outline the operational boundaries of natural flow and pave the way for foam injection as a strategy to overcome these challenges.

4.1.1 Well K-01

Water cut is a critical parameter that significantly influences the flow performance of oil wells. As the water cut increases, the mixture of oil and water in the production stream becomes denser, thereby exerting a greater hydrostatic pressure on the wellbore. When the water cut reaches a certain threshold, the bottomhole pressure (BHP) may become insufficient to overcome the weight of the fluid column, resulting in a cessation of natural flow and, consequently, a halt in production.

Well K-01 natural flow with zero water cut shown below Figure 4.1. Further detail previously shown in Chapter (3). System capacity of Well K-01 at 0% water cut under natural flow indicates an oil rate of 1512 STB/day and at a bottom hole pressure of 1167.81 psig.

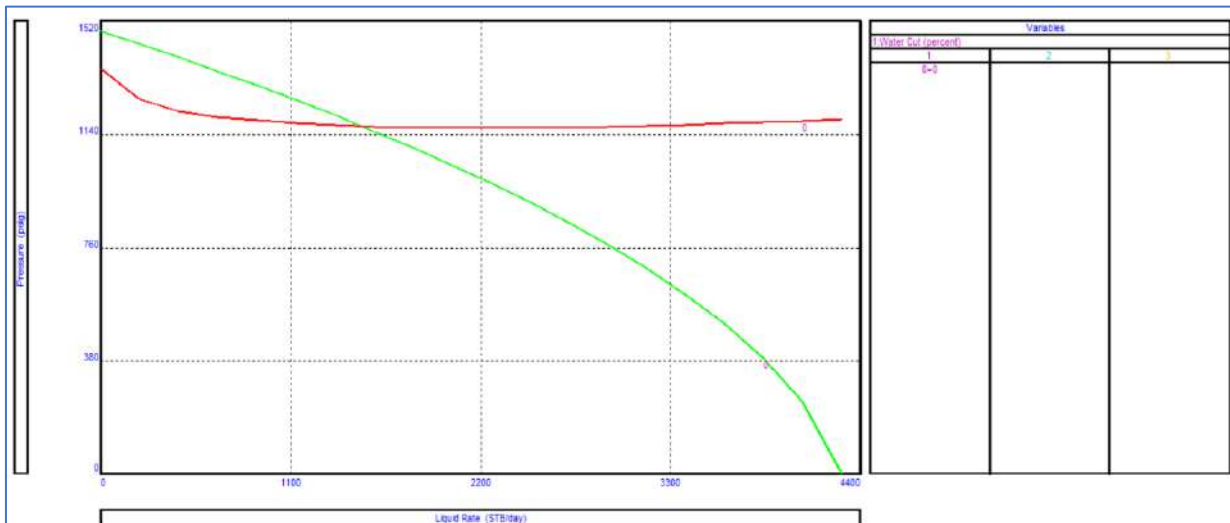


Figure 4.1 Well K-01 zero water cut %, natural flow

Figure 4.2 presents the Inflow Performance Relationship (IPR) and Vertical Lift Performance (VLP) curves for Well K-01 at varying water cut levels ranging from 0% to 70%.

For Well K-01, natural flow is observed to stop when the water cut exceeds approximately 44.845%. The primary mechanism behind this phenomenon is the increased density of the fluid column, which renders the BHP inadequate to lift the fluids to the surface. To mitigate this issue and extend the production capability of the well beyond the natural flow limit, the implementation of foam injection is recommended. As discussed in Chapters 1 and 2, foam serves to reduce the overall density of the fluid column by incorporating gas bubbles within the liquid phase, thereby aiding the BHP in lifting fluids to the surface and sustaining.

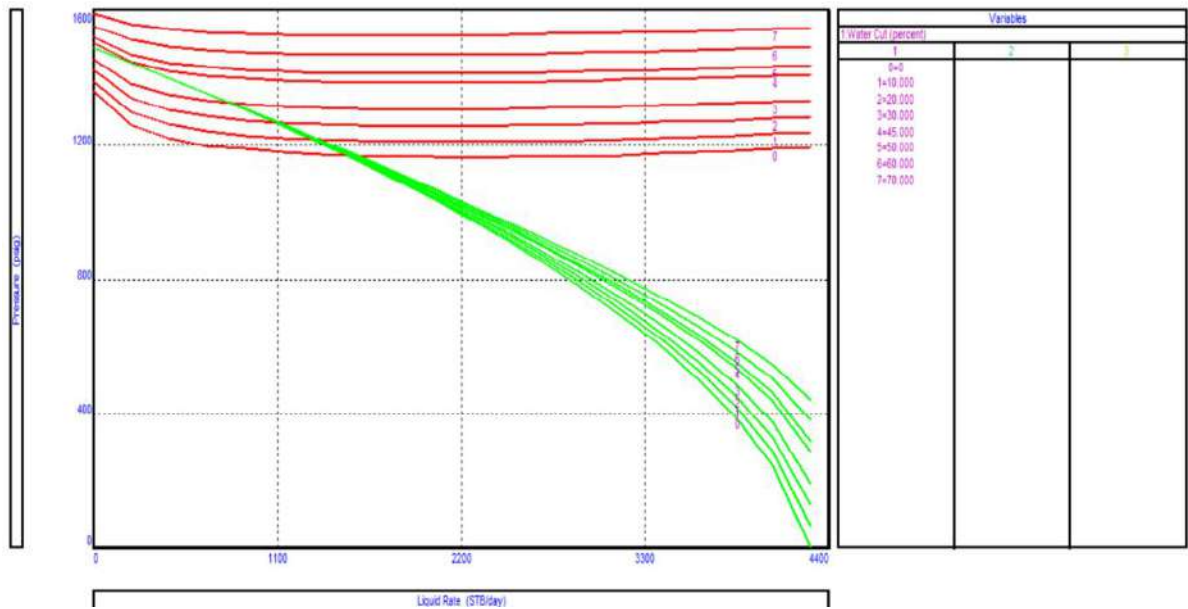


Figure 4.2 Well K-01 Natural flow with suggested water cut %

When the water cut increases, the IPR curve shifts upward, reflecting the increased resistance to flow. Beyond the critical water cut value, the IPR and VLP curves no longer intersect, indicating that the well is unable to flow naturally. This loss of intersection signifies a condition in which the fluid column exerts pressure exceeding the BHP, effectively preventing fluid production. Foam injections are thus proposed as a viable solution to reduce fluid column density and restore flow.

Table 4.1 present the flow performance data for Well K-01 across varying water cut levels. These datasets illustrate the progressive decline in production rates as water cut increases, culminating in flow cessation beyond the respective threshold values in the absence of artificial lift.

Table 4.1 Well K-01 Natural flow

Well K-01 Natural Flow				
Water cut %	System capacity		Pwf (solution node pressure) psig	Gas rate MMscf/day
	Oil rate STB/day	Water rate STB/day		
0	1512	0	1167.81	0.5171
10	1176.1	130.7	1216.98	0.40224
20	867	216.8	1267.35	0.29652
30	566.8	242.9	1326.04	0.19385
44.844	126.9	103.2	1443.97	0.043413
44.845	-	-	-	-
45	-	-	-	-
50	-	-	-	-
60	-	-	-	-
70	-	-	-	-

The analysis of well K-01 under natural flow conditions reveals a shared critical limitation—well production when water cut surpasses approximately 44.8%, due to increased fluid column density and insufficient bottomhole pressure. These findings underline the necessity of artificial lift solutions to extend productive life.

The following section investigates how foam-assisted gas lift can address these challenges by reducing fluid density and stabilizing multiphase flow. Through sensitivity analyses of API gravity and gas-liquid ratios, the performance gains achievable with foam injection in both dry and water-laden conditions are systematically evaluated.

4.2. Foam Assist Gas-Lift

This section delves into how foam injection influences well performance through various sensitivity analyses. The primary aim is to assess the impact of foam on flow stability, lift efficiency, and production under different operational scenarios. This section particularly

emphasizes the influence of API gravity and gas-liquid ratio (GLR) in foam-assisted conditions. By investigating diverse fluid and gas scenarios, we seek to comprehend how foam enhances oil recovery and broadens the flow envelope in aging wells.

The quality of crude oil, indicated by API gravity, significantly affects foam performance. Lighter oils, which have a higher API, typically facilitate better flow due to their lower viscosity and greater mobility. Simulation outcomes from both wells indicate that foam injection is more effective at higher API gravities, especially under water cut conditions, where heavier fluids usually impede flow. In such situations, foam helped to restore production and sustain favorable flow regimes even as water saturation increased.

The well under study is situated in the Kurdistan region of Iraq and were modeled using PROSPER software. Foam-assisted production was simulated over a GLR range of 300–500 SCF/STB for the well, with water cut conditions varying from 0% to 45% for Well K-01. The results demonstrate that foam consistently enhances performance by minimizing pressure losses and stabilizing flow. This underscores foam's vital role in supporting production in mature oil wells, particularly when conventional methods become less effective due to reservoir maturity or challenges associated with multiphase flow.

4.2.1. API Gravity

In this section, we present a comprehensive analysis of the effect of foam injection on API gravity and production performance, specifically focusing first on the well under dry conditions (without water cut). Using PROSPER software, we simulated various production scenarios for the selected well, modelling both natural flow and foam-assisted artificial lift. The primary objective is to evaluate how foam injection enhances oil quality—as indicated by an increase in API gravity—and improves overall production efficiency in mature oil wells. This analysis highlights how foam improves fluid properties and boosts oil quality in the absence of water production. Supporting charts and simulation results are provided to clearly illustrate these effects.

To evaluate the effect of foam injection on the production behavior of Well K-01 under dry conditions, four production scenarios were modeled using PROSPER, each representing a different crude oil quality with API gravities of 32, 40, 45, and 50. The inflow performance relationship (IPR) and vertical lift performance (VLP) curves were analyzed to assess how increasing oil

gravity enhanced by foam injection alters the well's fluid deliverability. The following figures illustrate the effect of foam injection at each API level, without any water cut. These charts clearly demonstrate how foam performance and production efficiency vary with changes in oil quality under dry production conditions.

Table 4.2 Foam Injection Results – Well K-01- API gravity

Well	Condition	API Gravity	Liquid Rate (STB/day)	Gas Rate (MMSCF/day)	Observation
K-01	Dry	32	1512.0	0.5171	Baseline – natural condition, low API results in limited inflow and efficiency.
K-01	Dry	40	1755.4	0.8003	Foam improves oil quality and increases production (~16% gain).
K-01	Dry	45	1772.0	0.8022	Marginal production gain, diminishing returns observed.
K-01	Dry	50	1732.4	0.5924	Slight production drop; lighter oil may reduce drive energy.
K-01	45% Water Cut	32	0.0	0.0	No flow – combination of heavy oil and water blocks production.
K-01	45% Water Cut	40	510.8	0.0	Production starts; foam begins to work despite water.
K-01	45% Water Cut	45	619.9	0.0	Improved flow due to lighter oil and better gas control.
K-01	45% Water Cut	50	722.1	0.0	Best output under wet conditions – high API aids foam.

Figure 4.3. represents the natural state of the well, before any foam injection. The relatively lower API gravity indicates heavier oil, leading to higher friction losses and lower production efficiency. The intersection of IPR and VLP curves occurs at a lower flow rate, suggesting limited inflow capability and reduced deliverability.

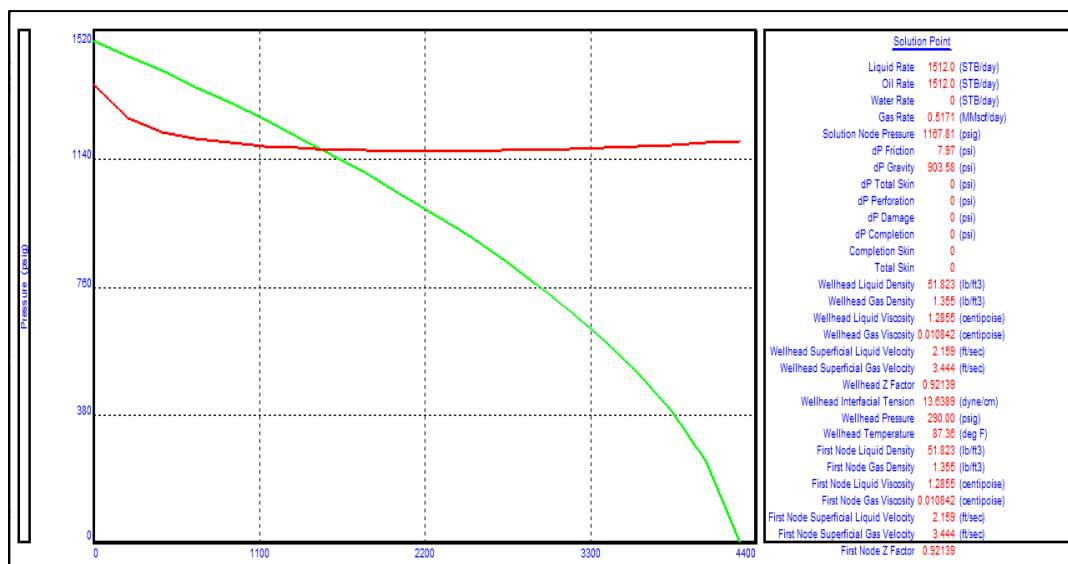


Figure 4.3 API 32 (Baseline – Natural Condition)

Observation: After foam injection, the API gravity increases to 40, indicating an improvement in oil quality (lighter fluid). This results in a noticeable uplift in liquid production by approximately 16%, attributed to the foam reducing gas mobility and improving fluid distribution. The IPR/VLP intersection shifts to a higher rate, showing enhanced flow efficiency as it is shown in Figure 4.4

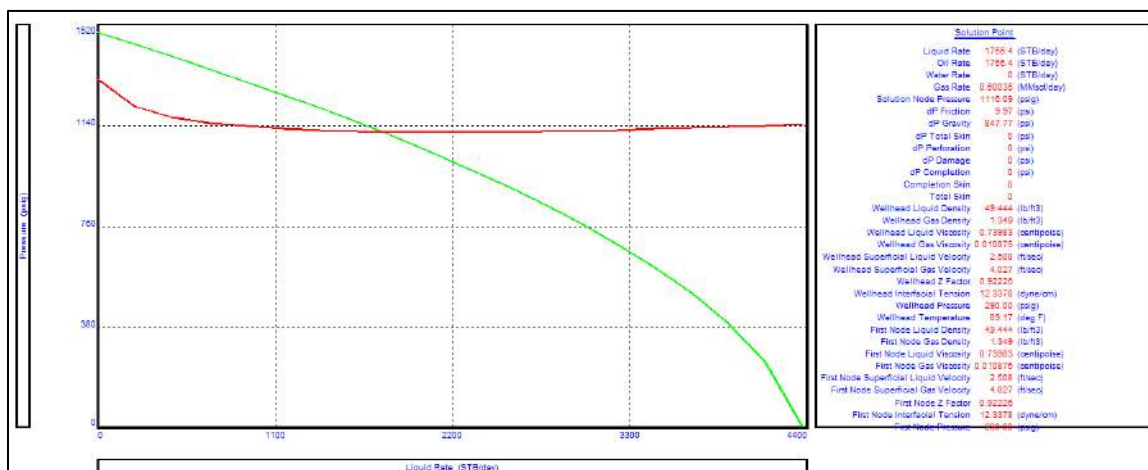


Figure 4.4 Well K-01 effect of API changes, API 40

Further API improvement to 45 slightly increases the production rate. Although the gain is moderate, it reflects the diminishing returns of foam injection at higher API gravities. However, reduced fluid viscosity and enhanced relative permeability to oil still contribute to marginal flowrate improvements as it is shown in Figure 4.5.

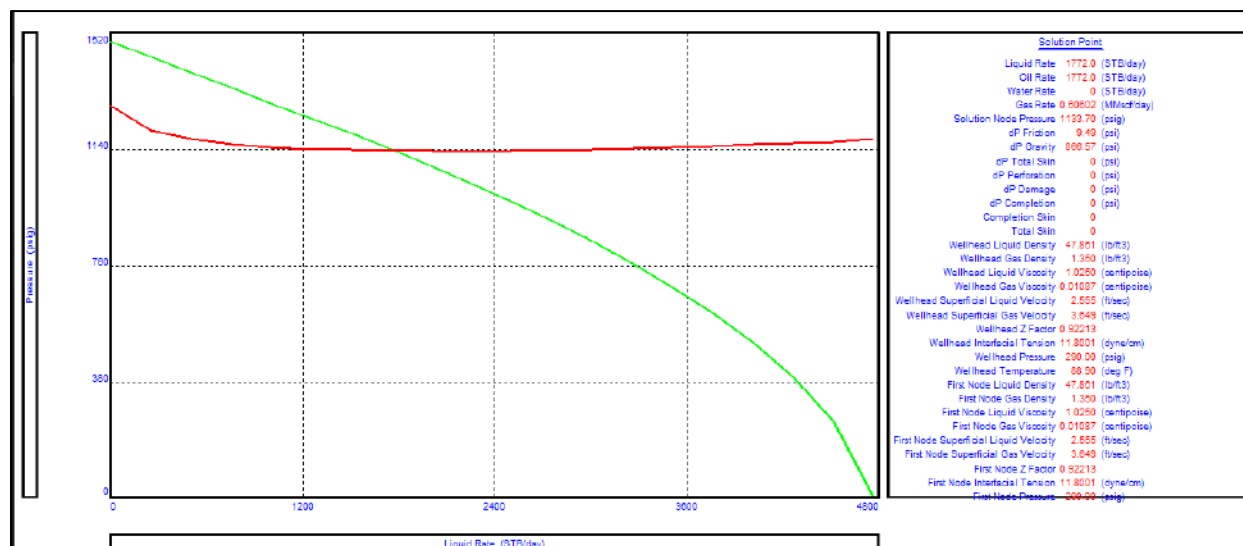


Figure 4.5 Well K-01 effect of API changes, API 45

At API 50, the production rate slightly drops compared to API 45. This suggests a potential stabilization point where further lightening of oil (via foam action) may not significantly enhance flowrate or may be offset by reduced drive energy or increasing GOR. The VLP curve indicates a slightly steeper pressure drop, possibly due to lower fluid density.

Effect of Foam Injection on API Gravity with 45% Water cut – Well K-01, in **Error! Reference source not found.** To assess the performance of foam injection under water-producing conditions, the same four API gravity scenarios (32, 40, 45, and 50) were re-evaluated for Well K-01 using PROSPER simulation, this time with 45% water cut. The goal is to understand how the presence of water influences foam effectiveness in enhancing oil quality and flow behavior.

At a low API gravity of 32 and with 45% water cut, the well fails to produce. The IPR and VLP curves do not intersect, indicating that the pressure drop in the tubing cannot overcome the resistance in the system. This suggests that at lower oil quality, the combination of heavy oil and water severely reduces the effectiveness of foam and overall, well deliverability as it is shown in 4.6.

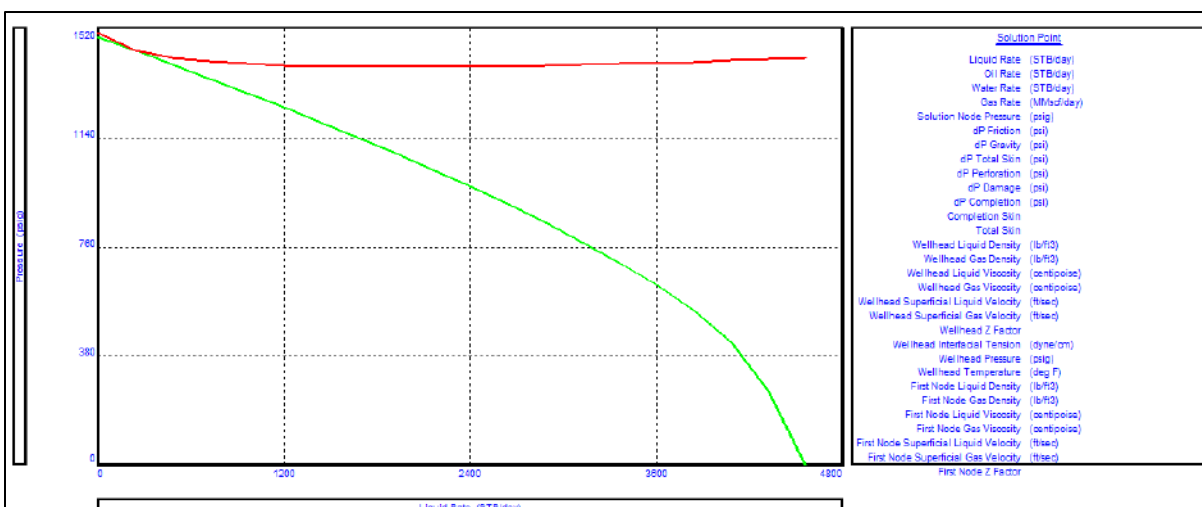


Figure 4.6 API 32 – No Flow Observed

With API increased to 40, foam injection begins to show effectiveness even in the presence of water cut. The intersection of IPR and VLP reappears, enabling production. However, the total flowrate remains limited due to the water presence, which adds friction and reduces overall mobility, highlighting the partial success of foam in overcoming multiphase flow challenges. as it is shown in Figure 4.7.

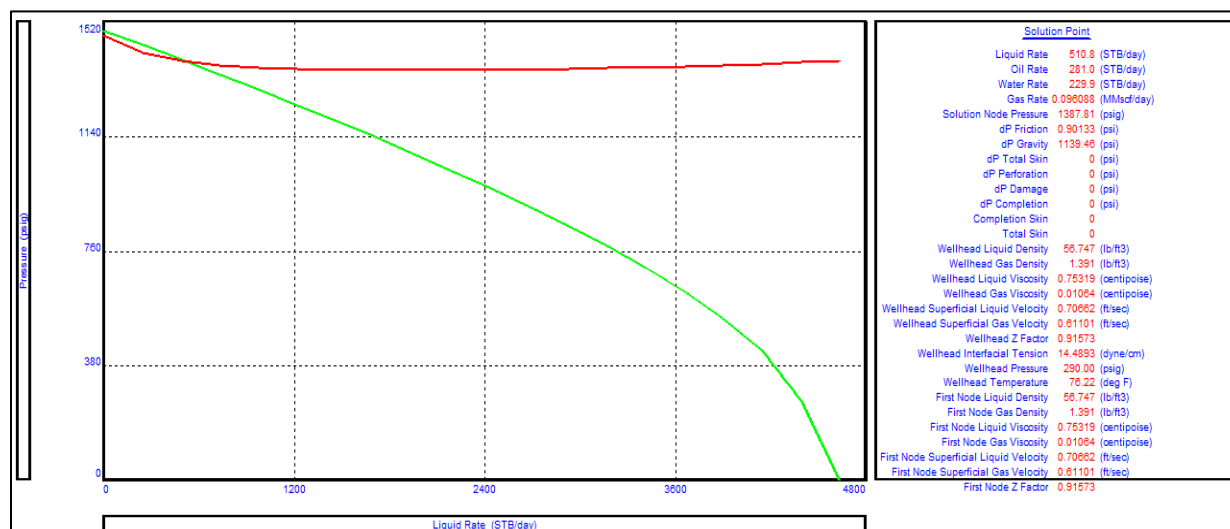


Figure 4.7 API 40 water cut 45%

At 45 API level, foam shows improved performance, with a ~21% increase in liquid rate compared to API 40. The lighter oil improves fluidity, while foam helps in controlling gas mobility and

maintaining flow stability. Despite the water cut, production becomes more favorable due to better oil-water separation and lower emulsion tendencies. as it is shown in Figure 4.8.

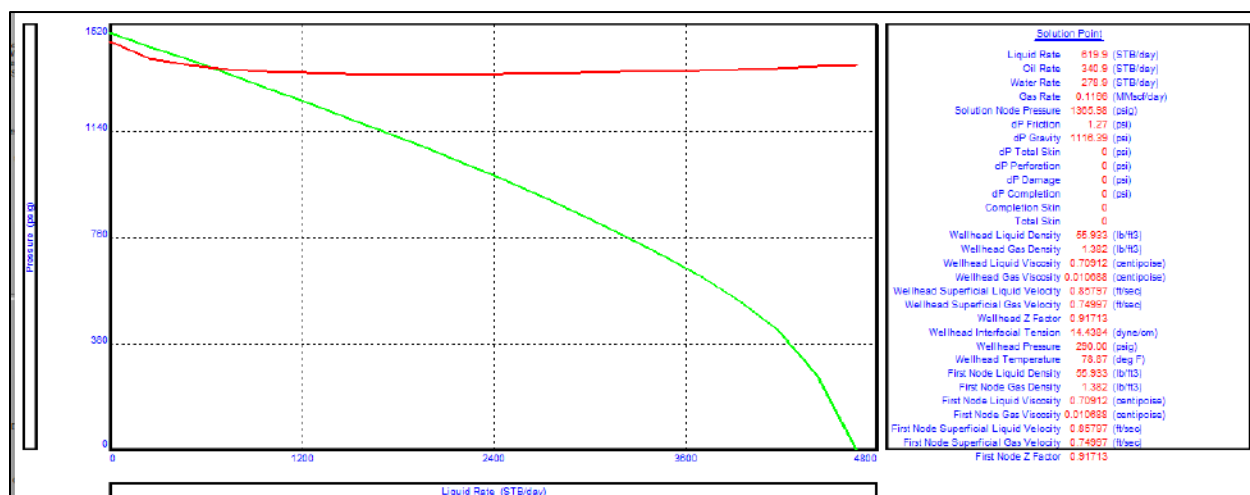


Figure 4.8 API 45 water cut 45%

The best performance under water cut conditions is observed at API 50. The foam injection, combined with high oil quality, leads to a significant production increase. Although the water cut remains at 45%, the improved flow characteristics of lighter oil reduce the adverse impact of water on system hydraulics. This demonstrates foam's synergy with high API gravity in optimizing flow in wet reservoirs. as it is shown in 4.9.

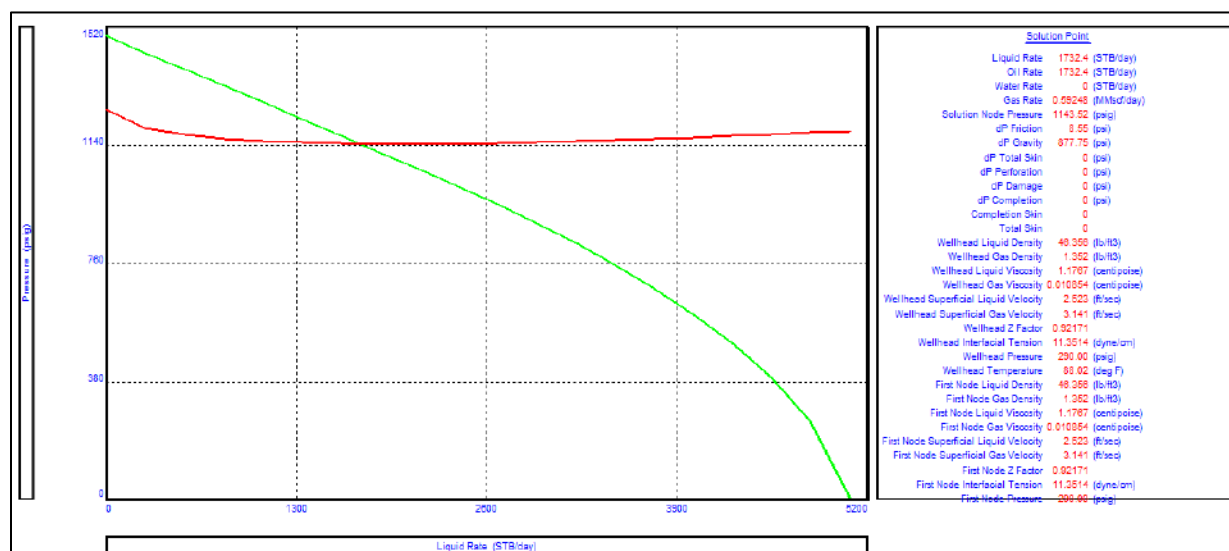


Figure 4.9 API 50

4.2.2. Gas-Liquid Ratio

This section examines how well performance is influenced by different gas-liquid ratios (GLRs), both with and without the use of foam injection, across various water cut scenarios. GLR is a crucial factor in the design of artificial lift systems, as it impacts the pressure gradient, the behavior of multiphase flow, and the overall efficiency of fluid transport. Using detailed simulations with PROSPER, this study assesses the impact of GLR on a mature well, Well K-01, situated in the Kurdistan region. The analysis compares outcomes at GLRs of 300, 400, and 500 SCF/STB to determine the optimal injection rate that enhances production while reducing flow instability. Particular focus is placed on how foam injection modifies the GLR performance range by enhancing flow stability and decreasing pressure losses, especially in environments with high water cuts. The results in the following subsections highlight the essential role of gas optimization in boosting oil recovery from mature fields through foam-lift techniques.

Discussion on GLR Sensitivity for Mature Oil Well (Water Cut = 0%)

The IPR (Inflow Performance Relationship) and VLP (Vertical Lift Performance) graphs for GLR values of 300 and 500 SCF/STB (**Error! Reference source not found.**¹⁰ and **Error! Reference source not found.**¹¹) illustrate the impact of the gas-liquid ratio on the production characteristics of a mature oil well with no water cut. At a GLR of 300, the intersection of the IPR and VLP curves signifies a stable liquid production rate of 1602.3 STB/day, with a gas output of 0.55915 MMSCFD. However, when the GLR rises to 500, the well's performance is notably hindered—no intersection occurs, indicating that the inflow cannot surpass the outflow resistance at this level of gas. High gas rates increase frictional and gravitational pressure losses in the tubing, leading to production failure.

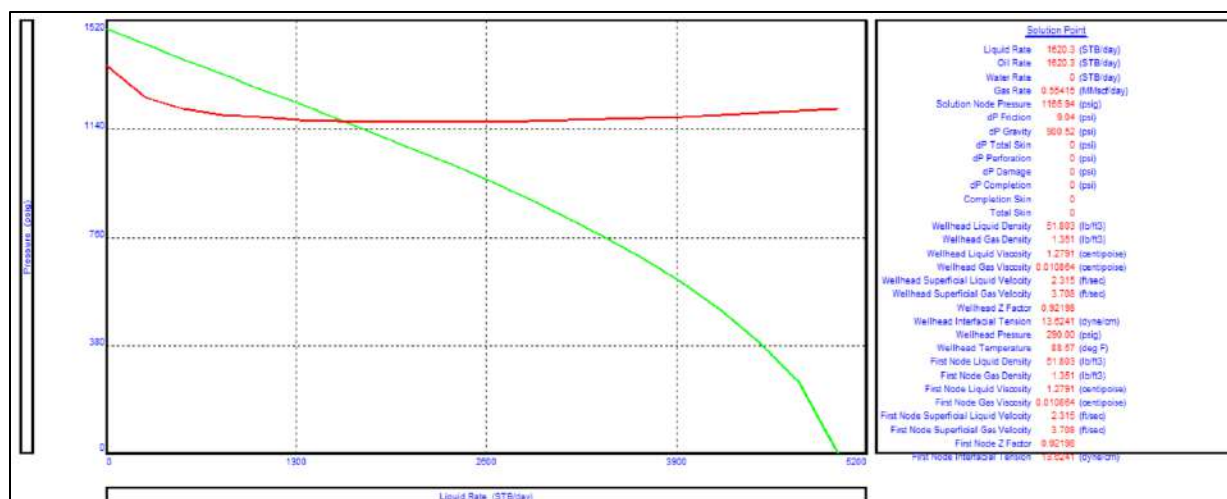


Figure 4.10 IPR and VLP curve at GLR = 300 SCF/STB (Water Cut = 0%)

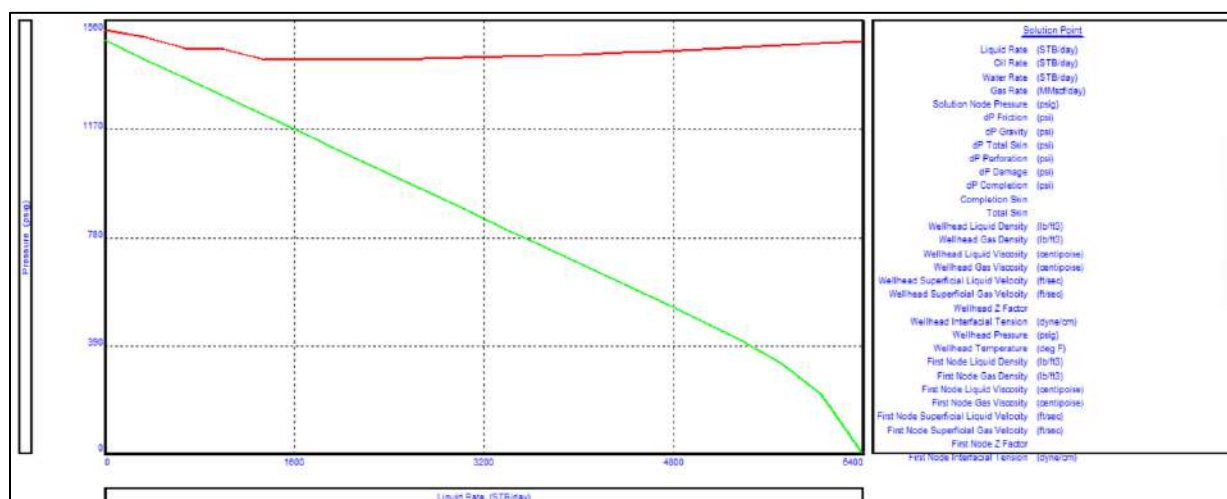


Figure 4-11 IPR and VLP curve at GLR = 500 SCF/STB (Water Cut = 0%)

Sensitivity plots also depict how pressure reacts to changes in gas rates Figure 4.12 in and Figure 4.13. At GLR 300, the pressure profile consistently decreases along the tubing, facilitating fluid lift. Conversely, at GLR 500, the pressure drops levels off and becomes inadequate to maintain flow, confirming the production breakdown seen in the second IPR/VLP plot. The production data in Table 4.3. corroborates this: while GLR 300 and 400 maintain steady oil production around 1600 STB/day, there are no values for GLR 500, indicating non-productive conditions. This underscores the necessity to optimize gas injection rates to avoid surpassing the optimal GLR and risking flow failure.

Table 4.3: Well Production Parameters at Various GLRs (Water Cut = 0%)

GOR	WATER CUT	TOP NODE PRESSURE	TOTAL GOR	LIQUID RATIO	OIL RATIO	GAS RATIO
300	0	290	342	1602.3	1602.3	0.55915
400	0	290	342	1580.3	1580.3	0.54048
500	0	290	342	-	-	-

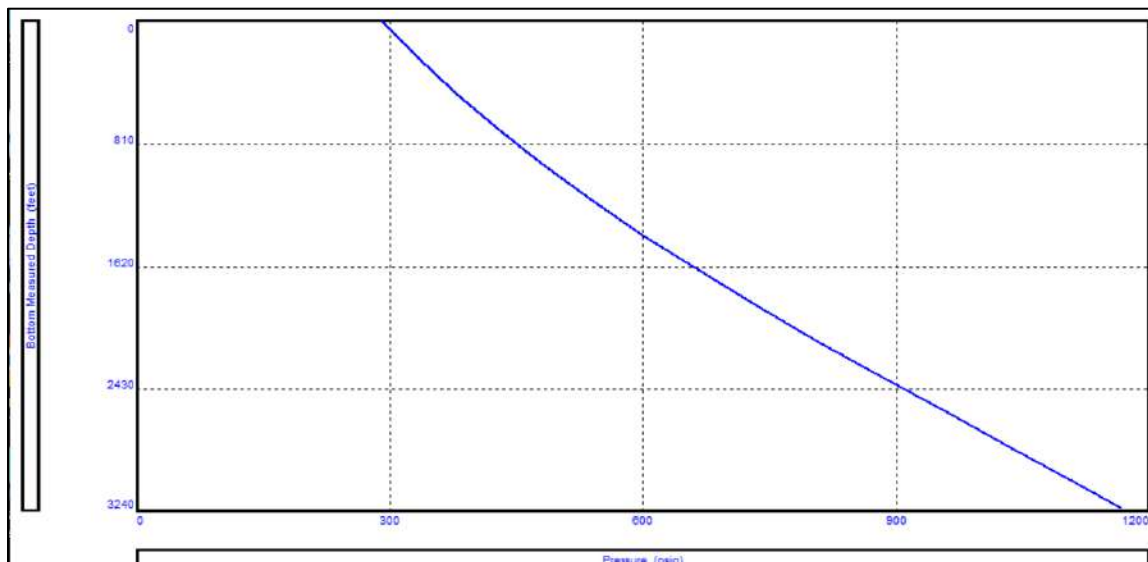


Figure 4.12 Pressure sensitivity curve at GLR = 300 SCF/STB

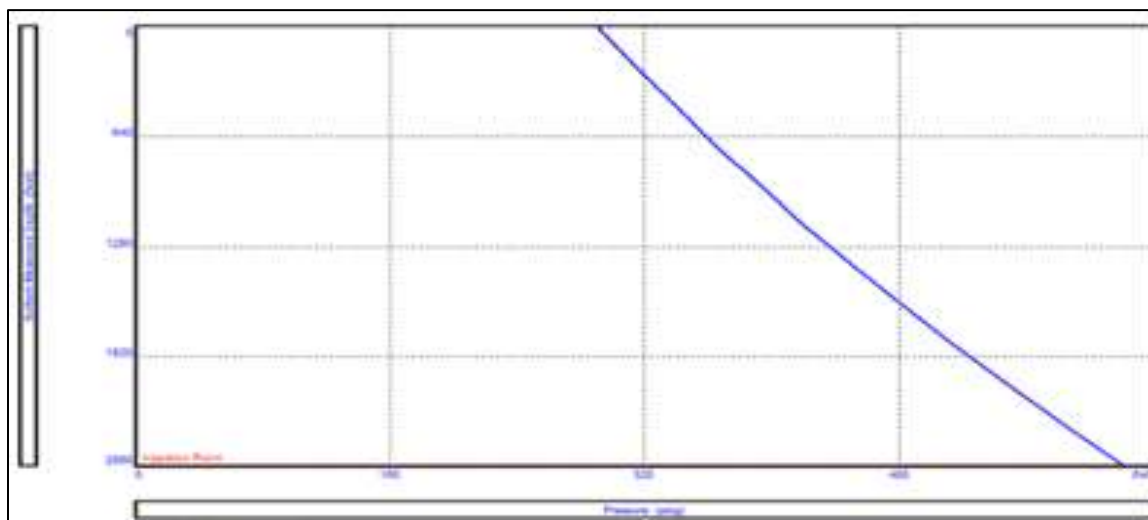


Figure 4.13 Pressure sensitivity curve at GLR = 500 SCF/STB

Discussion on GLR Sensitivity with Foam Injection – Well K-01 (Water Cut = 0%)

Figures 4.14 and 4.15 depict the performance of Well K-01 with foam injection at GLR values of 300 and 500 SCF/STB, respectively, under conditions of 0% water cut. Compared to scenarios without foam, these IPR/VLP plots demonstrate enhanced liquid production and improved intersection behavior due to foam's role in stabilizing the multiphase flow regime. At GLR 300, foam support increases production to 3196.6 STB/day. At GLR 500, although production decreases to 2847.6 STB/day, stable flow is still maintained, unlike in the non-foam scenario. Foam seems to reduce pressure losses and enhance liquid lifting even as the gas rate increases.

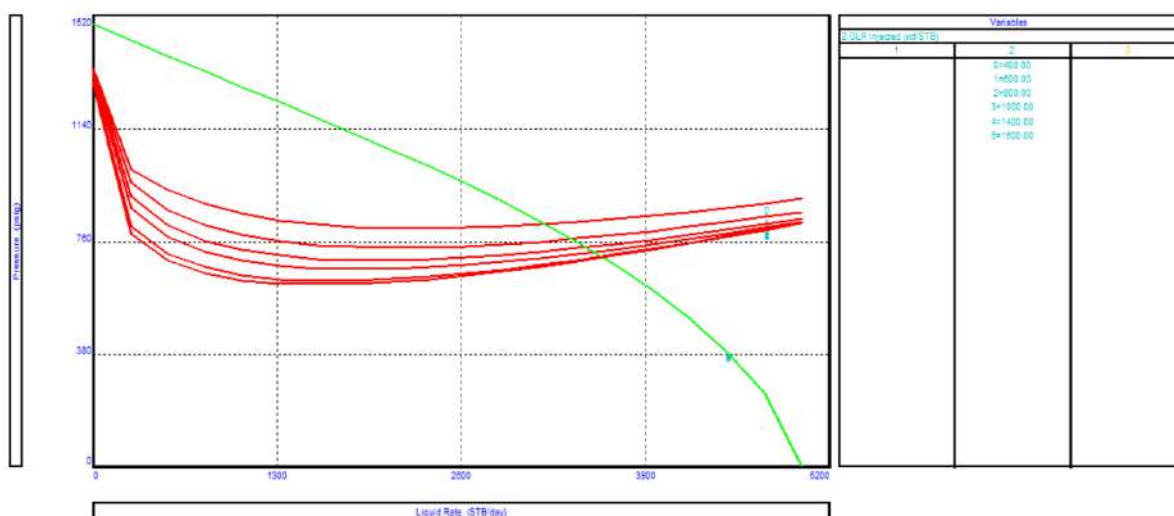


Figure 4.14 IPR and VLP curve at GLR = 300 SCF/STB with Foam – Well K-01

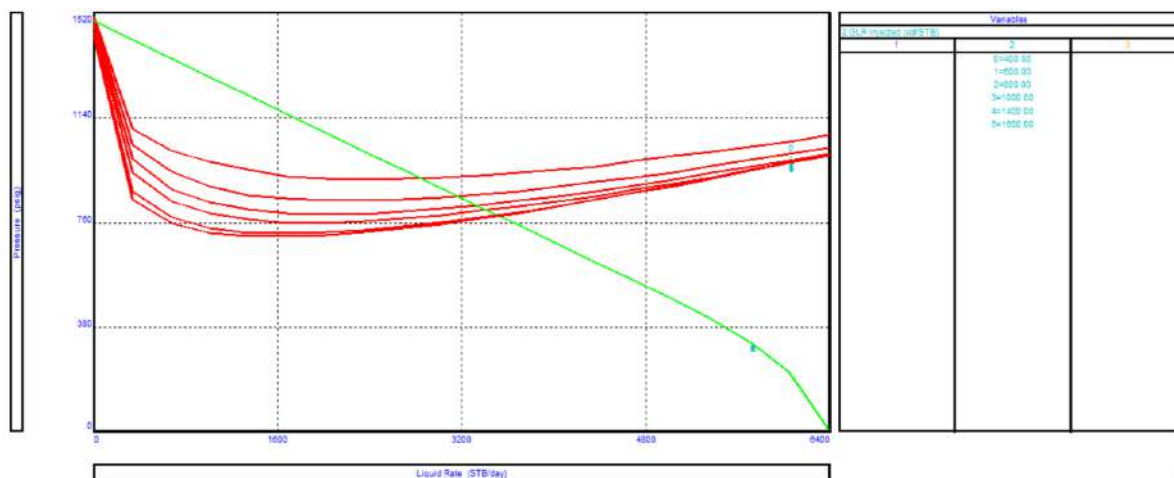


Figure 4.15 IPR and VLP curve at GLR = 500 SCF/STB with Foam – Well K-01

Figures 4.16 and 4.17, showing pressure versus depth sensitivity under foam-lifted conditions, confirm effective pressure gradients across depths at both GLR levels.

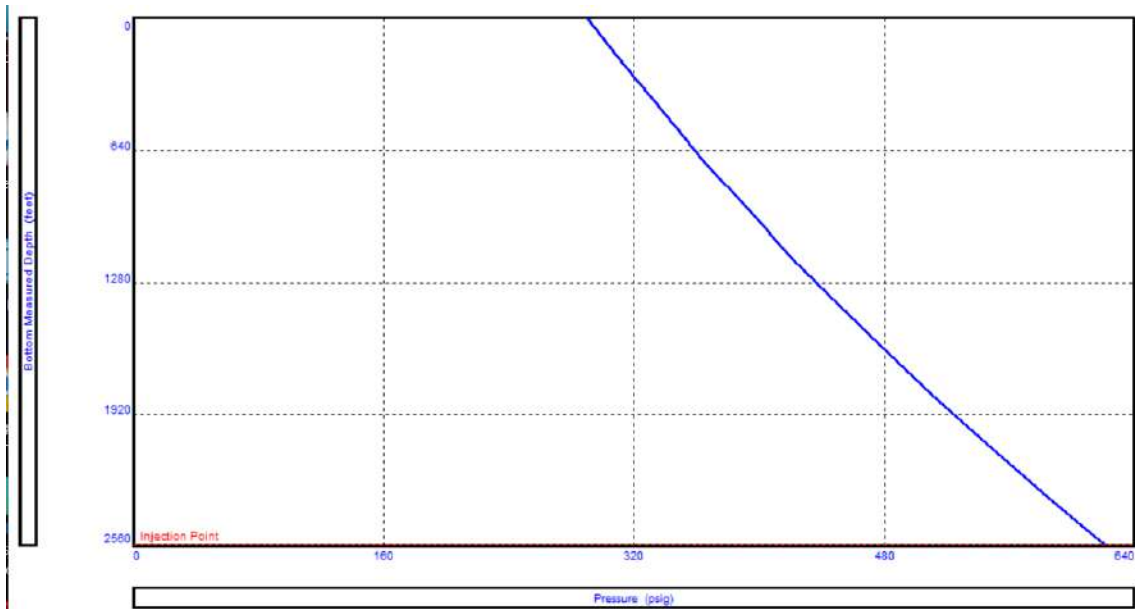


Figure 4.15: Pressure sensitivity curve at GLR = 300 SCF/STB with Foam – Well K-01

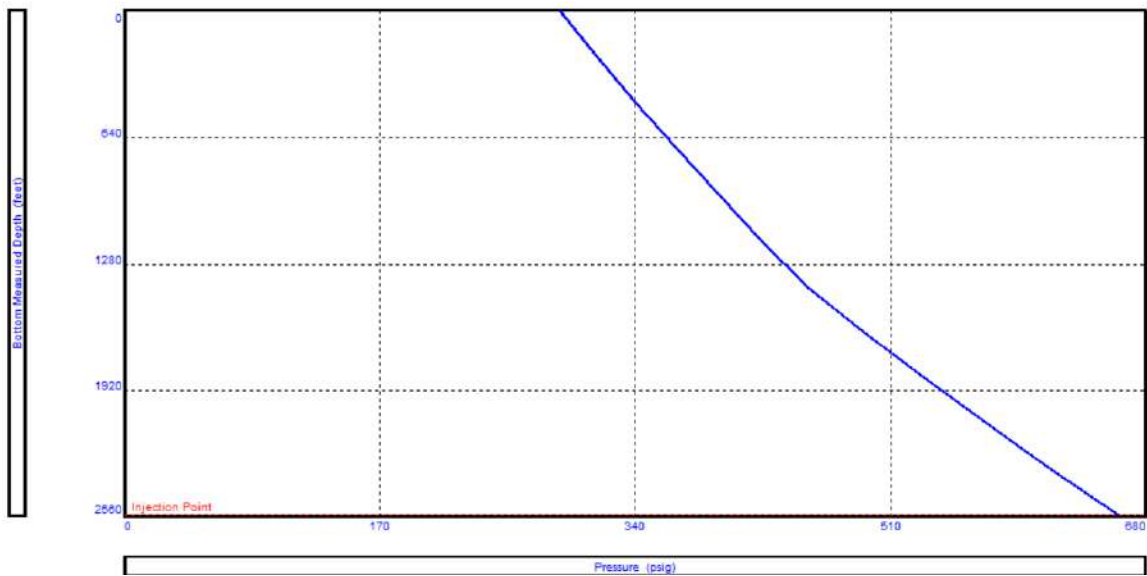


Figure 4.16 Pressure sensitivity curve at GLR = 500 SCF/STB with Foam – Well K-01

Table 4.4 summarizes the production performance across GLRs, with GLR 400 showing the highest flow rate of 3325.6 STB/day, indicating foam lift is most effective at this level. Beyond this point, efficiency slightly declines. The foam-GOR interaction curve Further illustrates the response trend of various GLRs (400 to 1600 SCF/STB), generally showing enhanced flow

potential over the non-foam case. Foam aids in extending the productive range of gas injection while stabilizing flow dynamics.

Table 4.4: Well K-01 Production Parameters at Various GLRs with Foam Injection (Water Cut = 0%)

GOR	WATER CUT	TOP NODE PRESSURE	TOTAL GOR	LIQUID RATIO	OIL RATIO	GAS RATIO
300	0	290	342	3196.6	3196.6	1.093
400	0	290	342	3325.6	3325.6	1.137
500	0	290	342	2847.6	2847.6	0.97389

Discussion on GLR Sensitivity with Foam Injection – Well K-01 (Water Cut = 45%)

Figures 4.17 and 4.18 illustrate the IPR/VLP diagrams for Well K-01 with foam injection at gas-liquid ratios (GLRs) of 300 and 500 SCF/STB, under a condition of 45% water cut. The addition of foam in these scenarios enhances lift efficiency, despite the complexity introduced by the presence of water in the multiphase flow. At a GLR of 300, the liquid production is 2840.9 STB/day, while at a GLR of 500, it slightly decreases to 2574.8 STB/day. Although these rates are lower compared to dry cases, foam injection is beneficial as it maintains stable intersection points between IPR and VLP, indicating reliable flow.

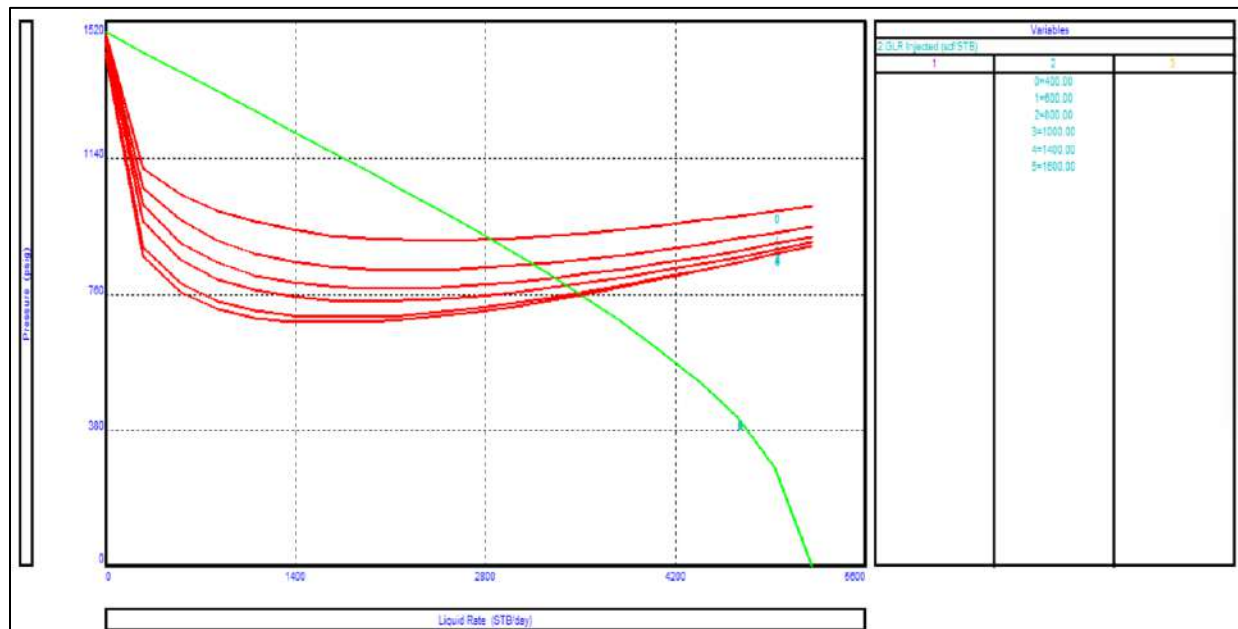


Figure 4.17 IPR and VLP curve at GLR = 300 SCF/STB with Foam – Water Cut 45%

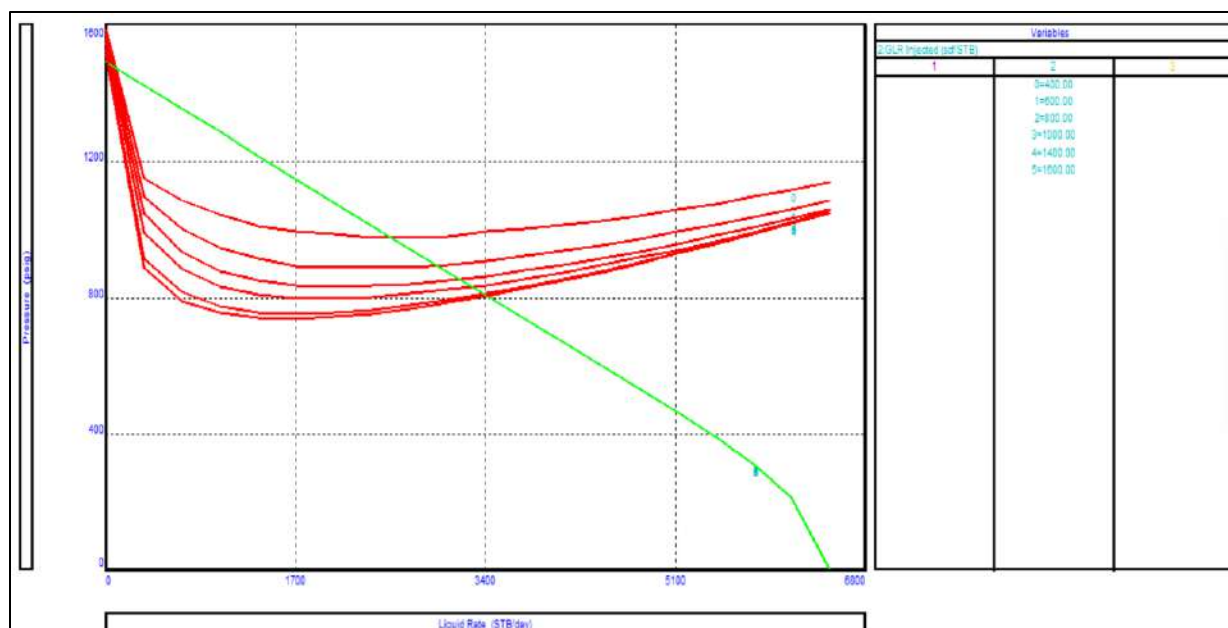


Figure 4.18 IPR and VLP curve at GLR = 500 SCF/STB with Foam – Water Cut 45%

Figures 4-19 and 4.20 demonstrate the pressure-depth sensitivity under the same GLR conditions. Despite the higher water content, the pressure profile continues to decline, which is crucial for lift.

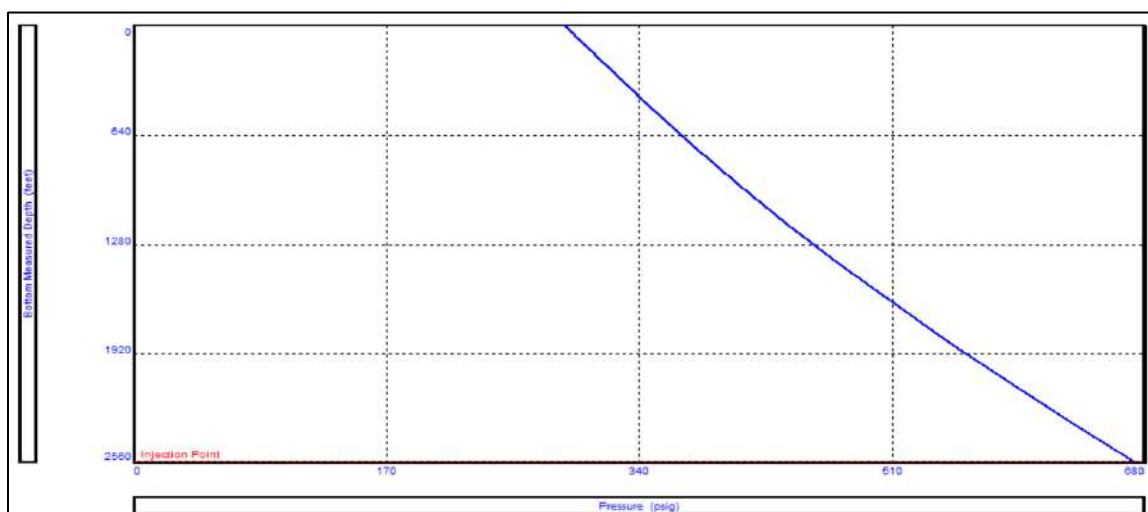


Figure 4.19 Pressure sensitivity curve at GLR = 300 SCF/STB with Foam – Water Cut 45%

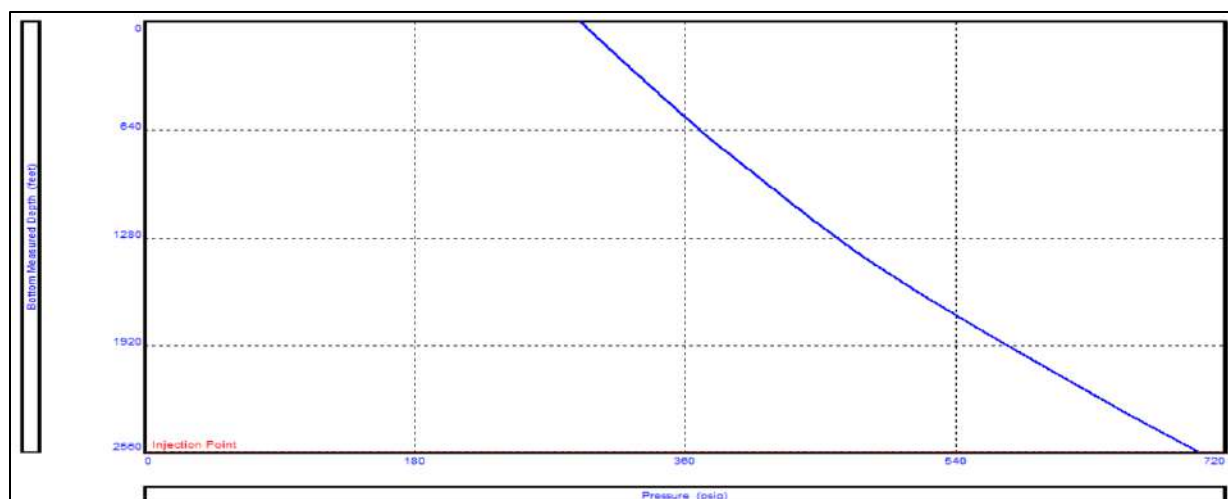


Figure 4.20 Pressure sensitivity curve at GLR = 500 SCF/STB with Foam – Water Cut 45

Table 4.5: Well K-01 Production Parameters at Various GLRs with Foam Injection (Water Cut = 45%)

GOR	WATER CUT	TOP NODE PRESSURE	TOTAL GOR	LIQUID RATIO	OIL RATIO	WATER RATIO	GAS RATIO
300	45	290	342	2840.9	1562.5	1278.4	0.53437
400	45	290	342	2861.0	1573.6	1287.5	0.53816
500	45	290	342	2574.8	1416.1	1158.6	0.48431

To sum up, this chapter presented the impact of foam injection on well performance across various gas-liquid ratios (GLRs) and API gravities, both under dry and wet production conditions. The analysis demonstrated that foam injection consistently enhanced production performance, particularly in wells with initially lower API gravity and at moderate GLRs.

For Well K-01, the optimum performance was observed at GLR 400 with API 45 under dry conditions, where foam injection significantly increased the oil rate. Under wet conditions (45% water cut), production ceased at low API but recovered starting from API 36. Foam effectiveness diminished at low API gravities in the presence of water.

These results confirm that foam injection is most beneficial at moderate-to-high GLR levels and API gravities above 36, particularly in minimizing the negative effect of water cut and improving lift efficiency in mature oil wells.

Chapter 5: Conclusion and Recommendation

5.1 Conclusion

This study comprehensively analyzed the impact of foam injection on well productivity in mature oil fields, emphasizing the interaction of API gravity, gas-liquid ratio (GLR), and water cut. The analysis was conducted on a distinct well from the Kurdistan region, using PROSPER software for IPR and VLP simulations under varying conditions with and without foam. The outcomes reveal actionable insights into optimizing gas-lift systems using foam-assisted recovery techniques.

Key conclusions drawn from the analysis include:

- Foam injection considerably enhanced oil production, particularly in low API and high water cut conditions where conventional lift methods underperformed.
- Well K-01 achieved optimum flow conditions at GLR 400 SCF/STB and API 45, producing 3325.6 STB/day with foam support under dry conditions.
- In Well K-01 with 45% water cut, foam sustained flow where dry cases failed, with GLR 400 yielding the best result of 2861 STB/day.
- Foam stabilized pressure gradients and improved intersection behavior in IPR/VLP plots, allowing effective lift even at high gas rates.
- Production rates without foam dropped or ceased entirely at high GLRs, underscoring foam's critical role in multiphase flow stabilization.
- The pressure sensitivity plots revealed that foam minimized pressure drop fluctuations across depth, supporting more stable vertical lift performance.

Moreover, foam injection enabled more efficient gas utilization, reducing the likelihood of gas over-injection and the related energy losses. Its ability to extend the productive GLR range was particularly valuable in field scenarios where reservoir pressure is already depleted.

This research demonstrates that customized foam selection and careful control of GLR can significantly optimize artificial lift strategies in mature wells. It also highlights the importance of aligning foam type with reservoir conditions—salinity, temperature, and fluid composition—to achieve sustainable production outcomes.

In conclusion, foam-lift systems are proven to be technically effective, environmentally beneficial, and operationally flexible. The methodology and findings from this project provide a solid

foundation for future implementation in similar mature fields, while also suggesting directions for continued research and field-scale validation.

5.2 Recommendation

To achieve efficient production while reducing environmental impact, it is advisable to use biodegradable foaming agents in foam lift operations for well K-01 particularly when dealing with high water-cut scenarios. This well is situated in the Kurdistan region of Iraq, where both high operational efficiency and environmental stewardship are essential. Conventional synthetic foams present environmental hazards due to their persistence in soil and water. In contrast, biodegradable foams break down into non-toxic substances, thereby minimizing the risk of long-term pollution and supporting sustainable oilfield development practices.

Technical Recommendations

- Implement foam injection primarily at GLRs between 400–500 SCF/STB for optimum lifting efficiency.
- Use foam for mature wells with moderate API (36–45) and noticeable water cut (>30%) to sustain flow.

Environmental Recommendations

- Prioritize the use of biodegradable foams such as APGs, MES, and amino acid based surfactants to reduce environmental risks.
- Select materials that offer thermal and salinity tolerance without compromising biodegradability.
- Apply foam lift only when necessary to minimize chemical usage and limit ecological footprint.

Research Recommendations

- Future studies should explore the long-term performance of biodegradable foam in various reservoir conditions.

- Investigate cost-benefit analysis comparing foam lift with other artificial lift systems. Conduct pilot field-scale studies to validate lab and simulation findings on foam injection efficiency in different well environments.
- Study the effect of foam injection in deeper, high-pressure wells or unconventional reservoirs.

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Federal Republic of Iraq
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Experimental Investigation of Using Pomegranate Peel Powder for Combating Lost Circulation Problem

A project submitted to the College of Engineering at Al-Kitab University as a partial fulfilment for the degree of Bachelor of Science in Petroleum Engineering

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بِسْمِ اللَّهِ الرَّحْمَنِ الرَّحِيمِ

أَقْرَأْ بِاسْمِ رَبِّكَ الَّذِي خَلَقَ ﴿١﴾ خَلَقَ الْإِنْسَانَ مِنْ عَلَقٍ ﴿٢﴾ أَلَمْ تَكُنْ مِنْ بَيْنِ يَدَيْهِ أَلْفَ مِائَةٍ سَبْعِينَ مِائَةً وَأَلْفَ أَلْفٍ نَحْوَ ذَلِكَ قَدْ خَلَقَ الْإِنْسَانَ مِنْ عَلَقٍ ﴿٣﴾ أَلَمْ تَكُنْ مِنْ بَيْنِ يَدَيْهِ أَلْفَ مِائَةٍ سَبْعِينَ مِائَةً وَأَلْفَ أَلْفٍ نَحْوَ ذَلِكَ قَدْ خَلَقَ الْإِنْسَانَ مِنْ عَلَقٍ ﴿٤﴾ أَلَمْ تَكُنْ مِنْ بَيْنِ يَدَيْهِ أَلْفَ مِائَةٍ سَبْعِينَ مِائَةً وَأَلْفَ أَلْفٍ نَحْوَ ذَلِكَ قَدْ خَلَقَ الْإِنْسَانَ مِنْ عَلَقٍ ﴿٥﴾

أَلَمْ تَكُنْ مِنْ بَيْنِ يَدَيْهِ أَلْفَ مِائَةٍ سَبْعِينَ مِائَةً وَأَلْفَ أَلْفٍ نَحْوَ ذَلِكَ قَدْ خَلَقَ الْإِنْسَانَ مِنْ عَلَقٍ ﴿٦﴾ أَلَمْ تَكُنْ مِنْ بَيْنِ يَدَيْهِ أَلْفَ مِائَةٍ سَبْعِينَ مِائَةً وَأَلْفَ أَلْفٍ نَحْوَ ذَلِكَ قَدْ خَلَقَ الْإِنْسَانَ مِنْ عَلَقٍ ﴿٧﴾ أَلَمْ تَكُنْ مِنْ بَيْنِ يَدَيْهِ أَلْفَ مِائَةٍ سَبْعِينَ مِائَةً وَأَلْفَ أَلْفٍ نَحْوَ ذَلِكَ قَدْ خَلَقَ الْإِنْسَانَ مِنْ عَلَقٍ ﴿٨﴾ أَلَمْ تَكُنْ مِنْ بَيْنِ يَدَيْهِ أَلْفَ مِائَةٍ سَبْعِينَ مِائَةً وَأَلْفَ أَلْفٍ نَحْوَ ذَلِكَ قَدْ خَلَقَ الْإِنْسَانَ مِنْ عَلَقٍ ﴿٩﴾ أَلَمْ تَكُنْ مِنْ بَيْنِ يَدَيْهِ أَلْفَ مِائَةٍ سَبْعِينَ مِائَةً وَأَلْفَ أَلْفٍ نَحْوَ ذَلِكَ قَدْ خَلَقَ الْإِنْسَانَ مِنْ عَلَقٍ ﴿١٠﴾

[سورة العلق , ١-٥]

Abstract

In the oil and gas industry, a significant issue is lost circulation, which occurs when unwanted loss of drilling mud takes place during drilling operations. Lost circulation can harm expensive mud, lead to delays in drilling, and ultimately increase the cost of drilling and a solution to lost circulation is to add lost circulation material (LCM) to the mud. LCMs can be utilized in the form of fibrous materials, flake materials, or granular materials. However most traditional LCMs have limitations which include not being able to properly seal large fractures, mechanical integrity issues under HPHT conditions, and possibly damaging a production zone because they are often not soluble.

The current experiments focused on the potential of Pomegranate Peel (PP) as a natural and more environmentally-friendly LCM. Base experiments were performed to assess PP properties in comparison to conventional CaCO_3 LCM and a reference mud with no LCMs. Testing included: densities, pH, rheological properties, solubility, and corrosivity testing. Pomegranate peels were tested in three sizes (fine, medium, and coarse) at several concentrations using an HPHT filter press (500 psi, 50 °C.).

The results indicated that 15 ppb fine PP performed better than the 20-ppb fine CaCO_3 in controlling filtration and improving mud properties. PP mud had: 8.5 ppg density, pH 9.5, plastic viscosity = 13.5 cP, yield point = 24 lb/100 ft², gel strengths were 17/35 lb/100 ft², the solution endured 96% solubility in 15% HCl, 81% filtrate reduction, and mud cake thickness was 2 mm. The CaCO_3 mud had: 8.95 ppg density, pH 11.8, viscosity 15.7 cP, gel strengths of 21/52 lb/100 ft², 47% filtrate reduction, and a mud cake thickness of 4.5mm.

All in all, PP provides a natural LCM that is environmentally and economically favorable as well as provides a more safe and sustainable drilling operation.

Dedication

To our beloved parents, whose unwavering love, support, and sacrifices have been the foundation of our journey. To our dear brothers and sisters, whose camaraderie and inspiration have been a constant source of strength and motivation. This project is dedicated to you all, with boundless gratitude and love.

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Lastly, but by no means least, we wish to acknowledge our family for their unwavering support and boundless patience during the challenging phases of this project. Their love and encouragement have been our rock throughout this journey.

Ghaid AlShmari, Jaiba Omer and Varin Farhad

Supervisor's Approval

Hereby, I state that this project as entitled (Experimental Investigation of Utilizing Pomegranate Peel Powder for Combating Lost Circulation) was prepared under my supervision at the department of Petroleum Engineering, the College of Engineering at Al-Kitab University by (Ghaid Falah Dawi, Taiba Omer Motaab and Varin Farhad Mahmood) as a partial fulfillment for the degree of Bachelor of Science (B.Sc.) in Petroleum Engineering.

I have read and reviewed this work and I confirm that it is an original work to the best of our knowledge.

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Abbreviations and Nomenclatures

AlAc	Aluminum Acetate
API	American Petroleum Institute
ASWA	Acid Soluble Weighting Additive
BHST	Botton Hole Static Temperature
C	Coarse Sized
CaCO ₃	Calcium Carbonate
CACP	Chemically Activated Cross-Linked Pills
CMC	Sodium Carboxymethyl Cellulose
cP	Centipoise
DDM	Diamino Diphenyl Methane
DVC	Deformable-Viscous-Cohesive
ECD	Equivalent Circulating Density
ECP	Eichhornia Crassipes Plant
ETs	Ellagitannins
EUC	Eucalyptus Camaldulensis
F	Fine Sized
FIT	Formation Integrity Test
FSM	Fracture Sealing Material
GM	Ground Marble
HCl	Hydrogen Chloride
HGBs	Hollow Glass Beads
HPAM	Hydrolyzed Polyacrylamide
HPHT	High Pressure High Temperature
HSE	Health Safety and Environment
HSLCM	High Strength Lost Control Material
LCM	Lost Circulation Material

LOT	Leak Off Test
M	Medium Sized
MgO	Methylglyoxal
MOS	Magnesium Oxy sulfate
MPD	Managed Pressure Drilling
NaOH	Sodium Hydroxide
OBM	Oil Based Mud
PAC	Polyanionic Cellulose
PEI	Polyethyleneimine
pH	Potential of Hydrogen
PP	Pomegranate Peel
PPA	Permeability Plugging Apparatus
ppb	Pounds Per Barrel
ppg	Pounds Per Gallon
PPT	Permeability Plugging Tester
PV	Plastic Viscosity
RGC	Resilient Graphite Carbon
RM	Reference Mud
ROP	Rate of Penetration
RPM	Revolution Per Minute
RSC	Resilient Size Carbon
RSF	Rapid Setting Fluid
SBM	Synthetic-Based Mud
SCC	Sized Calcium Carbonate
SMEPs	Shape Memory Epoxy Polymers
UBD	Underbalanced Drilling
WBM	Water Based Mud
YP	Yield Point

1 INTRODUCTION

1.1 Preface

Lost circulation is defined as the loss of drilling fluid into the adjacent formations while performing drilling operations. This loss contributes to a reduction in stability and efficiency of the wellbore. (Alkinani, 2017). Lost circulation occurs when the hydrostatic pressure of the fluid inside the wellbore exceeds the pressure of the formation allowing mud to enter into porous or fractured formations and can be intensified by high mud weights, pressure spikes, and weak formations with caverns. Furthermore, lost circulation is one of the largest contributors to non-productive time (NPT) and cost overruns (Savari et al., 2014). Lost circulation has the potential to affect nearly every drilled well across the globe.

Lost circulation severity can be classified as seepage (1–10 bbls/hr), partial (10–500 bbls/hr), and severe (>500 bbls/hr). In addition to the loss of fluid, drilling fluid can cause the pipe to stick in the bore hole and create a state of wellbore instability, making lost circulation an important issue for mitigation from a drilling operations standpoint. The rise of global oil exploration has also driven drilling to deeper depths and into more complicated reservoirs (Jain et al., 2013), which has increased both the cost and risk associated with lost circulation. Lost circulation is estimated to account for \$2–\$4 billion per year, while costs associated with wellbore instability alone account for roughly \$8 billion annually (Mansour et al., 2019).

Industry data suggest more than 1.8 million barrels of mud and treatment resources represent losses of over 1 billion dollars annually (Alsaba et al, 2014). Consequently, lost circulation may amount to as much as 20–40% of total drilling expenditure (Lecolier et al., 2005), indicating that lost circulation has economic ramifications. Consequently, several types of engineered products have been developed to manage or mitigate lost circulation including settable plugs, high-yield stress fluids, and Lost Circulation Materials (LCMs). The most developed technology to address lost circulation is the LCM, which occurs in fibrous, flaky, or granular formats for sealing up fractures and permeable zones (Alkinani, 2017). Despite their popularity, it is noted that one single type of LCM can seal and/or mitigate the lost circulation issue across all well conditions (Feng and Gray, 2018).

In part, the success of an LCM is highly dependent on its ability to form an effective bridge of particles across the fractures (Cook et al., 2012). On the contrary, many traditional conventional materials are notably incapable of sealing larger fractures, poor performance

in HPHT conditions, or damage to productive zones due to limited solubility ([Mansour et al., 2019](#)).

With increased awareness related to the environment, the oil and gas industry is focusing on non-toxic LCMs that are made from biodegradable and natural materials ([Ismail et al., 2021](#)). Regulators are also encouraging such 'green' additives to be incorporated into drilling fluids ([Ramasamy and Amanullah, 2017](#)). Several studies explored the use of agricultural wastes, including waste from agro-products, such rice husk, coconut shells, cocoa bean shells, date seed powder, and sugarcane ash, to enhance the properties of drilling mud therefore minimizing fluid loss ([Purnomosidi et al., 2021](#)).

The present study investigated the opportunities of utilizing Pomegranate Peel (PP) that is biodegradable and cost-effective as a new LCM. Laboratory experiments were conducted under HPHT conditions and the PP's performance was evaluated as a function of the size of the PP particles and concentration. The density, viscosity, yield point, gel strength, and pH were assessed to confirm performance. The results indicate that PP can effectively mitigate losses while maintaining similar or improved mud properties.

In summary, the study presents the PP a new, natural, and environmentally friendly LCM capable of mitigating the lost circulation issue, reducing operational costs, and contributing to more sustainable drilling practices.

1.2 Problem Statement

Drilling fluid, also referred to as mud, is a critical component in operations involving wells because it cools down and lubricates the drill bit, removes cuttings, stabilizes the wellbore, and minimizes the entrance of formation fluids into the well ([ASME, 2005](#)). One of the biggest challenges faced in drilling activities is the loss of drilling fluid into formations, thereby adding extra costs to operations, particularly with deep or complex wells that have a considerable share of expense in the form of fluid costs. The oil and gas industry reportedly loses approximately \$800 million annually due to fluid losses, which contributes in a major way to non-productive time (NPT).

To combat this issue, Loss Circulation Materials (LCMs) are utilized in efforts to seal fractures and permeable zones ([Chenevert and Sharma, 2009](#)). However, many traditional LCMs do not function well under high-pressure and high temperature (HPHT) conditions.

These LCM materials can be limited in a variety of ways, including low mechanical strength, low thermal stability, and inability to seal larger voids. A further drawback of many commercially available LCMs is they are often also toxic substances that can pose threats to workers and the environment as well as be high cost and add to the expenses ([Chenevert and Sharma, 2009](#)).

In the past few years, researchers have recently begun focusing their attention on natural and ecologically friendly LCMs as a sustainable substitute for synthetic additives, which have included the use of rice husks, coconut shells and date seed powder which have been shown to improve some mud properties and lower fluid loss. These biodegradables, non-toxic, cost-effective plant-based materials are in line with the climate change efforts being made by the oil industry to produce more sustainable drilling practices. With technological advances continuing, a natural LCM or series of LCMs will provide an effective and eco-friendly means of minimizing fluid loss and improving drilling performance ([Hossain and Wajheeuddin, 2016](#)).

1.3 Project Objectives

This research analyzes Pomegranate Peel (PP) as a natural, eco-friendly, and biodegradable material to manage the loss of drilling fluid. It also analyzes the effect of PP on important mud properties, such as viscosity, density, pH, and gel strength. The primary hypothesis is that incorporating the PP material in a drilling fluid will maintain hydraulic pressure to better control fluid loss in comparison to traditional material, specifically calcium carbonate (CaCO_3). It is not expected that the addition of PP will adversely influence rheological properties, including drilling productivity.

To prove this, a number of Pomegranate Peel (PP) formulations were developed and tested in water-based mud systems. Due to its high surface energy, PP will therefore interact with other mud additives and ultimately help create a sealing barrier to manage fluid loss. The objective is to utilize this natural local material in a drilling fluid while maintaining the overall characteristics of the fluid itself.

The main objectives of this study are:

- To prepare and characterize a Pomegranate Peel material.
- To evaluate its effectiveness through the API high temperature high pressure (HTHP) filtration tests.

- To evaluate the effect of Pomegranate Peel on density, viscosity, pH, and gel strength of a drilling fluid.
- To determine if by adding Pomegranate Peel, there is reduced need for additional LCM additives, or reduce amount of costs of drilling fluids.

1.4 Scope of The Work

The project is structured into five distinct chapters.

Chapter One - Introduction: This chapter provides a summary of the purpose and significance of the project, a discussion of the implications of Lost Circulation Materials (LCMs) for drilling fluids, and an overview of the complications of drilling operations. The chapter contains the introduction of a novel natural product, Pomegranate Peel (PP), as an additive to help mitigate fluid loss in the drilling process.

Chapter Two - Theoretical Background: This chapter explains lost circulation, the causes of lost circulation, methods of prevention and treatment of lost circulation, and a literature review of commercial and natural LCMs for drilling. Previous studies on various LCMs, along with their benefits and drawbacks, are presented.

Chapter Three - Experimental Work: This chapter describes the methods used to prepare and test PP as a LCM, including description of the methods and instruments utilized to assess drilling fluid properties and performance.

Chapter Four - Results and Discussion: This chapter presents the experimental results, analyzes the results, and compares the PP added fluids to that of standard drilling muds. Critical parameters related to HTHP fluid loss, density, viscosity, and pH to evaluate PP experimental performance in the drilling fluid tests are included.

Chapter Five - Conclusions and Recommendations: This chapter summarizes the major findings of the research, identifies its contributions to the area, and includes recommendations for future work to develop additional natural materials in drilling fluids.

2 THEORETICAL BACKGROUND

2.1 Introduction to Lost Circulation

When drilling fluid moves into geological formations, rather than returning to the annulus and surface, this is called lost circulation. The oil industry loses over a billion dollars per year in rig time, materials, and other costs due to this problem. Lost circulation occurs most frequently in highly permeable zones, depleted reservoirs, and cavernous formations, when mud losses may affect the travel from the shallow, unconsolidated layers to deeper, fractured formations from hydrostatic pressure (Alkinani, 2017). Figure 2.1 identifies the primary formation types associated with lost circulation.

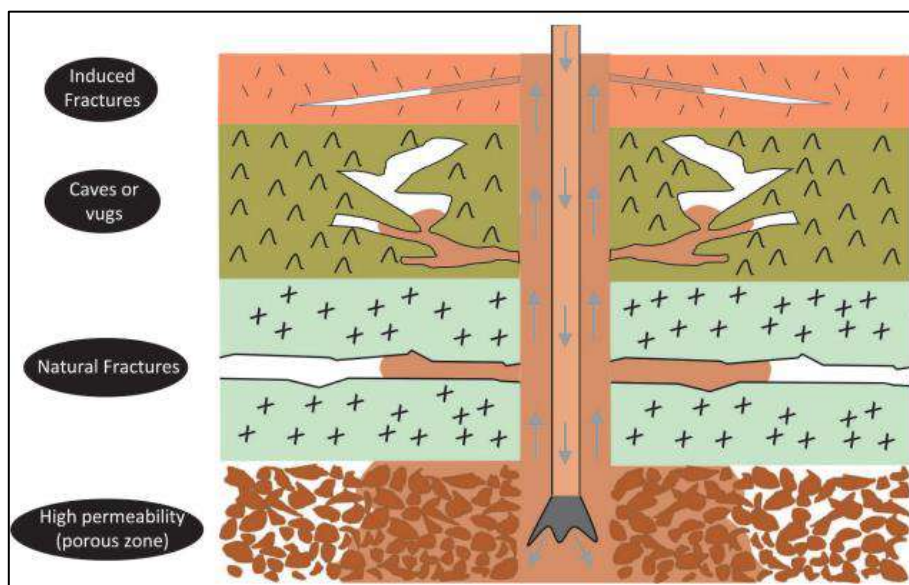


Figure 2.1 Rock formation types causing lost circulation (Mostafavi Toroqi, 2012)

Several methods have been designed to control lost circulation and generally categorized as either preventive (before loss) or corrective (after loss). The most widely used preventive method is to add Loss Circulation Materials (LCMs) to the drilling mud, with the intent to seal fractures in the formation. Service companies continue to develop new LCMs every year, most commonly grouped as fibrous, flaky, or granular based on their material properties. More recently, natural and biodegradable materials have been proposed for their cost-effective and environmentally beneficial solutions for controlling fluid loss.

2.2 Causes of Lost Circulation

Lost circulation, or lost returns, refers to the loss of circulating fluid from the wellbore to the formation in total, or partially (Mostafavi Toroqi, 2012). There are two necessary conditions for the fluid loss to occur:

- 1) the wellbore pressure is greater than the formation pore pressure and,
- 2) a flow path is present (Alkinani, 2017).

Figure 2.2 shows loss of fluid into fractures. The loss could be only a few barrels an hour, or hundreds of barrels within minutes (Kumar et al., 2010). Uncontrolled loss circulation can be expensive and may put the rig and personnel safety at risk with the potential for total well failure.

Loss could be either natural or induced. Natural fractures usually form when rock stress exceeds its strength resulting in planar discontinuities. Fluid loss from porosity is a gradual process; whereas loss into cracks is generally very rapid and then it also decreases over time (Majidi et al., 2010). Larger fractures allow much larger volumes of mud to exit the wellbore, which has a negative impact on drilling performance (Kumar and Savari, 2011). Lost circulation zones may be able to be recognized based on the rate of the mud loss and the impact on performance (Datwani, 2012). Overall, lost circulation can result from natural fractures, induced fractures, or from excessive overbalance pressure.

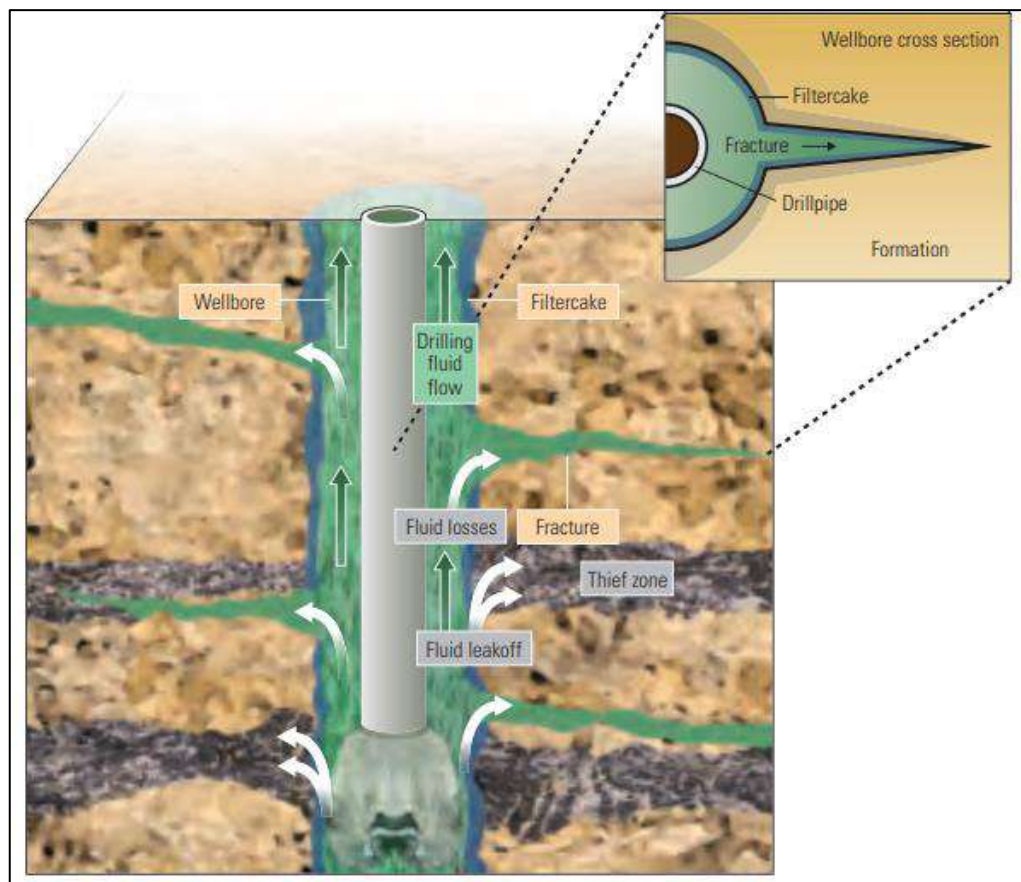


Figure 2.2 Fluid flowing into fractures (Cook et al., 2012)

2.2.1 Natural Losses

Natural losses occur in rocks containing porosity and permeability or with natural fractures. Three types of formations can be recognized:

1. Unconsolidated Formations

Lost circulation is a routine of occurrence in unconsolidated formations which consists of poorly cemented, loose, sands, gravels, clays, or mixtures of these materials (Figure 2.3). The porous structure and relatively high permeability characteristics of a poorly cemented, loose formation allows a drilling mud to flow into the formation rather than returning to the surface through the annulus. Lost circulation can occur at different intensities, from a slight seepage, to an all-out loss of mud. In the case of complete loss, 'blind drilling' can be carried out if water is available and safety is not compromised while confining the well ([Messenger, 1981](#)).

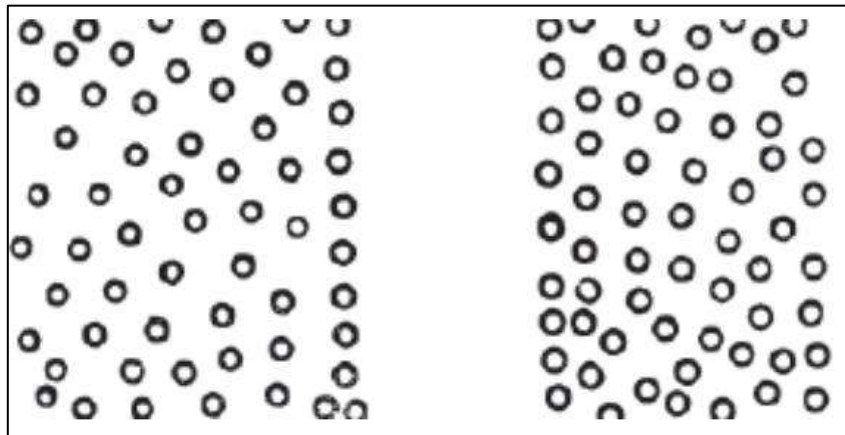


Figure 2.3 Unconsolidated formations ([Datwani, 2012](#))

2. Natural fractures

Natural fractures commonly develop in limestones and chalks from tectonic activity or acid leaching with consequential fluid loss in these formations. Fluid loss can be quite severe - even a 50-psi overbalance pressure can cause lost circulation ([Datwani, 2012](#)). As drilling proceeds, the mud level in the pit decreases and additional fractures may become exposed until a total fluid loss occurs. Figure 2.4 depicts the natural cracks forming with the caveat that overburden must be self-supporting for the fractures to exist.

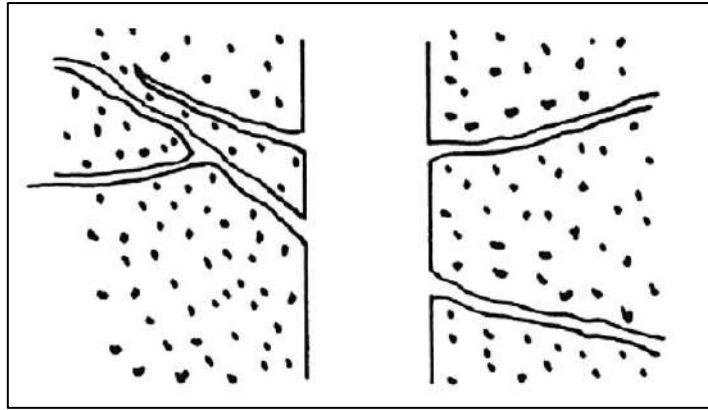


Figure 2.4 Natural fractures (Datwani, 2012)

3. Cavernous and Vugular Formations

Cavernous or vugular features are common within carbonate rocks (limestone and dolomite) at low pressure or volcanic areas. In limestone, vugs form when water is waning through the rock and dissolving part of it (leaching), so that there are holes or voids that may or may not fill with hydrocarbons. When a drill hole encounters a cavity, the drill can drop from inches to feet, causing instant mud loss. Drilling cavity has challenges and drilling is even challenging for mud losses. Figure 2.5 shows how large fractured holes allow fluids to communicate between zones, complicating closure. To drill effectively in vugular formations, it is crucial to have an understanding regarding their vugular features and implement suitable lost circulation mitigation methods.

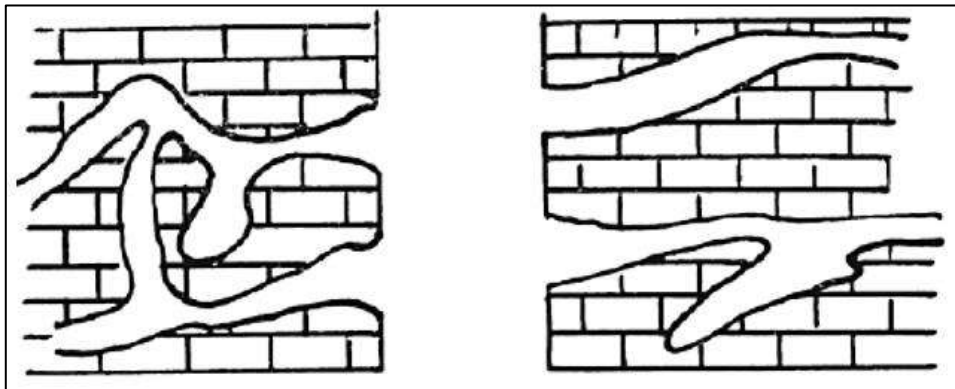


Figure 2.5 Cavernous formations (Datwani, 2012)

4. Depleted Formations

Lost circulation is a common occurrence in depleted reservoirs where sustained production has lowered its pressure. Depleted formations are more susceptible to drilling mud losses for the following reasons:

- a) Formation pressures are lower, allowing the drilling mud to flow into the reservoir and not return to the surface.

- b) The rock is fractured and porous allowing fluids to escape more easily.
- c) The rock matrix is weakened which increases borehole instability and consequently mud losses.
- d) The difference in the pressure between the wellbore and the formation, which makes controlling mud difficult.
- e) Natural faults or fractures, which serve as pathways for fluid loss (Messenger, 1981).

Drilling in depleted formations requires careful planning and real-time observations. It will be critical to evaluate the formation properties and implement proper mitigation measures in a timely manner to ensure drilling performance is achieved in the depleted formations and that borehole integrity is maintained.

2.2.2 Induced Losses

Induced fractures take place when the pressure in the wellbore surpasses the fracture pressure of the rock, resulting in a breakdown of the formation. Once created, these fractures will be difficult to close and may not be able to return to the original strength. If losses occur due to an invert-emulsion fluids, they are extremely difficult to control, compared to water-based muds. Induced fractures account for and create 90% of lost circulation events (Caughron et al., 2002). As a result, pre-planning and prevention are warranted. These losses typically occur due to misplaced intermediate casing or excessive pressures in the wellbore. Some of the more common factors that may contribute to an excessive wellbore pressure are:

1. Excessive Mud Weight
2. Excessive Equivalent Circulation Density, ECD
3. Excessive Pump Rate/Fluid Viscosity
4. Poor Filtration Control
5. Cuttings-Related Losses
6. Pressure Surges
7. Hole Enlargement
8. Circulating Casing
9. Open-Hole Displacements
10. Cementing

2.3 Classification of Lost Circulation

Lost circulation can result in severe economic losses anywhere from millions of dollars to catastrophic events such as blowouts (Alsaba et al., 2014). The severity of lost circulation is typically classified based on the volumetric rate of fluid loss (m^3/hr) (Alkinani, 2017):

- **Seepage loss:** $0.5 - 1 \text{ m}^3/\text{hr}$, possible across any formation.
- **Partial loss:** $1 - 10 \text{ m}^3/\text{hr}$, typically in gravel systems, a small number of natural horizontal fractures, or induced vertical fractures (Alsaba et al., 2014a).
- **Severe loss:** $\geq 15 \text{ m}^3/\text{hr}$, significant fluid escape.
- **Complete loss:** All returns to the surface are lost; typically returns will be lost within long open gravel sections, along large natural fractures, into cavern systems, interconnected vugs, or at extremes within a long-induced fracture (Alsaba et al., 2014).

Alhaidari presented a tabulated classification of drilling fluid losses in his text (Table 2.1). A classification system allows the engineer to use that classification to gauge how to respond to the lost circulation event.

Table 2.1 Loss severity classification (Alhaidari, 2020)

Loss Type	Amount of loss (bbl/hr)
Seepage loss	1 – 10
Partial loss	10 – 500
Sever loss	> 500
Complete loss	No return

2.3.1 Seepage Losses

Seepage losses occur over time and are difficult to identify, particularly with poor fluid-loss control. Although these losses are small, such as those in naturally fractured or very porous formations, it may not be an issue economically if drilling fluid is cheap and rig rates are high. The fluid loss rate is low and does not threaten drilling operations immediately. The most frequent operation used to plug seepage losses is to introduce standard bridging agents that help stabilize wellbore pressure and maintain wellbore integrity (Alkinani, 2017). Nevertheless, seepage losses must be treated with urgency totally if pressure control is a major consideration.

2.3.2 Partial Losses

Partial losses are a more severe level of lost circulation than seepage, occurring when drilling fluid moves into larger networks of fractures or into highly permeable formations. Often, these types of losses will require the addition of Lost Circulation Materials (LCMs) to reduce or stop fluid loss. There may be drilling delays if the mud cannot accomplish its functions, making lost mud and rig stand time a significant cost. In the case of partial losses, fibrous or flake-type LCMs are added to bridge and seal the voids created by lost circulation in the formation ([Alsaba et al., 2014](#)). When mud availability is limited or there are logistical challenges, additional time may be required on the rig for remedial actions.

2.3.3 Severe Losses

Severe lost circulation is when drilling mud is lost quickly and in large quantities. Depending on the severity of the loss of circulation, and rapid decline of hydrostatic pressure, issues can arise resulting in lost circulation problems, stuck pipe, non-productive time in well operations, well control problems, and hole instability. Whenever circulation and hydrostatic pressures drop significantly down in the annulus, mitigation efforts for lost circulation typically require specialized lost circulation materials (LCMs). or dynamic wellbore strengthening measures and/or dynamic wellbore pressure management. Besides LCMs and dynamic pressure management, other remedial measures can include cement plugs, drilling liners, and lost circulation squeezes ([Kumar and Savari, 2011](#)).

2.3.4 Complete Losses

Complete loss of circulation occurs when nothing comes back to the surface and may result in no fluid in the wellbore. In this case, the annulus should be filled with controlled volumes of lighter mud or water or base oil while adjusting the system to maintain an equivalent mud weight. Constant monitoring is crucial to avoid well control issues during this critical time ([Alkinani, 2017](#)).

Each classification of loss circulation can also have sub-classifications based on geological conditions or drilling technique. For example, A fractured formation, with fractures of mixed permeability, is an example of a circumstance for which unique methods may be required. Likewise, preventive measures, such as adding more LCM to the casing, or managed-pressure drilling can be used to reduce loss circulation. [Datwani \(2012\)](#) also categorized lost circulation by volume and time take to (try) to control.

[1] **Minor losses:** 6-470 barrels repaired or controlled in less than (48) hours.

[2] **Major losses:** > 470 barrels repaired or controlled greater than (48) hours.

The identification of the loss type is done by examining observed surface returns, reviewing drilling parameters, and noting wellbore diagnostics, including flow rate, downhole pressure, mud sample, formation evaluation, pressure testing and temperature logging. (Alkinani, 2017).

2.4 Lost Circulation Treatment

Lost circulation is addressed by using lost circulation materials (LCMs) that include wellbore strengthening and pneumatic drilling methods. Whereas wellbore strengthening entails managing fracture propagation, pneumatic fluids (air/gas, aerated fluids or foams) use specialized equipment to operate safely (Nasiri et al. 2018). Of the aforementioned methods, LCMs are the most frequently used approach since they can seal fissures in the formation in order to prevent or treat lost circulation (Saleh et al., 2020).

Conventional LCMs include concrete, granular, fibrous, or flaky solids that can be introduced to the well while drilling or cementing, though (Alsaba et al., 2014). In cases of seepage or partial losses, normal LCMs can be used, or pills can be increased in concentration; however, in cases of damage that causes significant losses, the remedies become more advanced and are seen as “repair” measures, such as, cement, chemically activated or cross-linked pills and “cross-linked” cement, deformable-viscous-cohesive systems, nanocomposite gels, gunk squeezes, and sand slurries (Fidan et al., 2004; Caughron et al., 2002; Mata and Veiga, 2004; Whitfill and Wang, 2005; Lecolier et al., 2005; Collins et al., 2010).

Additives that may also be used when managing lost circulation include:

- Bentonite: increasing mud viscosity to slow fluid flow.
- Polymers: increasing viscosity of fluid but are more costly than bentonite.
- Saw dust, flaked cellophane, and pulverized gypsum: for sealing the loss point.
- Shredded newspaper and cottonseed hulls: as a cheap alternative in sealing.

Often these measures can be combined, and are specified as deformable solids (e.g. ground tires), particulates (e.g. walnut shells), and fibers (e.g. peanut hulls) (Whitfill and Hemphill,

2003). These treatments may be preventative, meaning they occurred prior to the point of loss, or erudite, which will occur after the loss has occurred.

2.4.1 Preventive Methods

Preventative techniques are commonly used in the industry, with increased success compared to corrective measures occurring post-lost circulation (Datwani, 2012). These techniques aim to enhance the wellbore before entering a loss zone (Whitfill, 2008). Wellbore strengthening involves protocols aimed at plugging and sealing induced fractures and ultimately increasing the fracture gradient and expanding the operational envelope. To prevent lost circulation, the engineers develop mud properties, choose the appropriate LCMs, and use specialized drilling techniques (Managed Pressure Drilling (MPD) or Underbalanced Drilling (UBD)). It is crucial to choose the proper additives and concentrations to ensure the mud density does not induce fracture of the formation, which is achieved from determining formation fracture strength with a Leak-Off Test (LOT) or Formation Integrity Test (FIT).

2.4.2 Corrective Methods

After lost circulation has occurred, the corrective treatments are then applied (Kumar and Savari, 2011). These treatments can be added directly to the mud on a continual basis or prepared and applied as pills, depending on the nature of the loss and the formation (Alsaba et al., 2014). Lost circulation materials (LCMs) can serve two primary purposes: to bridge fractures and vugs and to inhibit the propagation of new fractures during drilling (Alkinani, 2017).

As an example, Elkatatny et al. (2020) created a high-strength lost circulation material (HSLCM) for severe losses. The high compressive strength of the HSLCM allows it to act as a plug of isolation and bridge the loss zone while remaining clean and reservoir safe because no crosslinking gellants were added to the mud system. The acid-soluble weighting agent was shown to dissolve >90% in 15 wt.% HCl, thus allowing it to be rapidly removed once it was no longer needed. Unlike a traditional LCM, the HSLCM guaranteed to mitigate considerable circulation losses in the field. Figure 2.6 depicts the mechanisms for managing lost circulation.

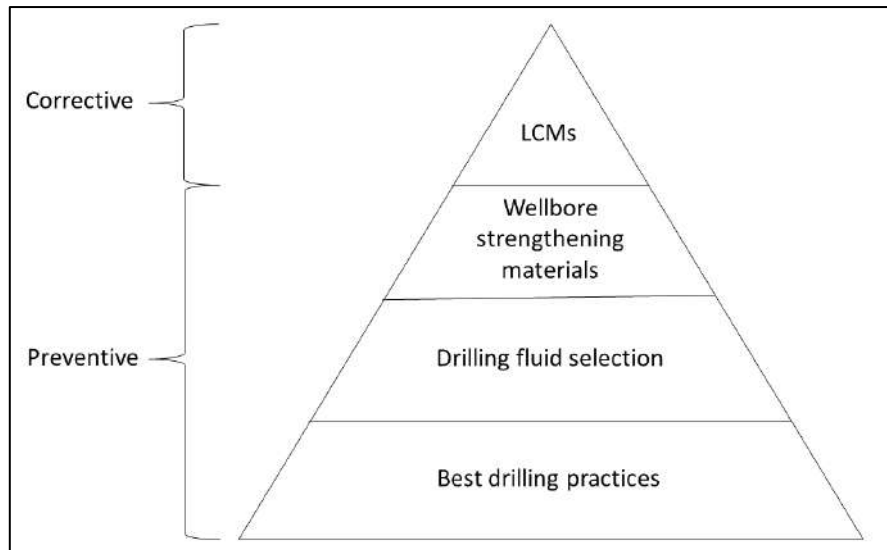


Figure 2.6 Lost circulation management mechanisms

2.5 Lost Circulation Materials

The use of Lost Circulation Materials (LCMs) is common practice to stem or mitigate mud losses. Due to plants of the various types of LCMs and the numerous applications, value should be placed on classifying, testing and evaluating. There is inherent complexity as there is no single LCM that addresses each type of loss due to variations in formations and techniques of losing drilling fluid ([Feng and Gray, 2018](#)), LCMs function on the principle of increasing mud particle size, sufficient to bridge the pore and fractures. LCMs on the basis of structure can be classified as fibrous, flaky, granular and combinations. LCMs must also form a strong enough bridge to withstand the mechanical forces ([Cook et al., 2012](#); [Mansour et al., 2019](#)).

Improvements have been made with LCMs however many LCMs can still be challenged, where LCMs may not seal large fractures (which can also exceed several millimeters) ([Alsaba et al., 2014](#)), LCMs may not function in HPHT environments and in many cases, non-soluble LCMs may also damage production zones, leading to potential reductions of well productivity ([Mansour et al., 2019](#)) and LCM performance is dependent on type of LCM, LCM concentrations' sizes, and fracture width ([Sedaghatzadeh et al., 2021](#)). Higher concentrations are required to allow LCM performance; however, LCM concentrations above critical maximum may have undesired effects. Figure 2.7 provides a classification of the most commonly used LCM types and classification of use, application, formations, and impact of risk.

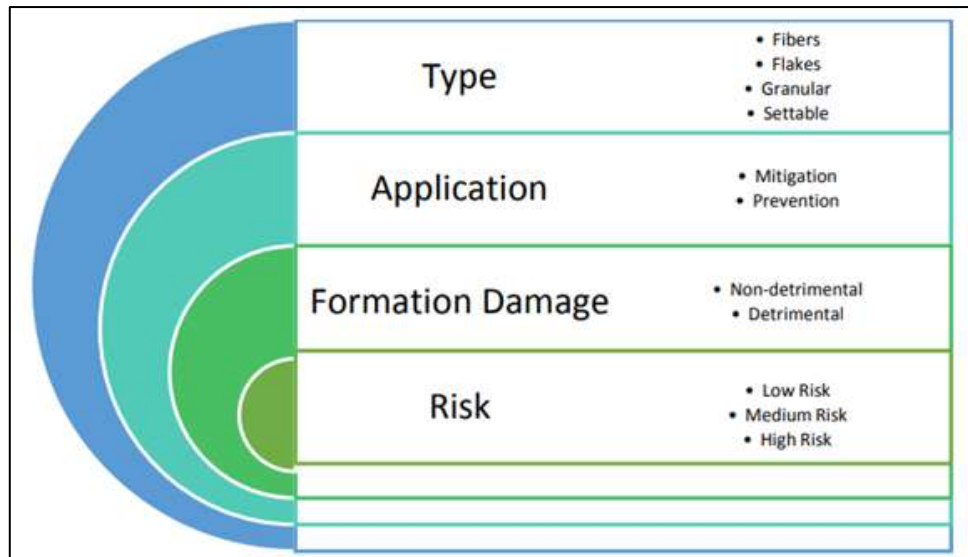


Figure 2.7 Summary of classification of LCMs (Amer et al., 2019)

2.5.1 Granular

Granular Lost Circulation Materials (LCMs) generally utilize two kinds of bridging materials: one that stays at-or-near the entry of the formation and one that can invade and penetrate the formation matrix (Nasiri et al., 2018). The characteristics that affect effectiveness are particle size and shape, as both can help to bridge fractures or seal off pores. Granular LCMs are popular for use in wellbore strengthening because they possess high rigidity and are much more crush resistant than standard LCMs (Savari et al., 2012). A broad particle size distribution is necessary, where a large particle bridges the fracture and small particles fill in the voids resulting in a better seal formed (Alhaidari 2020; (Figure 2.8).

Evidence suggests that particle size and concentration are important factors. Loeppke et al. (1990) showed that calcium carbonate particles larger than the fracture width will form a stable bridge. Similar observations have been made with materials such as gilsonite, nut pods, and perlite. Wang et al. (2015) illustrated that not only does the particle size but also the concentration directly influences the plugging-feature but the bridging performance. Howard and Scott (1951) strongly suggested the importance of LCM concentration, while looking at the formation of seals and the effectiveness of sealing minor fractures.

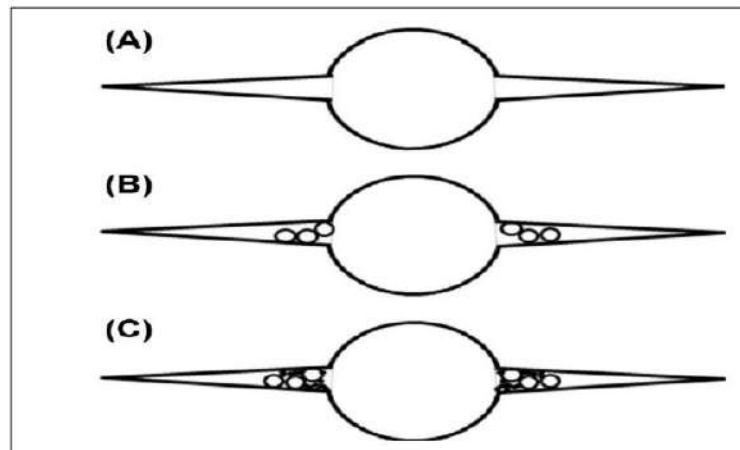


Figure 2.8 The mechanism of bridging and sealing of large and small granular LCMs (Lavrov, 2016)

2.5.2 Flaky

Flaky lost circulation materials (LCMs) make up another category of LCM, and they cover cracks or highly permeable voids in the formation (Nasiri et al., 2018). Their particles have a very large, flat, thin shape and low stiffness, allowing them to mat together over the formation surface. Although they can provide excellent coverage of the void, their low strength and rigidity under pressure limit their effectiveness, and they are often a treatment of last resort (Feng and Gray, 2018). A sized grade of mica, a commonly used flaky LCM, is shown in Figure 2.9.



Figure 2.9 Mica flaky material (Alsaba et al. 2014)

2.5.3 Fibrous

Fibrous LCMs are thin, elongated organic materials that exhibit a specific distribution of particle size (Feng and Gray, 2018; Figure 2.10) and are especially effective for use in porous formations by forming a mat-like bridge across voids and fractures, enabling colloidal mud particles to settle and form a sticky blanket on the surface of the porous formation (Nasiri et al., 2018). This blanket works to seal vugular and fractured zones in an efficient manner (Feng and Gray, 2018). Traditionally, fibrous LCMs are used to control lost

circulation in formations that exhibit high permeabilities. For example, [McKinley and Applegath \(1985\)](#) utilized fibrous LCM pills which contained fibers and polymeric absorbers that expanded on contact with drilling fluid to control losses.



Figure 2.10 A typical fibrous material ([Amer et al. 2019](#))

2.5.4 Blend of Fibrous, Flaky and/or Granular

Combined LCMs, including fibrous, flaky, and granular materials were effective in addressing the considerable fluid losses while drilling ([Alsaba et al. 2014](#); Figure 2.11). The particle size distribution of the material and its combinations are aspects that have been shown to affect their performance. For example, [Whitfill and Hemphill \(2003\)](#) examined the combinations of granular, fibrous, and flaky LCMs on sealing efficiency. [Whitfill and Hemphill \(2003\)](#) designed a mixture of composite LCMs which included a blend of carbon and synthetic polymer with LCMs through mixtures of graphite carbon with scaled calcium carbonate to reduce losses while circulating an oil-based mud.

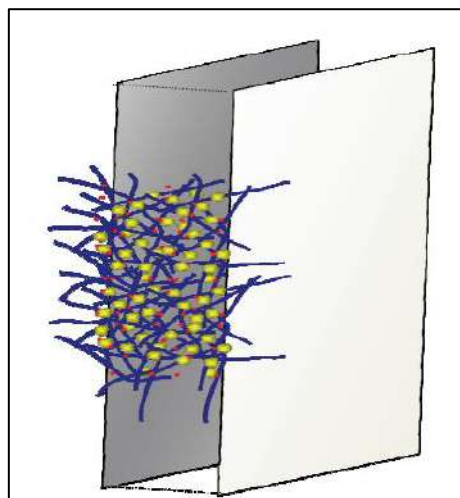


Figure 2.11 An LCM blend of fibers and granules ([Kefi et al., 2010](#))

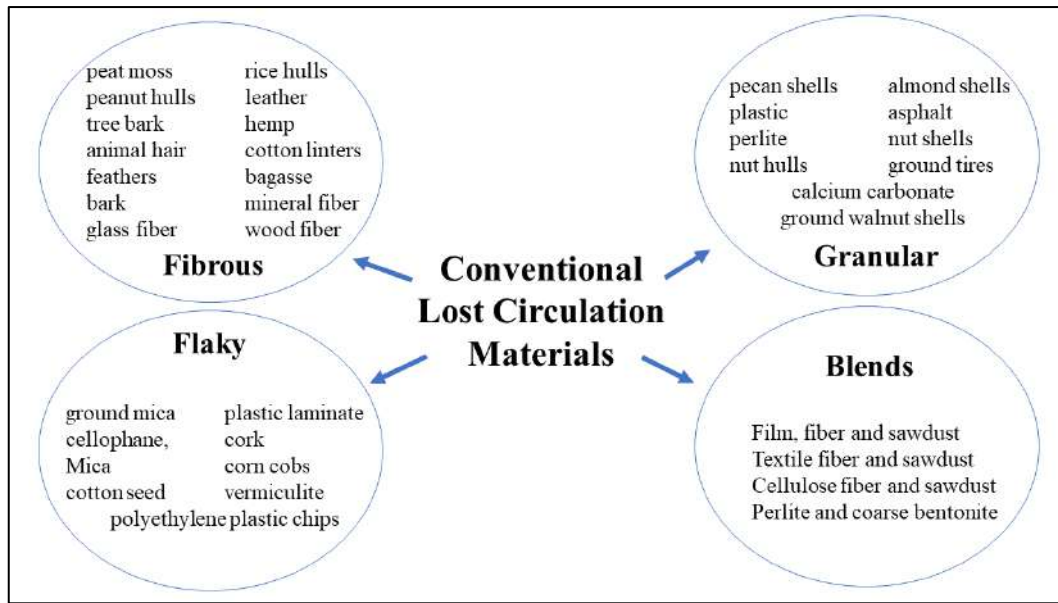


Figure 2.12 Conventional lost circulation materials (Alkinani, 2017)

2.6 Several LCMs and Their Applications

Controlling lost circulation efficiently is a process that requires more than just the selection of a lost circulation material (LCM); it fundamentally requires an engineered approach (Savari et al., 2012). Particulate LCMs, such as ground marble, graphitic carbon, and cellulosic fibers, make up the bulk of the commonly used LCMs. However, the type, shape, size, concentration, composition, and strength of LCMs must be matched to the fracture characteristics. If we are inducing fractures, they may be sensitive to pressure, particularly when the equivalent circulating density (ECD) exceeds the gradient of the fracture while we're in the wellbore strengthening phase. LCMs must be displaceable or degradable to resolve the inadvertent effects of lost circulation on the productive zones to avoid formation damage when used. Possible LCMs include water-soluble, acid-soluble, and hydrolysable materials (Luzardo et al., 2015).

LCMs commonly used in the industry include calcium carbonate, graphite, fibrous materials (mineral, wood, and glass fibers), flake materials (mica, cellophane, and vermiculite), and granular materials (perlite, nut shells, and ground rubber tires). More sophisticated treatments have been reviewed as well, including crosslinked cement (Mata and Veiga, 2004), crosslinked nanocomposite gels in severe losses applications (Lecolier et al., 2005), high-strength pills which combine mineral, synthetic, and cellulosic fibers (Sanders et al., 2010), gunk squeezes (Collins et al., 2010), silicon nanoparticles and ultrasonic curable

nanoparticles and chemical sealants in severe to complete losses ([Abdulrazzaq et al., 2018](#)). Each of these treatments has its benefits and limitations.

Cement plugs are the most common treatment for partial, severe, and total losses, and total loss applications can be enhanced with cement plugs applied with high-viscosity drilling fluids ([Alkinani et al., 2019](#)). Low-concentration LCM pills are often effective for partial losses, but high-concentration acid-soluble LCM are often preferred for severe losses. A summary of typical LCM practices used in the oil and gas industry is presented in Table 2.2.

Table 2.2 Some lost circulation materials used in the petroleum industry

Material	Reference	Classification
Sawdust	Howard and Scott, 1951	Fibrous
Prairie hay	Howard and Scott, 1951	
Bark	Howard and Scott, 1951	
Shredded wood	Howard and Scott, 1951	
Cellophane	Howard and Scott, 1951	Flaky
Mica	Ezeakacha and Salehi, 2018	
Calcium carbonate	Ezeakacha and Salehi, 2018	
Limestone	Howard and Scott, 1951	Granular
Sulfur	Howard and Scott, 1951	
Plastic	Howard and Scott, 1951	
Nut shell	Howard and Scott, 1951	
Cotton seed hulls	Howard and Scott, 1951	
Thermoset rubber	Loeppke et al., 1990	
Coal	Loeppke et al., 1990	
Expanded aggregate	Loeppke et al., 1990	
Gilsonite	Loeppke et al., 1990	
Black walnut	Loeppke et al., 1990	
Resilient graphitic carbon	Savari et al., 2012	
Chemically activated cross-linked pill	Caughron et al., 2002	Pill
Settable treatment pill	Aston et al., 2007	
Shape memory polymer	Mansour et al., 2019	Swellable (grainy)
Magnesium oxysulfate cement	Cui et al., 2021	Cement

2.6.1 Calcium Carbonate and Graphite

Calcium carbonate (CaCO_3) is among the most extensively applied benign Lost Circulation Materials (LCMs), and is used primarily in reservoir areas ([Luzardo et al., 2015](#)). The sealing efficiency of calcium carbonate was reported to improve substantially with synthetic graphite, which is relatively strong and resilient ([Savari et al. 2012](#)). For example, the additive will be more effective in preventing fluid loss with graphite to calcium carbonate ratios of 3:2, compared to either additive in isolation.

Ezeakacha and Salehi (2018) conducted an experimental study of calcium carbonate and mica and documented the impetus to select the appropriate particle sizes for the additives, which would prevent or suppress additional fluid loss during dynamic drilling fluid invasion.

Resilient Graphitic Carbon (RGC) is a high-performance LCM with several favorable functional properties. RGC is minimally affected by the rheology of synthetic-based mud (SBM) and may be pumped at high concentrations through mud motors in a pill form to effectively control lost circulation (Whitfill and Hemphill 2003). RGC will also improve the resiliency of mixtures of RGC and non-resilient material, is non-magnetic (thus safe for magnetic sensitive downhole tools), and lubricates the mixture to assist with reducing torque and drag (Savari et al., 2012). RGC was applied successfully in isolation or as part of a mixture with other LCMs to control seepage losses, lost circulation in depleted sands, and seal vertical and/or horizontal boreholes intersecting faults.

2.6.2 Expandable LCMs

Recently, temperature-responsive (expandable) plugging agents based on shape memory polymers (SMPs) have been highly regarded because of their capacity to both seal fractures and strengthen the borehole (Cui et al., 2021). Mansour et al. (2019) developed a smart expandable LCM created from SMPs to mitigate fluid loss and enhance wellbore strength. In this methodology, the polymers are activated by the natural heat from the formation (Figure 2.13); when this occurs, the LCM expands, and the polymers bridge and seal vugs and fractures while preserving the integrity of the formation pores and other tools used downhole.



Figure 2.13 The novel smart LCM before being activated (left) and after being activated (right) (Mansour et al., 2019).

2.6.3 Cement Technology

Cement is a prevalent lost circulation material (LCM) in the oil and gas industry. Several cement types have been used specifically to mitigate lost circulation, and due to recent advances in cement technology, cement applications are more custom-designed for specific drilling fluid types and specific well conditions. Examples of these custom-designed cement applications include thixotropic and ultra-thixotropic cement slurries, slurries with cello flakes, mica, and CaCO_3 for mechanical bridging, specialty spacers and surfactant packages, and foamed cement for better lost circulation control ([Fidan et al., 2004](#)).

For example, of new advancements in LCMs, Cui et al. (202) proposed magnesium oxysulfate (MOS) cement, which sets quickly, exhibits high strength, and has high acid solubility that may prevent lost circulation. MOS cement consists primarily of MgO , MgSO_4 solution, and appropriate retarders such as citric acid, boric acid, and borax to permit control over the placement and optimum sealing.

2.7 Natural and Biodegradable Materials

The oil and gas industry is increasingly adopting natural and biodegradable loss circulation materials (LCMs), which are being developed to address the issue of finding safer, eco-friendly alternatives to traditional, synthetic, and expensive materials ([Purnomosidi et al., 2021](#)). The need to maintain drilling efficiency while minimizing human and environmental impacts has been driven and aided by regulatory pressure being applied by environmental protection agencies and a growing worldwide desire to lessen human and environmental impacts ([Ismail et al., 2021](#)). The development of natural materials of plant origin for LCMs continues this line of thought because they reduce humans' and the environment's environmental footprint. Also, natural materials are part of a larger drive to reuse waste materials in oil and gas operations; thus, cutting costs and waste to the environment ([Ikram et al., 2021](#)). A classification of various waste materials for this purpose is shown in Figure 2.14.

Regardless of the potential scope for eco-friendly drilling muds, the development of this has barriers such as cost of production, processes for utilization, and the lack of availability of raw materials in sufficient quantities ([Ismail et al., 2021](#)). A range of natural materials, not limited to rice husk, coconut shells, sugarcane ash, and cotton seed hulls, have been utilized to change the properties of drilling muds to prevent lost circulation ([Purnomosidi et al.,](#)

2021). For example, cotton seed hulls are an example of a sustainable LCM that in addition to preventing lost circulation allows for improved lubrication of the bit, whereas coconut coir has been used to seal severe lost circulation zones. Other materials like walnut shells, marble, fibers, and calcium carbonate have been tested using geothermal production environments, with mixed success (Loeppke et al., 1990). In addition to these natural materials, thermoset rubbers and wood-based additives have been identified as efficacious, environmentally-friendly options for lost circulation control (Saleh et al., 2020) A list of commonly used natural and biodegradable LCMs is found in Table 2.3.

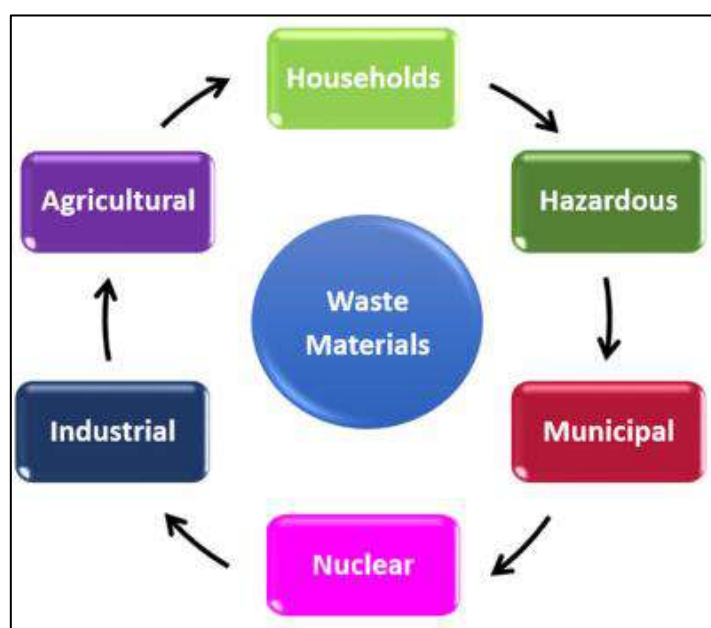


Figure 2.14 Waste classification (Ikram et al., 2021)

Table 2.3 Environmentally friendly materials used as LCMs.

Natural/Biodegradable Material	Reference
Ground cocoa bean shells	Green, 1984
Black walnut	Loeppke et al., 1990
Rice fractions (rice hulls, rice tips, rice straw, and rice bran)	Burts, 1992
Rice fractions (rice hulls, rice tips, rice straw and rice bran)	Burts, 1997
Cotton seed hull	Cremeans and Cremeans, 2003
Coconut coir	MacQuoid and Skodack, 2004
Fibers	Ghassemzadeh, 2011
Apple skin fibers	Ghazali et al., 2015
Crushed palm date seeds	AlAwad and Fattah, 2017
Banana peels	Akmal et al., 2021
Sugarcane bagasse	Akmal et al., 2021

2.7.1 Rice

Rice husk, as an agricultural by-product, has been examined to adopt as a filtration loss additive to water-based drilling fluids. [Okon et al. \(2014\)](#) compared rice husk additive against conventional additives sodium carboxymethyl cellulose (CMC) and polyanionic cellulose (PAC) using a static fluid loss test method. They showed that rice husk substantially reduced fluid loss using 20 g per 350 mL of drilling fluid (approximately 20 lb/bbl) with a reduction of 64.89%, when compared to CMC (62.77%) and PAC (59.57%) additives using 10 g per 350 mL drilled fluid, respectively. The authors also noted that the filter cake from rice husk was thinner even at a higher additive concentration, with reductions of 3.03% and 8.57% in filter cake thickness compared to the CMC and PAC additives, respectively. Rice husk is a sustainable and effective additive to limit fluid loss in water-based drilling muds and may produce cost savings to the petroleum industry. The figure 2.15 shows the rice husk particles of varying sizes.

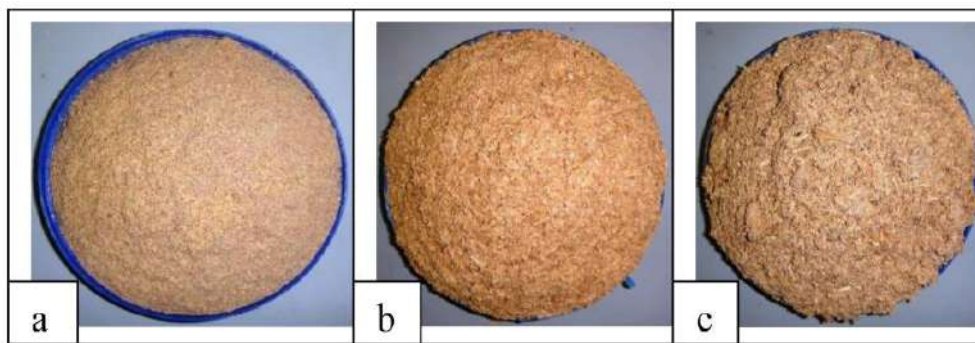


Figure 2.15 (a) Fine particles 125 microns (b) ground particles (c) dried recipe of rice husk ([Okon et al., 2014](#))

2.7.2 Date Tree

New fibrous and particulate LCMs can be engineered from the physio-mechanical processing of date palm tree waste materials ([Ramasamy and Amanullah, 2018](#)). Laboratory comparison using PPT apparatus run under pressures of 500 and 1500 psi, and a temperature 250 °C and a 2-mm slotted disc, indicated that these materials effectively blocked formation pores. Fiber blends engineered from date palm waste materials performed comparably or superior to commercial LCM blends ([Sedaghatzadeh et al., 2021](#)). [Ramasamy and Amanullah \(2017\)](#) further developed a fibrous LCM from the prescribed level of dead date palm trunk debris (Figure 2.16), demonstrating that agricultural waste has promise as a non-

toxic, environmentally friendly, and biodegradable alternative solution to lost circulation material control.

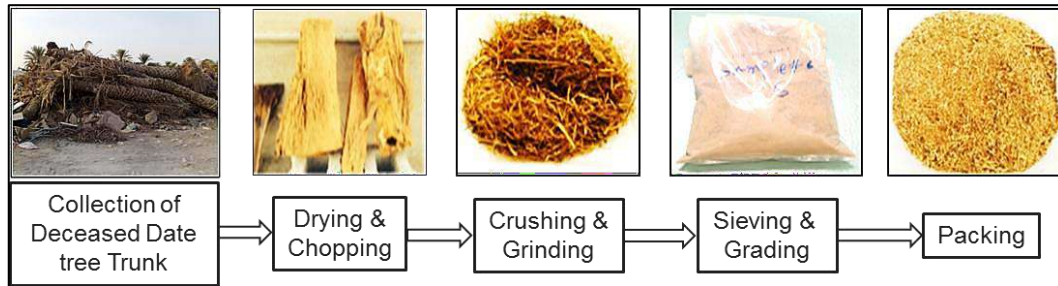


Figure 2.16 Fiber manufacturing process (Ramasamy and Amanullah, 2017)

2.7.3 *Banana*

The study by Akmal et al. (2021) evaluated the use of banana peels (Figure 2.17) and sugarcane bagasse as an alternative to lost circulation material to control fluid loss and improve the filtration properties of drilling fluid in an experimental study. The study indicates that banana peels performed slightly better than sugarcane bagasse in that banana peels had higher contents of crude fiber, cellulose, lignin, and starch, resulting in lower volume of filtrate and thinner mud cake when added to water-based drilling fluid. Sugarcane bagasse was less effective in filtration performance but illustrates it has good environmentally friendly qualities, making it a potential LCM candidate. This study demonstrates the potential of using agricultural waste products as environmentally sustainable and biodegradable replacement LCMs.



Figure 2.17 Banana peel and its powder (Akmal et al., 2021)

2.7.4 *Apple*

Ghazali et al. (2015) provided experimental evidence that fibrous materials from apple skin can function as effective loss circulation materials (LCMs) in drilling fluid applications. The authors reported that the addition of apple skin improved filtration control by increasing the

thickness of the mud cake and the volume of the filtrate when compared to base-drilling fluid. Additionally, depending on the concentration used, apple skin increased the mud cake thickness while decreasing the volume of the filtrate. Overall, apple skin was determined to be a new environmentally-friendly, biodegradable LCM for drilling applications.

2.7.5 Walnut

Deformable and variable particle morphologies of LCMs, such as nut shells, have been shown to block damaged/collapsed large fractures, whether alone or with LCMs. Experimental research has tested the walnut shells and polymer XT to evaluate their effect on the rheology and fluid loss control of water-based drilling muds. The studies shown that walnut shells can serve as an effective material for filling pores and fractures in a lost circulation zone, which presents itself as a promising, eco-friendly alternative to traditional LCMs.

2.7.6 Agarwood

[Azizi et al. \(2013\)](#) assessed agarwood waste as a drilling fluid additive based on its unique properties. The experimental results showed that the filtrate volume for agarwood waste drilling fluid was approximately 13 mL, while it was equivalent to 12 mL for conventional fluid loss control agent starch (under low-pressure low-temperature filter press tests). Based on these findings, agarwood waste was able to be concluded as a valid fluid loss additive for water-based drilling fluids.

2.7.7 Eichhornia crassipes plant

[Purnomosidi and colleagues \(2021\)](#) studied the possible application of the invasive Eichhornia Crassipes Plant (ECP) as lost circulation material (LCM). Their tests showed that both dried and wet fibers had variations in mechanical properties, which were comparable to other anthropogenic biological LCMs. The authors concluded that ECP fibers could effectively plug opened fissures in lost circulation zones, due to their properties of low modulus of elasticity and low stiffness along with low mechanical strength, comparable to bagasse and wood.

[Sedaghatzadeh et al. \(2021\)](#) have also tested an LCM additive based on Eucalyptus Camaldulensis (EUC) bark powder. The authors stated it was fibrous, cheap, environmentally friendly, and abundant. Test results showed that EUC powder improved the rheology of base mud and significantly improved fluid loss. The authors observed, for 100 psi differential pressure (pressure differential across the mud column), initial, total and final

volume fluid loss rates were decreased by 66%, 94%, and 97%, respectively, confirming that EUC powder was a good sustainable LCM additive for use in drilling.

2.7.8 *Durian rind*

[Majid \(2018\)](#) examined the capability of treated durian rind (no pectin), untreated durian rind (with pectin), and fibro seal as lost circulation materials (LCMs) in water-based drilling fluids. The results showed that both treated and untreated coarse durian rind at 30 lb/bbl reduced lost circulation for slot widths of 1 to 3 mm better than coarse fibro seal, which had good performance only for a 1 mm slot disc. In the marble bed tests, the lost mud volumes in the volumes of mud were 10 mL and 25 mL for durian rind samples, and 150 mL for 30 lb/bbl of coarse fibro seal, reflecting the higher plugging ability of durian rind as an eco-friendly LCM.

2.8 Previous Studies

This section provides a detailed review of the current knowledge surrounding Loss Circulation Materials (LCMs), taking into account their significance, classifications, functions and applications in drilling operations after 2010. This literature review looks to clarify the development of LCM technology through a review of recent literature, highlighting their significant role in managing lost circulation issues and the different methods for adapting LCM solutions for unique drilling conditions. Drawing on research from the literature contributes to a thorough understanding of LCMs, especially when optimized drilling performance is the aim, in current petroleum engineering.

[Kumar et al. \(2010\)](#) maintained that a consideration of the particle size distribution of LCMs in isolation is an inadequate measure to productively strengthen the wellbore. They argued that the additional mechanical and physical property of LCM particles is important to achieving effective sealing and fracture bridging, including but not limited to convexity, sphericity, aspect ratio, crush resistance and resiliency. In their study, they assessed some commonly used LCMs such as ground marble (GM), resilient size carbon (RSC), nutshells and cellulosic fibers. Tests confirming physical properties such as aspect ratio, sphericity and convexity were conducted using an optical microscope. Results indicated an overall similarity in shape factors of LCMs as summarized in Table 2.4. The findings highlighted that geometry contributes to the general performance of bridging and wellbore reinforcement.

Table 2.4 Average shape factors for different LCM (Kumar et al., 2010)

Product	Generic Name	Nominal Diameter (μm)	Aspect Ratio	Sphericity	Convexity
GM 150	Ground Marble	150	1.42	0.54	0.96
GM 600	Ground Marble	600	1.57	0.51	0.96
RGC 400	Resilient graphite carbon	400	1.57	0.46	0.90
RGC 1000	Resilient graphite carbon	1000	1.42	0.53	0.91
Ground Nutshells M	Ground Nut Shells	1450	1.50	0.50	0.91
Ground Nutshells M	Ground Nut Shells	617	1.37	0.55	0.92
Ground Rubber	Ground Rubber	300	1.39	0.53	0.88
Cellulosic Fiber	Wood Fiber	1036	1.63	0.44	0.92

Furthermore, the authors performed the crush test for five different LCM particles alone in two sizes; D90 and D50, their results are illustrated in figure (2.18).

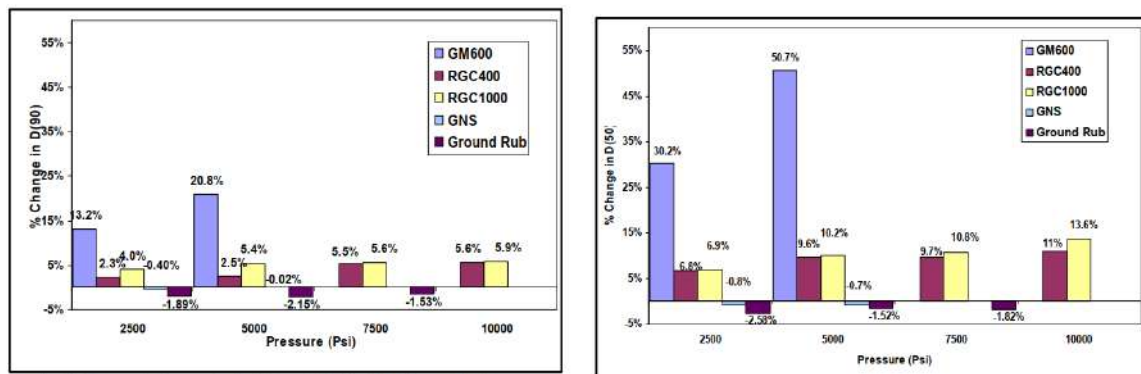


Figure 2.18 Percent change in D90 and D50 of different LCM (Kumar et al., 2010)

Figure 2.19 demonstrates that ground marble (GM) is brittle and exhibits a high compression change while nutshells and rubbers exhibit ductile behavior. Resilient size carbon (RGC 400) efficiently retains and releases pressure due to its reduced surface area. Crush tests showed GM alone is not enough to provide wellbore strengthening; however, when 20% RGC is added (by volume), the percentage change at 5000 psi is reduced by half and appears to improve the bridging performance of the fracture.

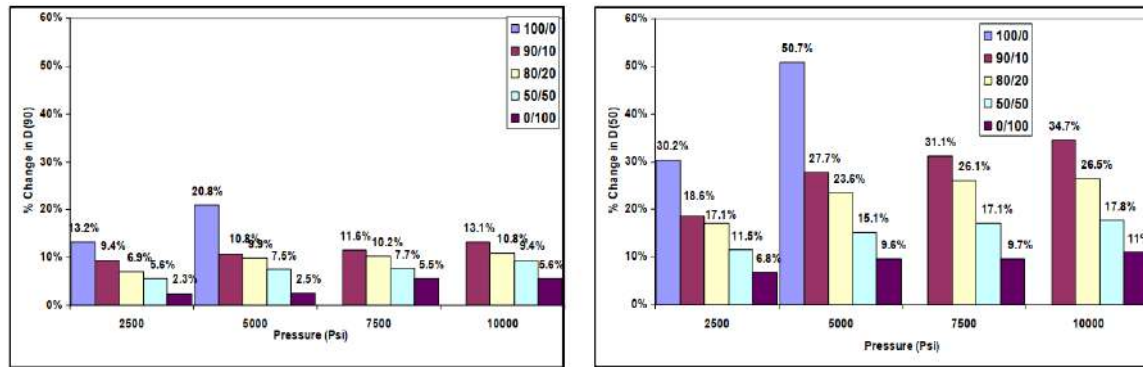


Figure 2.19 Percent change in D90 and D50 for different GM 600/RGC 400 combinations (Kumar et al., 2010)

The combination of ground marble and Resilient Graphitic Carbon (RGC) was determined to be very useful in lost circulation treatments. Lost circulation materials (LCM) are commonly tested using Permeability Plugging Apparatus (PPA) tests with either ceramic discs or straight slots and normally sizes are the only variable considered in the design of the material. However, Kumar and Savari (2011) looked at other properties, like crush resistance and resiliency, which other researchers have ignored. Using a hydraulic tester, they tested the RGC under loads varying from 2500 - 10000 psi to represent the closure of fractures, using a tapered slot (TS) for the PPA test. The authors concluded that RGC is unique in its resiliency and could transfer the property of resiliency to added combinations, especially when combined with ground marble increased the material's crush resistivity, which was supported by the outcome of the field results while testing the approaches with various combinations. The authors concluded that the behavior of these LCM is valuable in the process of designing LCM treatments for very complex wells while utilizing resiliency and crush resistance properties.

Gerner (2012) assessed the bridging capability of an LCM (LC-Lube) in oil-based muds with an equal mixture of oil and water ratios of 60/40 and 80/20. In laboratory testing, the base material had a D50 of 310 μm and was tested across a slot width range of 100 - 500 μm at 8.49 and 16.85 lb/bbl. The findings showed the 60/40 OBM system bridged better at slot widths of 250 μm and 300 μm with a higher concentration of 16.85 lb/bbl. The performance advantage with the 60/40 OBM system continued at the lower concentration but with a lesser degree of measurable performance.

Drilling through Oman's fractured Natih limestone suffered significant losses and packoffs due to swelling shales that resulted in repeated sidetracks. Jain et al. (2013) introduced Engineered Fiber Pills and changed the completion practices of engineers by returning full

returns and allowing successful cementing practices. The use of fiber pills also proved effective in North Oman during a well kill during a flow of gas to stop those flows and reduce losses during drilling operations, cementing, and workovers in depleted reservoirs.

[Okon et al. \(2014\)](#) studied rice husk, an agricultural byproduct, as a fluid loss additive in water-based muds, and results were similar to traditional polymers CMC and PAC. The static fluid loss tests showed that when 20 ppb rice husk was added, the fluid loss was decreased and the filter cake was thinner compared to CMC and PAC. [A.Razzaq and Kzar \(2016\)](#) also evaluated rice as lost circulation material (LCM) and found it to be effective in reducing both partial and complete loss. Furthermore, they concluded that the particle size of the treated material is a considerable, significantly critical property.

In high-permeability or fractured formations, significant loss of circulation can make conventional lost circulation material (LCM) pills and cement plugs ineffective. This was the case in the Mumbai Region, where loss of circulation during drilling through depleted, fractured, and unconsolidated formations exceeded 100 barrels per hour. To resolve this issue, [Rastogi et al. \(2015\)](#) developed a novel Rapid Setting Fluid (RSF) Pill from local magnesium compounds that sets rapidly upon contact with the loss zone.

The RSF pill sets rapidly in the fracture mouth of the loss zone, achieving high compressive strength in 5-6 hours due to time and temperature alone without using hydrostatic pressure. It is non-damaging because it sets at the mouth of the fracture, is non-invasive and dissolves highly soluble in 15% hydrochloric acid. The RSF is designed for bottom-hole temperatures up to 140 °C and has been successfully deployed in a number of Mumbai Offshore wells including from well N_12#3Z and well HG#6H with success in L-III and Bandra Limestone formations.

Polymeric systems could provide a solution to this problem of loss of circulation. [Hashmat et al. \(2016\)](#) investigated commercially available hydrolyzed polyacrylamide (HPAM), as well as an HPAM derivative containing polyethyleneimine (PEI) to use as sealing agents/polymers. They concluded that creating a strong and stable gel is dependent upon the polymer/crosslinker ratios and high polymer concentrations, which was supported by rheology data. At room conditions, both the HPAM/PEI (3/1.2) and A130/PEI (2/1.2) gels were able to seal a zone with a porosity of 36% and a permeability of 300 D, resulting in no losses of mud.

[AlAwad and Fattah \(2017\)](#) investigated crushed palm date seeds as a fracture sealing material (FSM). Testing involved adding the material to drilling fluid and using a modified High-Temperature High-Pressure filtration cell with fractured rock discs. The results demonstrated an effective seal, indicating its potential as an eco-friendly FSM for drilling in fractured formations.

[Ramasamy and Amanullah \(2018\)](#) were the first to develop a new, sustainable lost circulation material (LCM) called "Arc Fiber SF," made from date tree waste collected locally. Their work resulted in a new material that was practical, environmentally friendly, and biodegradable. The researchers ensured that the superfine fibers were processed thoroughly to maximize their ability to control seepage losses. Non-dispersive KCl-polymer drilling muds were then prepared with the added fibrous material to document their control of seepage losses.

The effectiveness of the "Arc Fiber SF" was tested experimentally against a commercially available seepage loss control material using a High-Temperature High-Pressure (HTHP) filter press. At 500 psi and 212 °F, empirical measurements demonstrated that "Arc Fiber SF" was much more effective at controlling fluid loss. This study ultimately showed that this date tree fiber-based LCM is a credible and suitable greener alternative to traditional commercial fibrous LCMs.

In recent years, temperature-responsive shape memory polymers (SMPs) have gained a lot of attention as advanced lost circulation materials (LCMs). [Mansour et al. \(2019\)](#) presents an intelligent, expandable LCM incorporated with these polymers to reduce fluid loss and stabilize the wellbore. This action is automatically triggered by the formation's natural geothermal heat. Once heated, the SMPs resume an expanded shape; therefore, they are capable of bridging and sealing vugs and fractures. One of the key advantages of this technology is that it acts without damaging the production zone pores or drill tool; thus, it provides an ideal sealant which increases the stability of the wellbore.

According to [Elkatatny et al. \(2020\)](#), a new High-Strength Lost Circulation Material (HSLCM) was developed to manage extreme losses in deep wells. This advanced system uses water as a base fluid and is composed of several important components: a setting control additive to determine the set time, a viscoelastic surfactant (VES) to enable viscosity, a defoamer, a salt to improve VES functionality by ionic strength, an acid-soluble weighting additive (ASWA) for density, and a dispersant. Activated from 150°F to 225°F, the ASWA

chemically reacts with water to eventually provide a hard solid plug similar to cement, with the composition given in Table 2.5. The authors summarized the benefit of HSLCM with novel properties below:

- Its thixotropic ability allows for easy placement downhole, hinders gas migration and inhibits flow from thief zones prior to set time.
- After setting, it increases compressive strength and may be used as an isolation plug to bridge severe loss zones.
- The chemistry of the formulation is non-damaging to reservoir formations because it is free from cross-linking gelants, which also improves overall cleanliness and preservation of permeability.
- The authors state that it was successfully field tested, where HSLCM mitigated severe circulation losses from the prior LCM.

Table 2.5 The high strength lost circulation material (HSLCM) (12.5 ppg) formulations at different temperatures (Elkatatny et al., 2020)

Material	Water, ml	Defoamer, ppb	Ionic strength additive, ppb	Setting control additive, ppb	VES, ppb	ASWA, ppb
125 °F	245.3	0.4	10.3	2.6	7.5	257.8
150 °F	245.5	0.4	7.7	5.2	7.5	257.7
175 °F	244.9	0.4	2.5	12.8	7.5	255.8
200 °F	240.7	0.4	2.5	24.8	7.5	248.4
225 °F	236.7	0.4	2.5	36.2	7.5	241.3

Idress and Hasan (2020), created Low-cost Cementitious Materials (LCMs) from orange peel and sunflower seeds. The authors tested fine, medium, and coarse particles at concentrations from 0.8% to 4%. They found that the finest particles, when tested at high concentrations, yielded the best filtration control compared to a commercial nut plug and that a mixture of fine and medium particles yielded those same results. The authors noted that by a range of various optimal size distributions, a more complete seal was achieved, concluding that glazing on various cementitious materials enhanced LCM filtration performance.

Cui et al. (2021) developed a temperature-sensitive expandable plugging agent (SMP-LCM) consisting of shape memory epoxy polymers and foams. Using sand beds to simulate high-permeability zones, testing confirmed that SMP-LCM effectively sealed these zones. Unlike traditional LCMs such as nutshells, SMP-LCM prevents downhole tool plugging while increasing sealing performance.

According to [Hamza and coworkers \(2022\)](#), they tested a rapid-set polymeric pill for severe losses in highly fractured formations. The study examined a crosslinked polyacrylamide/Aluminum-Acetate (PAM/AlAc) system looking at its rheology, gelation, and sealing of fractures. The results showed that the Aluminum-Acetate crosslinker created a strong gel over a wide temperature range (75°F to 260°F) and that the gelation time was controllable over a pH range of 3.5-8.5. The formulation was highly effective and stable, and incorporation of a very small amount of Nanosilica (<1%) substantially increased the strength and stability of the gel. In a practical setting from testing seal fractures, the pill began functioning and established a very strong plug which held differential pressures up to 700 psi, indicating the potential for significant extenuating loss zones.

[Elahifar and Hosseini \(2023\)](#) used and reworked the idea from [Anna M. Kelley et al. \(2022\)](#) to create a new blend of commitment-based smart LCM that would localize control of sealing in fractures remotely. They performed an experimental study to look at Mica, Wheat Straw, Oak Shell, and Sugarcane Bagasse Fiber sizes, in a mud system with water. They then tested 1000 and 3000-micron fractures from their field data using the local completion materials for varying concentrations in experiment (e.g. Oak Shell at the concentrations from 3-10 ppb). Their findings show that the combination blends were superior to the single LCM materials, and the best single material was Oak Shell. The most significant result with this mixed composite blend was its ability to seal a 3 mm fracture, whereas the traditional materials could not seal fractures of this size. This blended LCM is a modest solution for severe lost circulation.

Although a great deal has been written on lost circulation, there is still a lack of experimental evaluations of natural, biodegradable lost circulation materials (LCMs), including agricultural waste and plant fibers. Some materials like rice husk and straw show potential; however, no studies have tested their performance under high pressures and high temperatures (HPHT), such as those found in Northern Iraq. Similarly, Pomegranate Peel appears to have been seldom, if ever, studied as an LCM.

This study seeks to address these gaps by experimentally assessing Pomegranate Peel as a natural LCM under HPHT conditions. This study seeks to provide factual and beneficial data related to Pomegranate Peel for Northern Iraqi fields while recognizing the industry's necessary transition from synthetic to environmentally friendly fluids used in drilling.

3 Experimental Work

3.1 Introduction

This chapter describes the experimental study to assess the effects of a number of loss control materials on lost circulation problems in Northern Iraqi oil fields. The experiments were performed to closely simulate the field conditions and used a custom-made setup consisting of a cylindrical core holder attached to a high-pressure system that could generate flow pressures of varying amounts. Real and synthetic drilling fluids were used to represent the actual drilling. The chapter also describes the use of a loss control material to address the problems of lost circulation under controlled laboratory conditions with descriptions of the materials, specifications, and procedures used to experiment with the effectiveness of different loss control materials.

3.2 Materials Used

The materials harnessed for the experimental investigations encompass a curated assortment of loss control agents. The selection process was underpinned by the inherent potential of these materials to alleviate lost circulation issues through their ability to seal fractures and pore apertures inherent to the geological formations.

3.2.1 Water

As the most important and major constituent of water-based drilling muds, the volumetric basis is water, because it is inexpensive and widely available. Water has distinguishing physical and chemical properties related to its high surface tension and dielectric constant, as well as its heat of fusion and heat of vaporization compared to other liquids. The solvent capacity of water is also key and significantly contributes to its importance in drilling operations.

3.2.2 Bentonite

Bentonite, an important commercial clay, is an integral component of freshwater drilling fluid formulations. Bentonite consists of a minimum of 85% montmorillonite and serves an essential purpose in freshwater drill muds, owing to its unique properties ([ASME, 2005](#)). When Bentonite is added to water, it undergoes a significant swelling process and produces a viscous slurry that is excellent for suspending solids.

3.2.3 Caustic Soda

Sodium hydroxide (caustic soda, NaOH) performs the task of pH adjustment in water-based muds by providing hydroxyl (OH) ions to it. It dissolves easily and separates into Na⁺ ions and OH⁻ ions in water. It is mainly used to increase or maintain the pH of a mud, precipitate magnesium (Mg²⁺) and restrain calcium (Ca²⁺) in hard or seawater systems. Additionally, it reduces the corrosion potential of the mud, and neutralizes acidic gases, such as CO₂ and H₂S. General concentrations fall in a range of 0.25 - 4 lb/bbl, depending on water chemistry and type of mud. In seawater or buffered fluids, a concentration of 1.5 - 2 lb/bbl is typically enough to precipitate magnesium and convert calcium to lime. Properties of caustic soda are presented in Table (3.1) ([Alcochem Minerals, 2018](#)).

Table 3.1 Physical Properties of Caustic Soda ([Alcochem Minerals, 2018](#))

Property	Value	Unit
Meting point	320-325	°C
Boiling point	1385-1390	°C
Density at 25°C	1.15	kg/dm ³
Solution rate: (100g in 100ml water at 25°C)	22	s
Heat capacity at 25°C	2.01	J/g.K
Heat of Fusion at 15°C	167.5	J/g
Standard Heat of Formation at 25°C	10.67	kJ

3.2.4 Carbonate Calcium (CaCO₃)

Calcium carbonate is a frequently utilized loss control material (LCM) in drilling and is effective in solving lost circulation problems faced by drillers. The calcium carbonate particles perform in various ways: finer particles can be dissolved in acid for the circulation channels, coarser particles can plug the voids in the formation to prevent the fluid loss, and when used in a combination with other LCMs, calcium carbonate forms a barrier to fluid migration. The physical properties of calcium carbonate are given in Table (3.2).

Table 3.2 Physical Properties of CaCO₃ ([Ezeakacha and Salehi, 2018](#))

Property	Value
Specific Gravity	2.6-2.7
Water Soluble Content	< 1%
Solubility in 15% HCl	> 98%
Moisture Content	< 2%

Lost circulation is a prevalent problem in Northern Iraqi oil fields, particularly in reservoir formations that have fractures. Lost circulation materials (LCMs) are routinely used to mitigate the problem, and calcium carbonate (CaCO₃) is the most commonly used. To make

comparisons, different sizes of CaCO_3 particles were obtained from Pulsar Petroleum Company and taken to the lab for testing; these different CaCO_3 particle sizes have been categorized as fine (74–250 μm), medium (250–850 μm), and coarse (850–3350 μm) size fractions, as illustrated in Figure 3.1.



Figure 3.1 Fine, medium and coarse sized of CaCO_3 LCM

3.2.5 Pomegranate Peel (PP)

Pomegranate peel, or the byproduct of *Punica granatum*, is around 30% of the fruit. It contains important minerals (K, Ca, P, Mg, Na), polysaccharides, and bioactive materials such as phenolics, flavonoids, proanthocyanidins, and ellagitannins including punicalagins (Jalal et al., 2018). The properties of the pomegranate peel were summarized by Jalal et al. (2018) in their table in Table 3.3, and it suggests using pomegranate peel as a nutritionally valuable compound in food and chemical applications. Pomegranate peel has also been used in the field of petroleum engineering. For the winter of 2025, pomegranate peel samples were collected and sun-dried in their powdered forms (Figure 3.2). To illustrate the difference in particle size, the pomegranate peel powder was divided into fines, medium, and coarse particle sizes using standard mesh sieves with results provided in Table 3.4 following A.P.I. RP 13C.

Table 3.3 Chemical, Physico-chemical and Functional of PP (Jalal et al. 2018)

Properties	Property	Value	Unit
Chemical	Moisture	12.48 ± 0.07	%
	Protein	3.26 ± 0.14	%
	Fat	1.73 ± 0.08	%
	Ash Content	3.31 ± 0.05	%
Physico-chemical	Ph	4.83	--
	Lightness	64.14	L
	Redness	7.23	a
	Yellowness	16.86	b
Functional	Water-Holding Capacity	4.84	gm water/gm powder
	Oil-Holding Capacity	5.83	gm oil/gm powder
	Emulsifying Capacity	30.78	mL/100 mL
	Emulsifying Stability	90.16	mL/100 mL

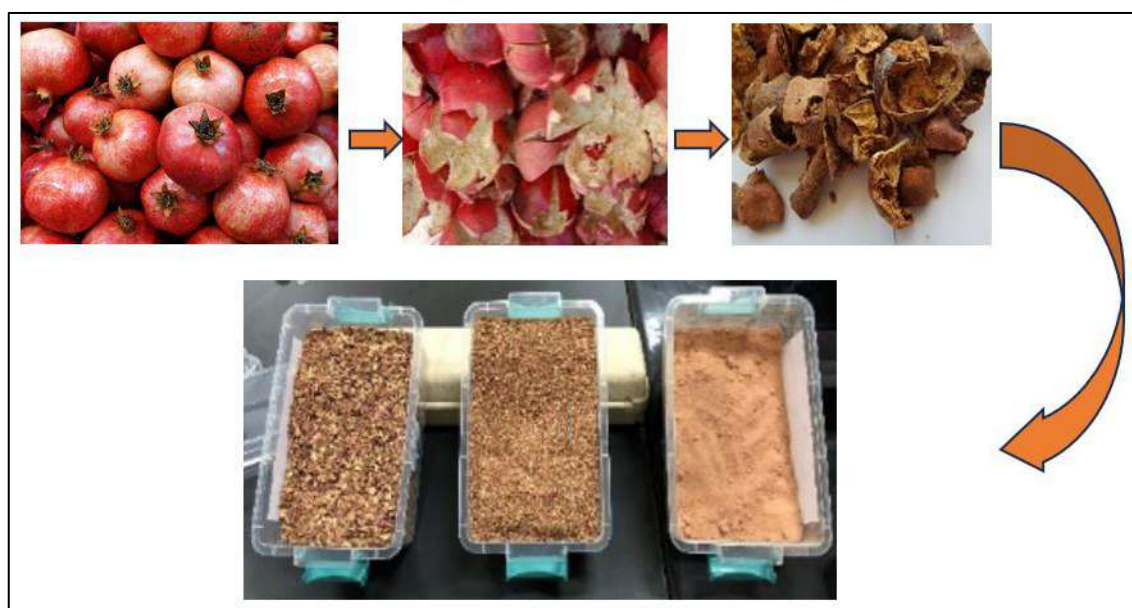


Figure 3.2 Preparation of different sizes of PP powder

Table 3.4 API-RP-13C standard mesh and micron sizes

LCM Grade	Microns	Mesh Sizes
Fine	< 75	> 200
Medium	75 - 250	60 – 200
Coarse	250 - 1000	18 – 60

3.2.6 HCl Solution

While LCMs are effective for sealing fractures and retaining drilling mud, they may inadvertently restrict permeability of the formation, which will adversely affect production—a more severe concern if inappropriate materials are used in reservoir zones. To avert such issues, LCMs that are introduced into reservoir formations must be soluble in the formation fluids to not impede flow or production. It is therefore important to conduct a preliminary assessment of the solubility of any LCM prior to its introduction into the formation. In this study, the solubility of pomegranate peel (PP) LCMs was examined using a 15% hydrochloric acid (HCl) solution to examine their potential for use in reservoir formations.

3.3 Apparatus Utilized

For this experimental evaluation of drilling fluid rheology and filtration, an appropriate suite of equipment was selected that would permit measurement of the key characteristics. A rotational viscometer was employed to measure various viscosities and flow behavior at

assorted shear rates, and a high-pressure filter-cell apparatus was deployed that would assess filtration performance to assist in studying filtration rate and filtration cake formation under conditions of a downhole situation. As a collective, these apparatuses auto provide insights into the mud behavior under an applied low-stress and mud capacity to alleviate fluid loss to improve drilling performance and wellbore stability. The apparatuses were provided by the Petroleum Engineering Laboratories in Koya University.

3.3.1 Mud Balance

The four-scale mud balance (illustrated in Figure 3.3.) measures the density of drilling fluids and cement slurries, which are important properties in drilling operations. The apparatus consists mainly of a mud-cup at one end of a beam, and a counterweight at the other end, along with a movable rider weight along a scale that is marked, and a level bubble that is used to calibrate the density readings that the tester makes from each of the two ends of the apparatus. The front scales to measure density range from 6.5–23 lb/gal, and 0.79–2.72 g/cm³, while the back scales range from 49–172 lb/ft³, and 340–1190 psi per 1000 ft.



Figure 3.3 Four scale mud balance

3.3.2 Viscometer

The Model 900 Viscometer (Figure 3.4) was employed to determine the plastic viscosity, yield point, and gel strength of drilling fluids. This is a rotational viscometer with a coaxial cylinder design that measures the torque induced by fluid resistance acting between the rotor and bob, which is then measured as an angular displacement converted by a transducer. The processor determines the fluid properties based on the shear rate, the angle of movement of the bob, and torque. Advanced stepper-motor technology permits accurate and repeatable measurements, even at extremely low shear rates (0.01 1/s). In the field, a button push (MUD or CEM) initiates standard procedures for API methods for mud or cement rheology.



Figure 3.4 Model 900 viscometer

3.3.3 pH Meter

A pH meter is an important tool in the analysis of drilling mud, especially for monitoring the acid or base strength of the fluid, in stabilizing mud, in corrosion control, and in protecting equipment and formations. Accurate determination of pH provides operators the information necessary to make adjustments to additives to maintain ideal conditions, which will yield the greatest drilling efficiency and the least (or no) harmful reactions. Additionally, pH monitoring helps address environmental compliance by preventing the accrual of overly acid or base mud for disposal into the environment, thus providing protection to both the operation and the ecology.



Figure 3.5 pH meter

3.3.4 Mud Mixer

Drilling fluids are typically composed of a base liquid and additives, whether dissolved or dispersed in an orderly and reproducible mixture. This may include water-soluble polymers or resins, fine dispersible solids, such as clays, and soluble salts. The mixture will then be blended or sheared to achieve the desired consistency and then the mixture will be allowed to "age" under either static or dynamic conditions at varying temperatures to develop the desired rheological and filtration characteristics. Three-Speed Hamilton Beach Mixers (Figure 3.6) were used for laboratory preparation, which has individual speed controls for each spindle. They can also mix cement for field or laboratory tests.



Figure 3.6 Three-Speed Hamilton Beach Mixers

3.3.5 Grinder

An Electric Grain Grinder (see Figure 3.7) was used for the purpose of grinding dried pomegranate peel into powdered form for use in experimental work. The Electric Grain Grinder can process a variety of dried foodstuffs, operates at a high motor speed of 34,000 rpm, and is therefore, more efficient than grinding manually which requires considerably more time. Users can adjust the speed of rotation to control particle size, and produce fine, medium, and coarse powders (a mesh range of 20 to 300). The powders were processed to three different classifications or types (fine, medium, and coarse) immediately following grinding in accordance with API-RP-13C using both mesh and micron sizes, to ensure uniformity for experimental use (see Figure 3.7).



Figure 3.7 Electric Grain Grinder and standard mesh sieves

3.3.6 *Dynamic HPHT Filter Press*

Two forms of filtration occur while the work is being drilled and completed. Static filtration occurs while there is no circulation of drilling fluids, and in that case, the mud cake builds up over time and the filtration rate decreases. Dynamic filtration occurs while the drilling fluids are circulated, which erodes the mud cake. Because static and dynamic filtrations are not measured the same for different drilling fluids, it is important to have a precise measurement of dynamic filter loss.

The HPHT Dynamic Filter Press (Figure 3.8) is the main equipment within this study which addresses the shortcomings of the traditional static filter press and produces results that are more representative of conditions within a borehole. The HPHT Dynamic Filter Press can accurately measure the filtration properties of drilling fluids and cement slurries at both dynamic and static conditions, which will allow reliability, high quality and safety during drilling.

The press operates to:

- Test static filtration and mud cake buildup under static conditions at temperatures ranging from room temperature up to 232 °C; with pressures for the sample cup of < 1300 psi, differential pressure for filtration of 600 psi and a filtration area of 22.6 cm².
- Test dynamic filtration conditions of drilling fluids at temperatures up to 150 °C while meeting similar sample cup, differential pressure and area specifications.
- Obtain substantial measurements of welding cement slurries with two filter screens.

High pressure nitrogen gas provides the applied pressure to complete all experiments, as seen in Figure 3.8.



Figure 3.8 Dynamic HPHT Filter Press

3.4 Experimental Work

3.4.1 Mud Preparations

In this research, we produced a total of 28 different formulations of drilling mud, all of which are detailed in Table 3.5 and can be grouped into five general classifications:

1. **Reference Mud (RM):** Same as appendix A. Made in accordance with API-SPEC-13A-2010. Without additive.
2. **Calcium Carbonate (CaCO_3) LCM Mud:** Contains CaCO_3 additive, with differing particle size and concentration.
3. **Pomegranate Peel (PP) Additive Mud:** Contains PP additive, with differing particle size and concentration.

Table 3.5 Formulated Muds Composition

Mud No.	Bentonite (gm)	Water (ml)	NaOH (gm)	CaCO ₃ (ppb)			PP (ppb)		
				F*	M*	C*	F	M	C
1	80	1400	2	--	--	--	--	--	--
2	80	1400	2	5	--	--	--	--	--
3	80	1400	2	10	--	--	--	--	--
4	80	1400	2	15	--	--	--	--	--
5	80	1400	2	20	--	--	--	--	--
6	80	1400	2	25	--	--	--	--	--
7	80	1400	2	30	--	--	--	--	--
8	80	1400	2	--	5	--	--	--	--
9	80	1400	2	--	10	--	--	--	--
10	80	1400	2	--	15	--	--	--	--
11	80	1400	2	--	--	5	--	--	--
12	80	1400	2	--	--	10	--	--	--
13	80	1400	2	--	--	15	--	--	--
14	80	1400	2	--	--	--	5	--	--
15	80	1400	2	--	--	--	10	--	--
16	80	1400	2	--	--	--	15	--	--
17	80	1400	2	--	--	--	20	--	--
18	80	1400	2	--	--	--	25	--	--
19	80	1400	2	--	--	--	--	5	--
20	80	1400	2	--	--	--	--	10	--
21	80	1400	2	--	--	--	--	15	--
22	80	1400	2	--	--	--	--	20	--
23	80	1400	2	--	--	--	--	25	--

Mud No.	Bentonite (gm)	Water (ml)	NaOH (gm)	CaCO ₃ (ppb)			PP (ppb)		
				F*	M*	C*	F	M	C
24	80	1400	2	--	--	--	--	--	5
25	80	1400	2	--	--	--	--	--	10
26	80	1400	2	--	--	--	--	--	15
27	80	1400	2	--	--	--	--	--	20
28	80	1400	2	--	--	--	--	--	25

3.4.2 Measurements

3.4.2.1 Density and pH Measurements

Mud density was measured with the four-scale mud balance, with attention to avoid errors induced by air pockets. pH was measured initially with the 0-14 pH papers and readings were obtained multiple times for as accurate a measurement as feasible. pH readings were further checked with a pH meter to confirm reliable measurement of the mud's acidity or alkalinity.

3.4.2.2 Rheological Properties Measurements

The rheological properties of the drilling fluids were examined with the Model 900 Viscometer at six different speeds. Approximately 170 mL of fluid was placed into the viscometer cup and was sheared in the gap between the inner bob and the outer sleeve until the fluid became stable, usually within 5 minutes. The measurements were made at 600, 300, 200, 100, 6, and 3 rpms. Plastic viscosity (PV) and yield point (YP) were calculated with the standard formulas.

$$PV = \Theta_{600} - \Theta_{300} \quad \text{eqn. (3.1)}$$

$$YP = \Theta_{300} - PV \quad \text{eqn. (3.2)}$$

Plastic viscosity (PV) is measured in centipoises (cP) and the yield point (YP) is measured in lbf/100 ft²; (where Θ_{600} and Θ_{300} are dial readings at 600 and 300 rpm,) Gel strength is measured at a low shear rate (3 rpm) after being allowed to rest for two intervals, (first 10 seconds after being sheared at 600 rpm for 5 minutes ["10 sec gel strength"], and the second after resting for 10 minutes in a static position ["10 min gel strength"]). The gel strength

measurement in lbf/100 ft² represents each mud's ability to maintain viscosity throughout round trips.

3.4.2.3 Solubility Measurement

The solubility of all of the LCM powders was assessed in 15% hydrochloric acid (HCl) in order to obtain information on the dissolution characteristics and chemical behavior of the powders. A known weight of powder was placed into a glass container, after which a known volume of 15% HCl was added to the glass container. The container was stirred gently, and the mixture was allowed to sit so observations could be made regarding effervescence and/or color change. At the end of the allotted time, the solution was filtered to remove undissolved residues, which were dried and weighed to obtain the insoluble fraction.

3.4.2.4 Filtration Rate and Cake Thickness Measurements

This research aimed to assess the filtration characteristics of drilling muds formulated (Table 3.5) using a Dynamic High-Pressure High-Temperature (HPHT) filter press to determine similar situations for high-pressure, high-temperature reservoirs. Mud samples were prepared with care to ensure consistency with comparability and conditioning them to the desired temperature and pressure.

Each are pre-loaded, sealed, and went under a differential pressure of 500 psi for a temperature of 50 °C and 100 rpm rotation dynamic mode while replicating conditions of a northern Iraq reservoir environment. The HPHT filter press has a filter paper and modulation mode for using high pressure with temperature, which was calibrated correctly before testing. Filtrate volume was visually tracked at real time to evaluate filtration rate, and the resulting mud slurry cake was measured to analyze thickness characteristics indicating mud filterability and under its barrier formation characteristics.

All trials were documented and interpreted using experimental data of given filtrate volume, mud cake thickness, pressure, and temperature. Although the difference in mud formulations under study indicated cases of improved filtration performance under HPHT characteristics. Results were outlined within a comprehensive document exploring for suitability of each mud formulation for high-pressure high-temperature drilling application

4 Results and Discussions

4.1 Introduction

The previous chapter has introduced the experimental framework aimed at determining the performance of several distinct loss control materials (LCMs) in mitigating lost circulation while drilling in the Northern Iraqi oil fields. This chapter will detail, discuss and critically evaluate results, and summarize the relevant performance of LCMs under the various experimental conditions and scenarios.

The study began by testing a baseline water-based mud comprising water, bentonite, and caustic soda; this would provide data on the inherent fluid loss. The next round of testing would include conventional LCMs; calcium carbonate (CaCO_3) was chosen for evaluation. The final round of evaluation would consist of the newly developed natural and biodegradable material, Pomegranate Peel (PP), tested at concentrations of 5–25 ppb.

The variables and measures used included a vast range of both basic measures such as mud density and pH, along with more comprehensive measures such as rheology. Other parameters including solubility, filtration rate, and mud cake thickness when applicable were established to determine the practical performance of each LCM.

4.2 Drilling Fluid Density

Mud density is a significant property of drilling fluids that is required to control subsurface pressures. High density mud can lead to lost circulation and formation damage, while too low density can lead to kicks and blowouts. Thus, it is important to stay within the recommended density range. For unweighted water-based mud, typical density is 8.5-9 ppg. The reference mud of "mud no. 1" in Table 3.5 was generated according to the specified composition in Table 4.1.

Table 4.1 Composition of the reference mud (RM)

Material	Quantity	Unit
Bentonite	80	gm
Water	1400	cc
NaOH	2	gm

Given the ascertainable density and volumetric properties of all constituent materials within the reference mud, it becomes feasible to compute its density utilizing the expression presented in Equation (4.1).

$$\rho_{water}V_{water} + \rho_{bentonite}V_{bentonite} + \rho_{soda}V_{soda} = \rho_m V_m \quad eqn. (4.1)$$

In addition to densities being calculated, densitometer measurements were taken in order to calibrate the mud balance. The reference mud (RM) measured in at 8.61 ppg. Densities for all other samples (Table 3.5) were measured using a standard or pressurized mud balance (the pressurized mud balance was used in foamed muds). The effects of LCM particle sizes, fine, medium, and coarse are quantified in Tables 4.2–4.4; graphs of their effect can be seen in Figures 4.1–4.3.

Table 4.2 Effect of Fine sized LCM on mud density

LCM Material	Concentration (ppb)	Density (ppg)
Fine sized CaCO ₃	5	8.70
	10	8.80
	15	8.85
	20	8.95
	25	9.00
	30	9.07
Fine sized PP	5	8.59
	10	8.55
	15	8.50
	20	8.48
	25	8.45

Table 4.3 Effect of Medium sized LCM on mud density

LCM Material	Concentration (ppb)	Density (ppg)
Medium sized CaCO ₃	5	8.70
	10	8.75
	15	8.80
Medium sized PP	5	8.6
	10	8.58
	15	8.55
	20	8.45
	25	8.38

Table 4.4 Effect of Coarse sized LCM on mud density

LCM Material	Concentration (ppb)	Density (ppg)
Coarse sized CaCO ₃	5	8.70
	10	8.77
	15	8.80
Coarse sized PP	5	8.61
	10	8.60
	15	8.58
	20	8.55
	25	8.53

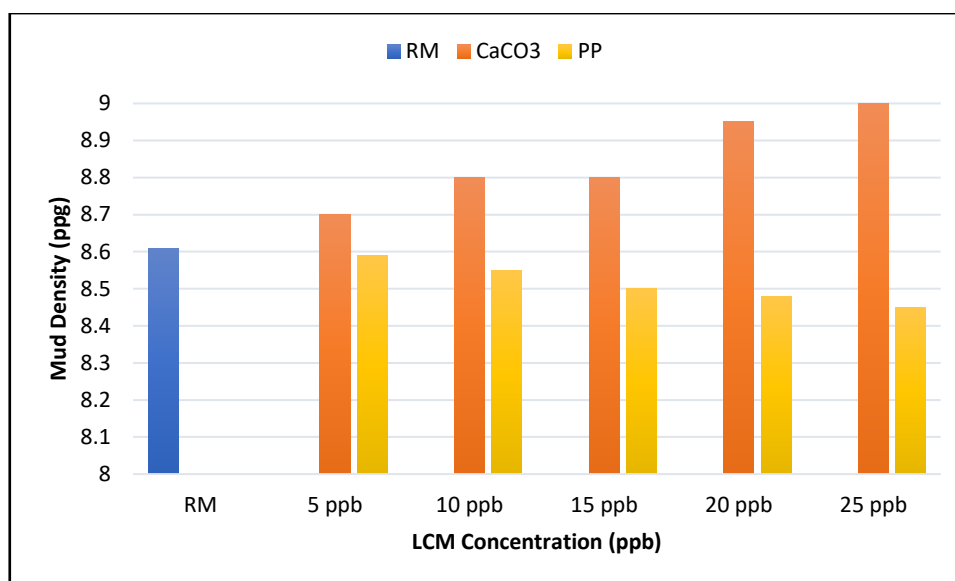


Figure 4.1 Fine sized LCM vs. mud density

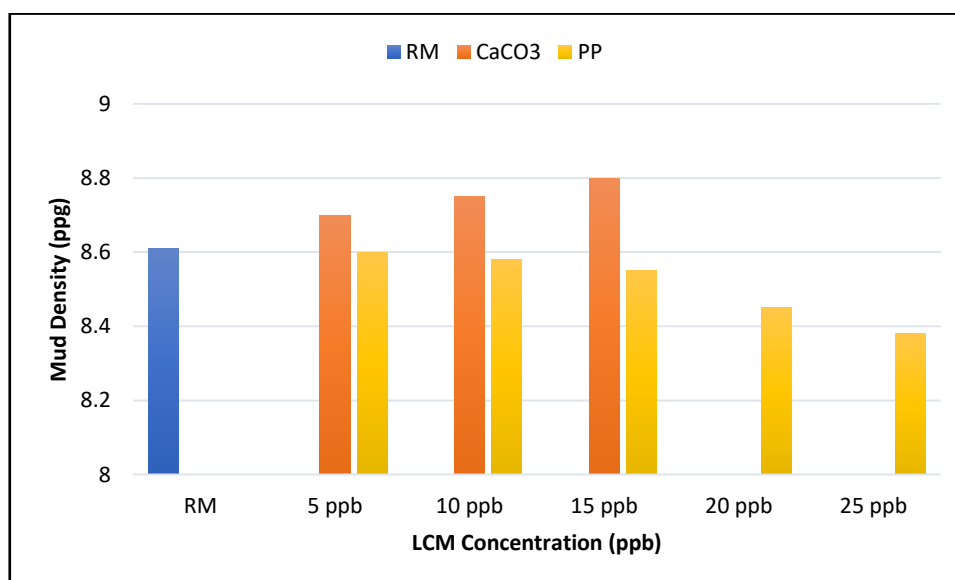


Figure 4.2 Medium sized LCM vs. mud density

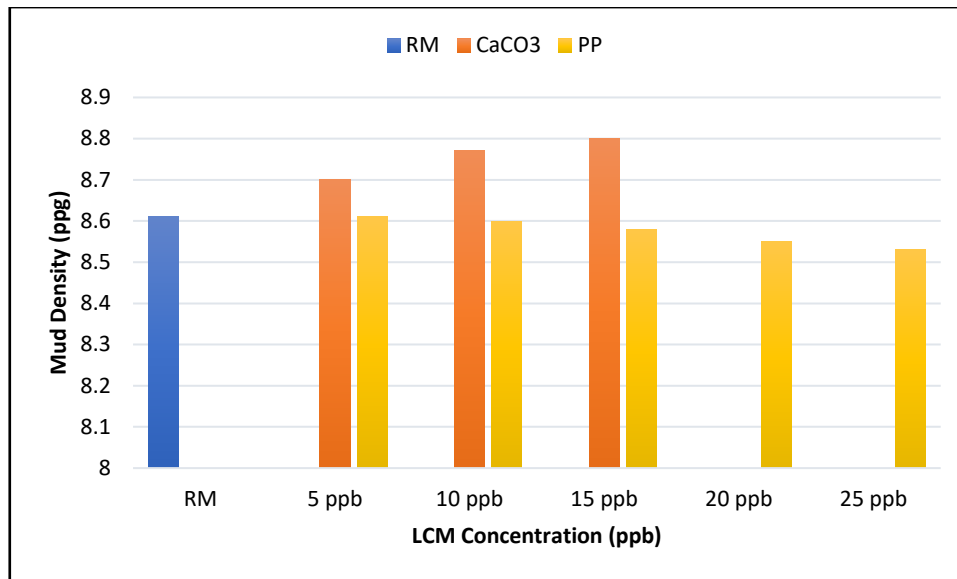


Figure 4.3 Coarse sized LCM vs. mud density

According to the data, the addition of calcium carbonate (CaCO_3) to the reference mud increases its density, at times exceeding 9 ppg because it has improved over grounded specific gravities. The higher density material is advantageous for stability and integrity of the mud when flowing in challenging, and/or high-pressure formations, but often comes at the expense of mud pressure too high and/or lost circulation due to the treatment of weak restrictive zones, supplying further grievance to the usual LCMs.

On the other hand, dosages of Pomegranate Peel (PP) have a lower impact on mud density and may prevent small marginal decreases in mud density. For PP, the threshold was 25 ppb, while for the intermediate powder, the threshold was only 20 ppb. This low amount of density change is a favorable attribute for PP LCMs.

The absence of values in the tables and figures mirrors unfavorable outcomes in other measurement aspects, such as pH, viscosity, or filtration rate. As one example, 20 ppb of coarse CaCO_3 was excluded from the report due to a significant undesired increase in filtration rate. This phenomenon underscores the necessity to look at multiple parameters to assess the suitability of an LCM.

4.3 Drilling Fluid pH

The pH of the drilling mud, is vital for the stability of the fluid, the rheology, the suspension of cuttings and drilling equipment. Consistent maintenance of the mud pH at an optimal range of 8 -10.5 is important to prevent corrosion and facilitate drilling operations. [Gamal et al. \(2019\)](#) also assert beneficial effects outside of that range stated above when pH is

maintained between 9 and 10, that plastic viscosity is also reduced which allows for increased penetration rates and lower pump pressures which results in the filter cake being thinner and allows for less sticking of the pipe which provides environmental benefits. Therefore, monitoring and managing the pH of the drilling mud is not only essential for drilling efficiency but also for operational costs and damaging equipment. This demonstrates the essential purpose of pH in water-based mud systems produced with bentonite.

The pH of a reference mud (“mud number 1” in Table 3.5) was taken with a pH meter to be pH = 12, rising above the recommended, typical pH range. The pH of all other formulations in Table 3.5 was taken for relative comparisons with the reference mud. These results are summarized in Tables 4.5–4.7 and shown in Figures 4.4–4.6.

Table 4.5 Effect of Fine sized LCM on mud pH

LCM Material	Concentration (ppb)	pH
Fine sized CaCO ₃	5	12.00
	10	11.90
	15	11.80
	20	11.80
	25	11.60
	30	11.30
Fine sized PP	5	10.30
	10	9.90
	15	9.50
	20	8.10
	25	7.70

Table 4.6 Effect of Medium sized LCM on mud pH

LCM Material	Concentration (ppb)	pH
Medium sized CaCO ₃	5	11
	10	11.1
	15	11.2
Medium sized PP	5	10.2
	10	9.50
	15	7.00
	20	8.90
	25	8.00

Table 4.7 Effect of Coarse sized LCM on mud pH

LCM Material	Concentration (ppb)	pH
Coarse sized CaCO_3	5	11.60
	10	11.70
	15	11.90
Coarse sized PP	5	11.40
	10	10.50
	15	10.30
	20	9.90
	25	9.10

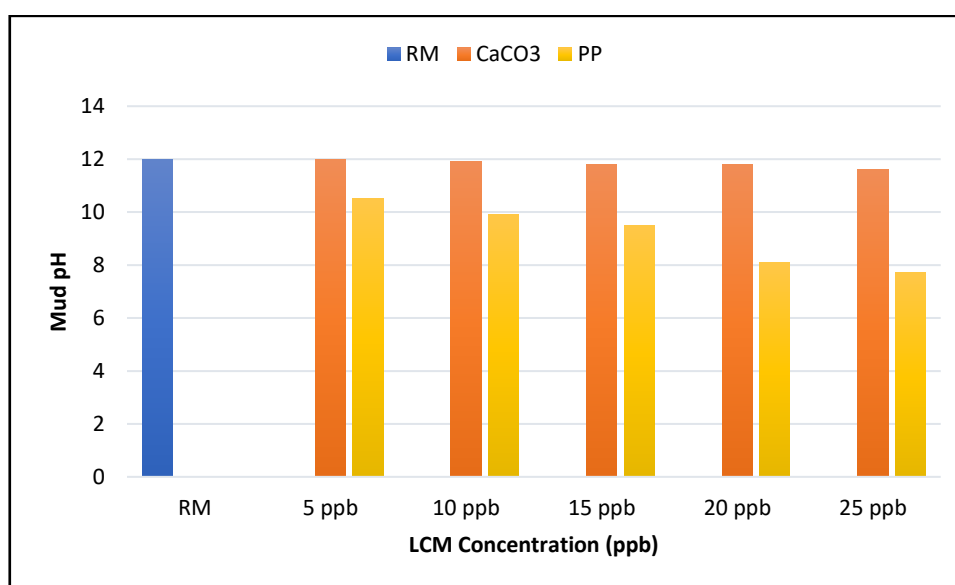


Figure 4.4 Fine sized LCM vs. mud pH

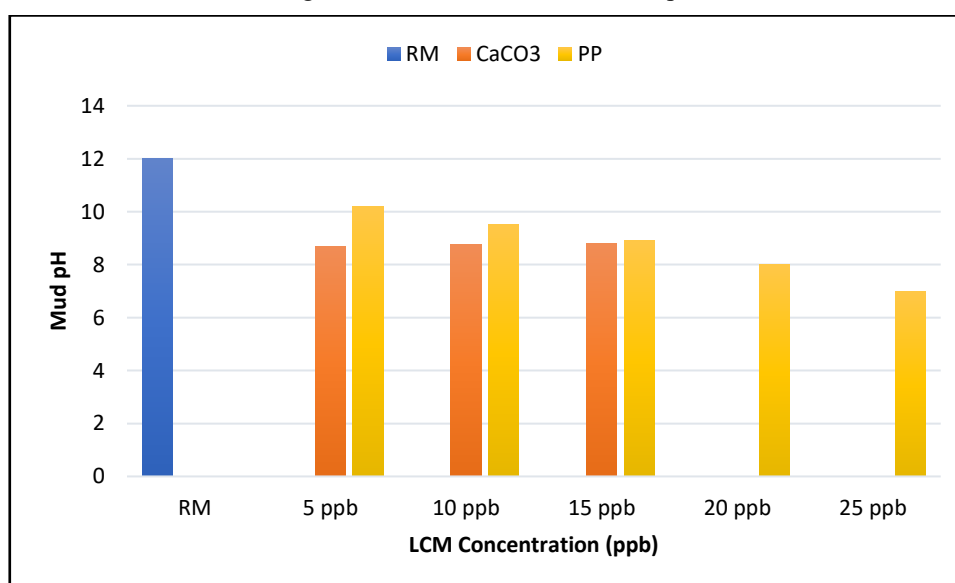


Figure 4.5 Medium sized LCM vs. mud pH

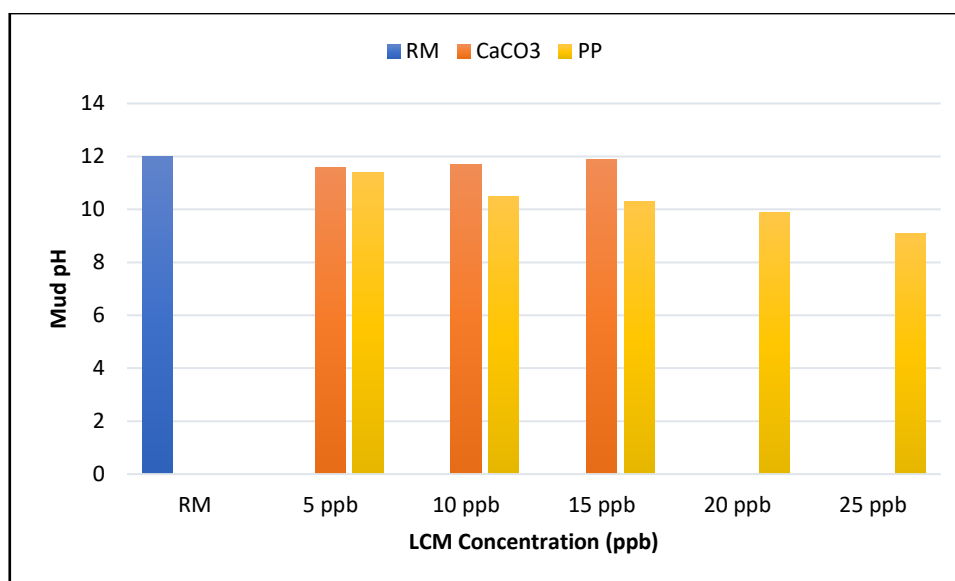


Figure 4.6 Coarse sized LCM vs. mud pH

The findings suggest that gums containing calcium carbonate (CaCO_3) or Pomegranate Peel (PP) generally result in a decrease in pH for mud samples. While reducing the high pH of the reference mud initially is generally needed, the size and concentration of particles can add under- or over-acidifying potential. For instance, fine, medium, and coarse CaCO_3 particles reduced mud pH to over 11. In contrast, PP amounts of 10-15 ppb fine, 10 ppb medium, and 20-25 ppb coarse maintained pH within the intended value of 9-10 pH. More even and uniform interactions with mud can occur with fine PP particles that reduce sudden and abrupt changes in pH.

To summarize, when analyzing 28 formulations of mud, 15 were developed using PPs with different concentration and size. Of the 15 muds, only five muds (muds 15, 16, 20, 27, and 28) fell within the acceptable range for pH. The other mud formulations would need to add pH control additives. With respect to mud density, and pH, these five muds shown to be optimal.

4.4 Rheological Properties Analysis

The viscosity of drilling fluids is critical for wellbore stability and drilling efficiency. API RP 13B-1 says that a plastic viscosity between 3 to 15 cP is acceptable. If the viscosity is less than 3 cP, the mud does not have sufficient suspension ability for cuttings and could affect efficiency in hole cleaning, and also contribute to equipment wear and tear, and potential destabilization of the wellbore region. If the viscosity exceeds 15 cP, however, the hydraulic drag associated with excess viscosity will only inhibit cuttings removal, will increase drilling time and costs, and risk damaging the formation in the drilling process.

Therefore, it is necessary to keep viscosity within the recommended values for maintaining wellbore integrity, operational safety, and enabling efficient drilling practices.

Yield point is an important property of drilling mud, as it provides the initial resistance to flow of the mud, and how well the mud will suspend cuttings and solids while drilling. According to API RP 13B-1, the preferred range is 6–30 lb/100 ft². Once the yield point is below, or above this range, remedial measures will need to be taken. If the yield point is too low, the cuttings will settle in the borehole leading to poor hole cleaning, increased wear on the equipment, and possibly unstable wellbore conditions. If the yield point is too high, the mud will be excessively thick, increasing the pump pressure and efficiency of drilling operations will be reduced. A yield point that is properly controlled will transport cuttings efficiently, clean the hole effectively and maintain stable wellbore conditions, which is critical to the overall success and safety of the drilling operation.

Gel strength is an important rheological property of drilling mud, which is important in keeping the cuttings suspended in the mud when the circulation ceases. It is a measure of the mud's ability to create a gel-like structure that suspends solids. If the gel strength is low, cuttings can settle when the drilling stops and can lead to poor hole cleaning, wear on drilling equipment, and possible instability in the wellbore. On the other hand, if the gel strength is too high, the gel may be too viscous to allow for adequate circulation, which can increase pump pressures, increase overall drilling costs, and decrease efficiency. If the gel strength can remain within the defined limits, the mud will be able to suspend cuttings during interruptions in circulation, allow for optimal hole cleaning, ensure drilling efficiency, and minimize downtime and/or risks to underneath the surface drilling.

Reference mud had a plastic viscosity of 9 cP, a yield point of 22 lb/100 ft², an initial gel strength of 14 lb/100 ft², and a final gel strength of 27 lb/100 ft² as measured by the Model 900 viscometer (Table 4.8, Figure 4.7). The rheological properties of all other formulations (Table 3.5) were measured in a similar way, and the effects of fine, medium, and coarse LCM particle sizes are described in Tables 4.9-4.11 and illustrated in Figures 4.8-4.13.

Table 4.8 Rheological properties of the reference mud

Property	Value	Unit
Plastic viscosity	9	cP
Yield point	22	lb/100 ft ²
Initial Gel	14	lb/100 ft ²
Final Gel	27	lb/100 ft ²

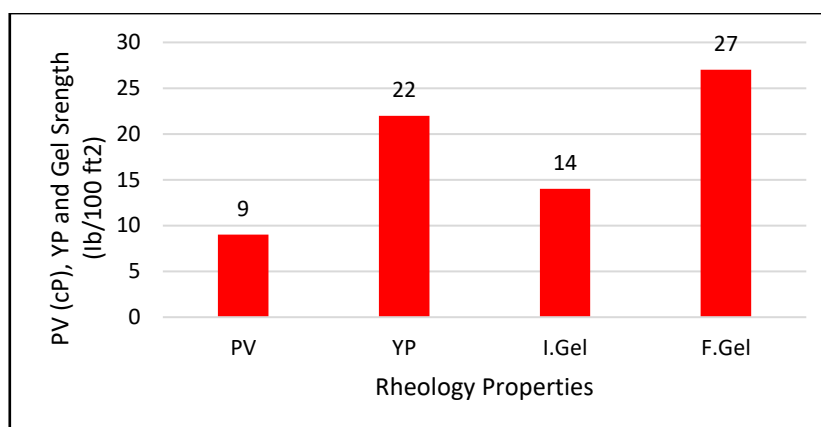


Figure 4.7 Rheological Properties of the Reference Mud

Table 4.9 Effect of Fine sized LCM on mud rheological properties

LCM Material	Concentration (ppb)	PV (cP)	YP (lb/100 ft²)	Initial Gel (lb/100 ft²)	Final Gel (lb/100 ft²)
Fine sized CaCO ₃	5	10.1	18	15	26
	10	13.5	19	18	41
	15	14.6	21	20	48
	20	15.7	23	21	52
	25	18.0	26	23	60
	30	20.2	28	27	67
Fine sized PP	5	9.0	22	5	19
	10	10.0	23	10	22
	15	13.5	24	17	35
	20	18.0	30	27	46

Table 4.10 Effect of Medium sized LCM on mud rheological properties

LCM Material	Concentration (ppb)	PV (cP)	YP (lb/100 ft²)	Initial Gel (lb/100 ft²)	Final Gel (lb/100 ft²)
Medium sized CaCO ₃	5	13.5	18	17	50
	10	15.7	29	33	60
	15	17.3	32	39	72
Medium sized PP	5	12.0	14	8	23
	10	13.5	23	9	26
	15	15.0	27	17	39
	20	22.0	48	30	50

Table 4.11 Effect of Coarse sized LCM on mud rheological properties

LCM Material	Concentration (ppb)	PV (cP)	YP (lb/100 ft ²)	Initial Gel (lb/100 ft ²)	Final Gel (lb/100 ft ²)
Coarse sized CaCO ₃	5	11.2	31	21	38
	10	11.3	42	26	43
	15	11.5	46	28	48
Coarse sized PP	5	7.0	2	5	12
	10	7.5	2	6	14
	15	8.0	3	7	19
	20	9.0	3	7	24
	25	12.0	3	7	28

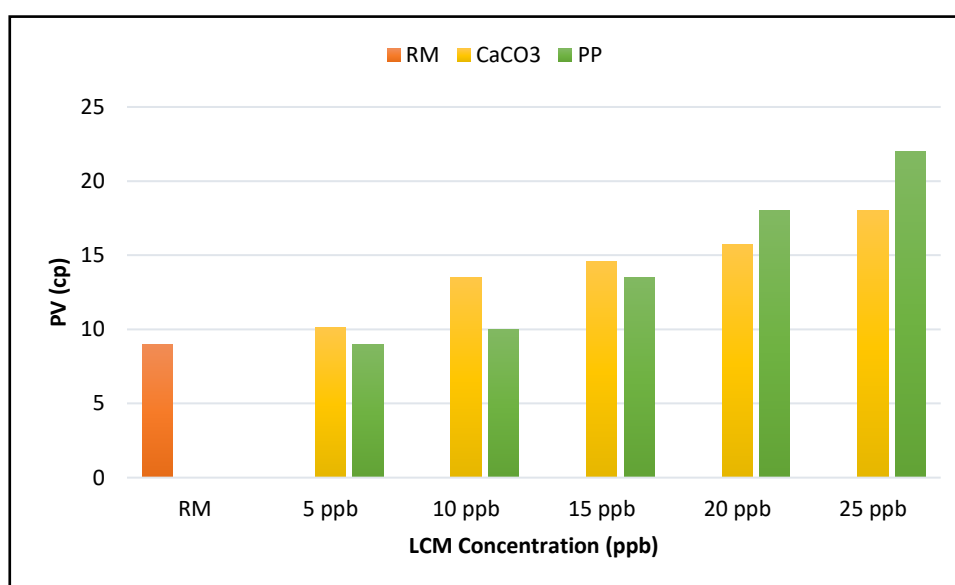


Figure 4.8 Plastic viscosity for fine sized LCMs

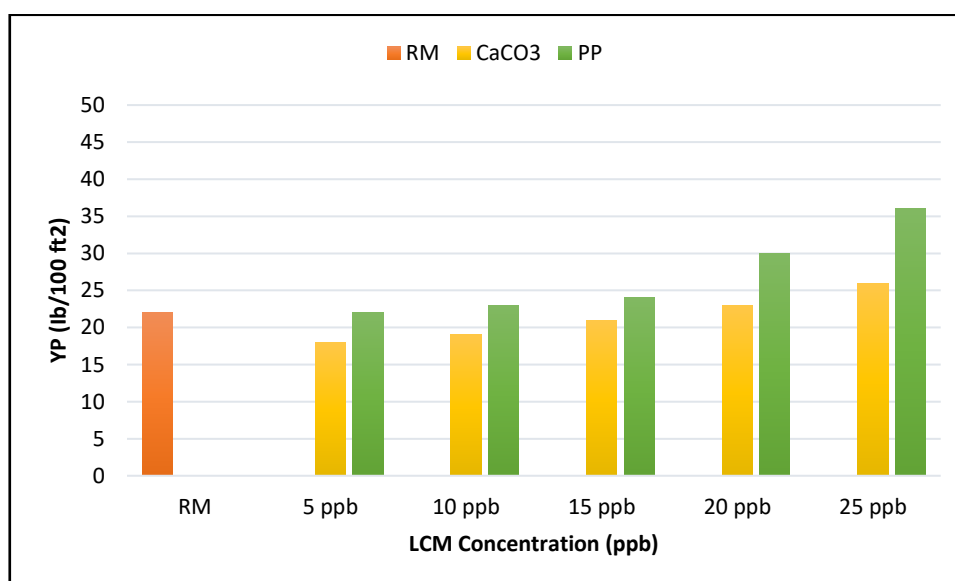


Figure 4.9 Yield Point for fine sized LCMs

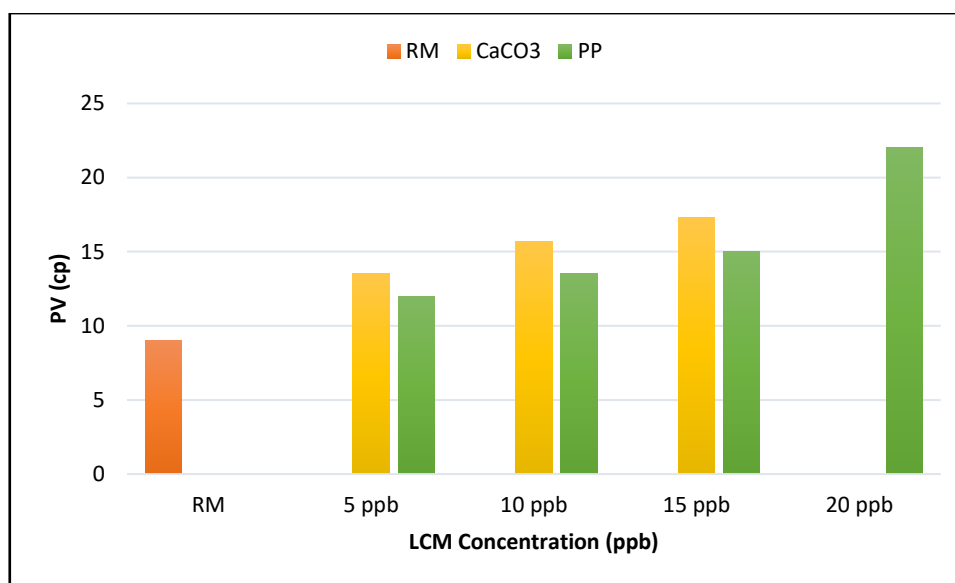


Figure 4.10 Plastic viscosity for medium sized LCMs

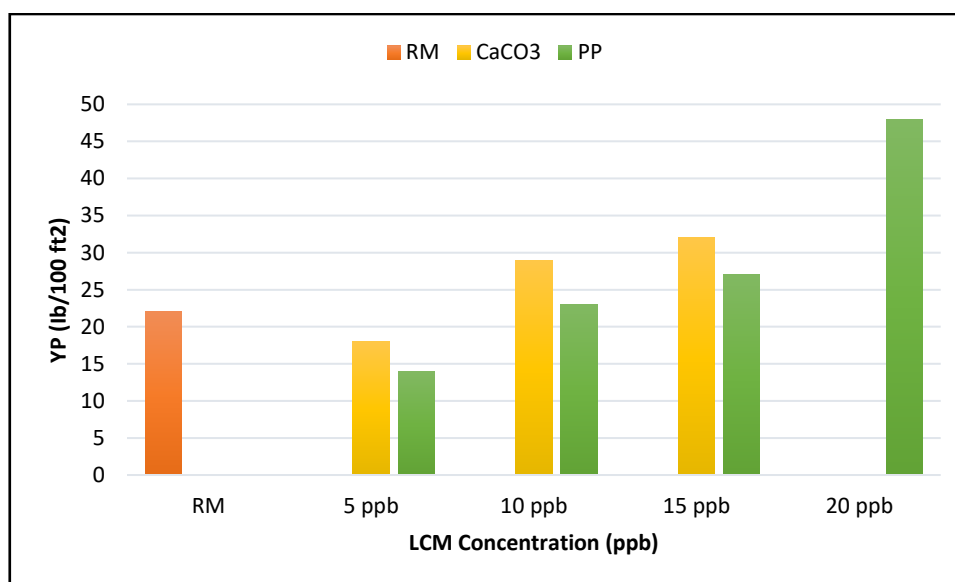


Figure 4.11 Yield point for medium sized LCMs

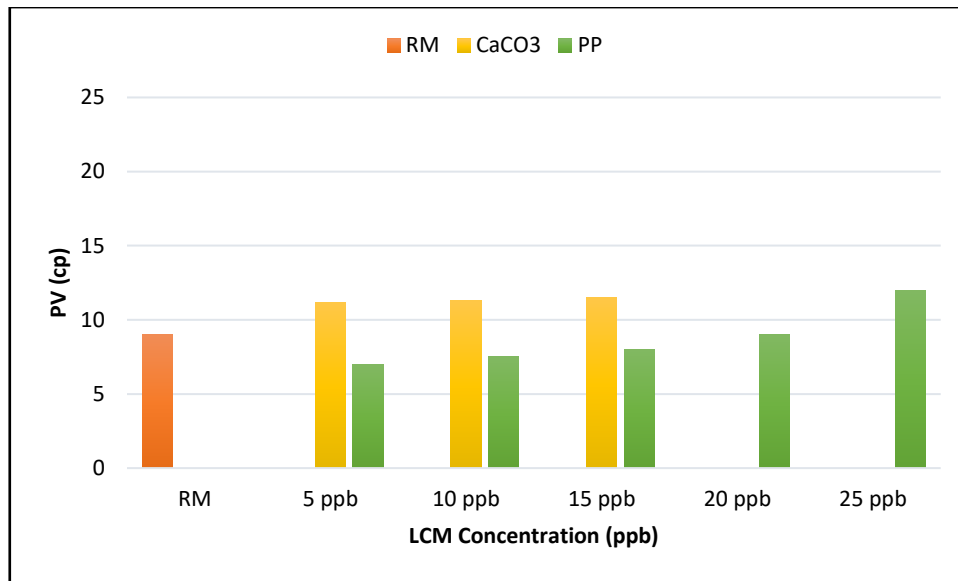


Figure 4.12 Plastic viscosity for coarse sized LCMs

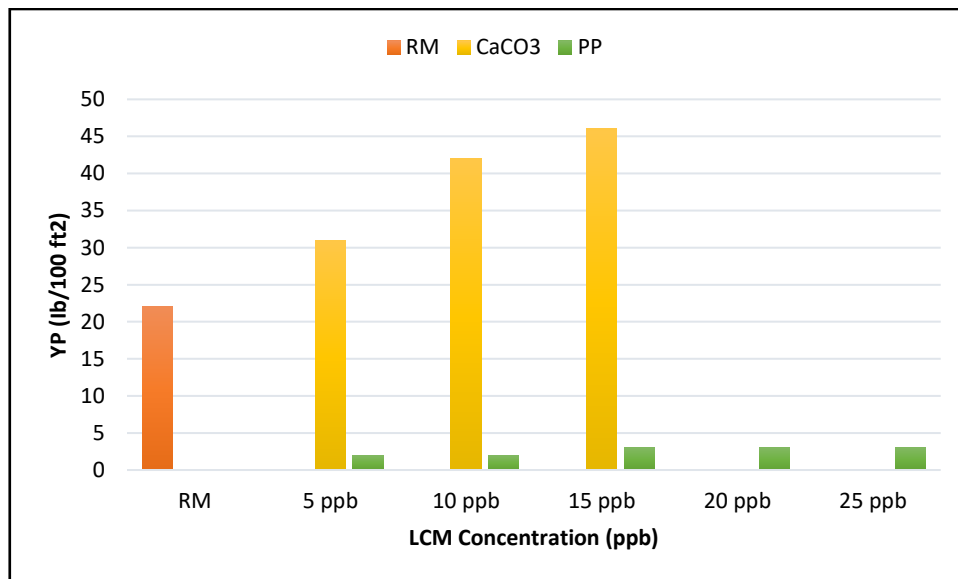


Figure 4.13 Yield point for coarse sized LCMs

As indicated in Table 4.18, the rheological properties of the reference LCM mud are consistent with the desired range of API RP 13B-1. The primary aim of this research is to determine the LCM type, particle size, and concentration that can sufficiently reduce the mud loss while preserving the properties listed above. Any changes that need to be made must be moderate, maintaining mud properties along the desired range of API RP 13B-1.

Upon analysis of Tables 4.9 to 4.11, the following observations are noted for each of the evaluated LCM materials:

Calcium Carbonate (CaCO₃):

Fine CaCO₃ LCM can be used up to 15 ppb for plastic viscosity, while medium CaCO₃ should be limited to 5 ppb. Coarse CaCO₃ has very little effect on viscosity, so concentrations may vary greatly. For yield point and gel strength, fine CaCO₃ can be used to 30 ppb, medium CaCO₃ should be limited to 10 ppb, and coarse CaCO₃ should be used no more than 5 ppb.

Pomegranate Peel (PP):

With regards to plastic viscosity fine and medium PP LCM can be used up to 15 ppb, while coarse PP has little impact on the reduction and can be used at a concentration higher than 25 ppb. As for gel strength and yield point fine PP even at 30 ppb is acceptable, medium PP should not go beyond 15 ppb, while coarse PP need to be avoided even at a 5-ppb concentration due to significant loss in these properties. Overall, in terms of plastic viscosity fine PP will have a small impact on this property while assisting in prevention of pumps experiencing excessive pressures, leading to high energy consumption.

Of the five tested mud formulations, the muds of 15, 16, and 20 displayed positive rheological properties. Of these muds, mud 16 performed best, containing Pomegranate Peel (PP) at a concentration of 15 ppb. Mud 16 had plastic viscosity, yield point, and gel strengths all within acceptable levels. Specifically, the mud 16 had a PV of 13.5 cP, YP level of 24 lb/100 ft², an initial gel strength of 17 lb/100 ft², and a final gel strength of 35 lb/100 ft², which is an excellent level of balance in the rheological properties.

In finality, of the total of 28 Pomegranate Peel (PP) mud formulations, 15 were chosen for a more in-depth study based upon the information gathered in the preliminary studies. Of these 15 formulations, six of the formulations had favorable rheological characteristics (i.e., plastic viscosity, yield point, and gel strength) (muds 14, 15, 16, 19, 20, and 21). Nevertheless, if the rheological properties, combined with mud density and pH are collectively contemplated, three formulations presented the optimal results (muds 15, 16, and 20). Therefore, given the pH, density, and rheological properties these three PP muds are the most effective and suitable formulations for drilling operations, balancing performance to maximize the drilling industry environmental sustainability, economic efficiency, and wellbore stability.

4.5 Solubility Measurement

The purpose of the solubility tests was to characterize the dissolution characteristics of fine-sized Pomegranate Peel (PP) powder in 15% HCl solution. For each test, 50 g of PP powder was added to a glass jar and 250 mL of 15% HCl solution was added. The solution was moderately acidic to promote dissolution while minimizing excessive reactions. The mixtures were stirred and allowed to react for 75 minutes, during which the mixtures were cautiously inspected for changes in effervescence or color as indicators of solubility. After the reaction time had elapsed, the solutions were then filtered to separate the undissolved residue. Data indicated approximately 96% of the PP had dissolved in the HCl solution. With the weight of the initial sample (50 g) and undissolved fraction (2 g), solubility was calculated using Equation (4.4). These results indicate a high solubility of PP in acidic conditions and the chemical characteristics and potential applications of the PP.

$$\text{Acid Solubility \%} = \left[1 - \frac{\text{final weight}}{\text{initial weight}} \right] \times 100 \quad \text{Eqn. (4.4)}$$

Table 4.12 PP Acid Solubility results

Acid Solubility	Pomegranate Peel
Initial weight (gm)	50
15% HCl volume (cc)	250
Time to dissolve (min.)	75
Residue left (gm)	2
Solubility (%)	96



Figure 4.14 PP in 15% HCl solution before the reaction time



Figure 4.15 PP in 15% HCl solution after the reaction time

4.6 Filtration Properties Analysis

This study aimed to examine the filtration properties of water-based drilling fluids as modified using both traditional and new loss control materials. The muds were modified with calcium carbonate (CaCO_3) and the biodegradable Pomegranate Peel (PP) to studies how they functioned. For the study the CaCO_3 LCMs were used at multiple particle sizes and concentrations to ensure that comparison was comprehensive in its evaluation of the filtration performance of the PP works. Notably, CaCO_3 does serve as a baseline standard LCM, suitable for use in the oilfields in Northern Iraq, and the results using PP may be compared to the more traditional CaCO_3 choice.

Filtration tests were performed in controlled conditions of 500 psi at 50 °C in a dynamic High-Pressure High-Temperature (HPHT) filter press. The findings are summarized in Tables 4.13 to 4.15 and presented graphically in Figures 4.16 to 4.18, indicating the filtration of the original base drilling fluid and the base mud with different sizes and concentrations of CaCO_3 and PP over a testing time of 30 minutes. The original mud had a filtration test volume of 32 mL in 30 minutes and a mud cake thickness of approximately 3 mm, which is the baseline to evaluate performance in the modified muds.

Table 4.13 Effect of Fine sized LCM on mud filtration properties

LCM Material	Concentration (ppb)	30 minutes Filtrate (ml.)	Mud Cake Thickness (mm)
Fine sized CaCO_3	5	27.5	4
	10	21.7	4.5
	15	17.7	4.5
	20	16.9	4.5
	25	17.7	4.8
	30	22.2	5
Fine sized PP	5	9	2.5
	10	7	2
	15	6	2
	20	5.3	2
	25	4.3	2

Table 4.14 Effect of Medium sized LCM on mud filtration properties

LCM Material	Concentration (ppb)	30 minutes Filtrate (ml.)	Mud Cake Thickness (mm)
Medium sized CaCO_3	5	17.1	3.8
	10	17.9	4
	15	18.3	3.5
Medium sized PP	5	10.9	2.5
	10	10.1	2.5
	15	9	2.5
	20	8.6	2.5
	25	7.9	2.5

Table 4.15 Effect of Coarse sized LCM on mud filtration properties

LCM Material	Concentration (ppb)	30 minutes Filtrate (ml.)	Mud Cake Thickness (mm)
Coarse sized CaCO_3	5	23	3
	10	23.3	4
	15	29.2	5
Coarse sized PP	5	11.8	2.5
	10	11.6	2.5
	15	10.8	2.5
	20	9.4	2.5
	25	8.9	2.5

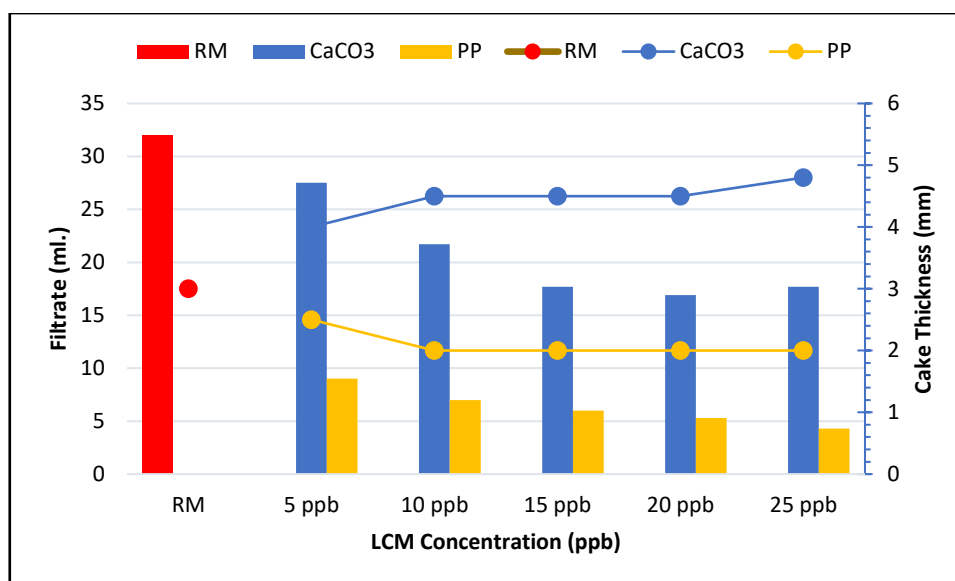


Figure 4.16 Fine sized LCM vs. mud filtration and mud cake

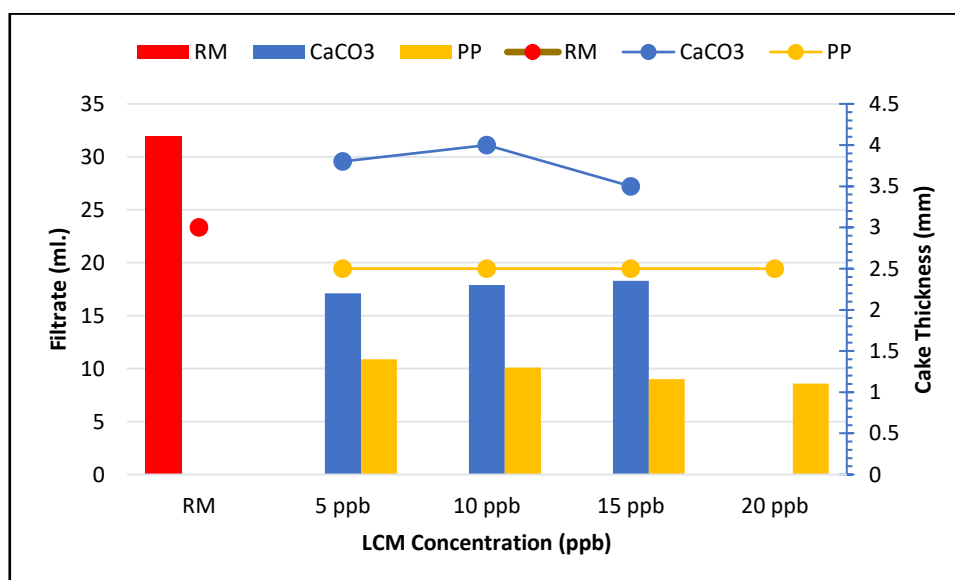


Figure 4.17 Medium sized LCM vs. mud filtration and mud cake

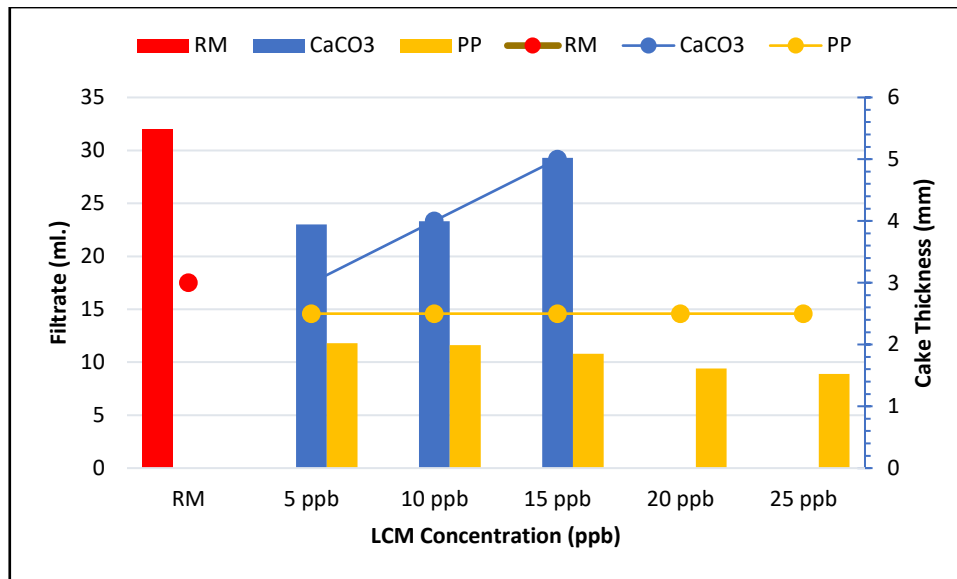


Figure 4.18 Coarse sized LCM vs. mud filtration and mud cake

The filtration property results show in the displayed tables and figures, by integrating different particle sizes and concentrations of Calcium Carbonate (CaCO_3) and Pomegranate Peel (PP), there has been a clearly demonstrated reduction in filtrate volumes. However, the use of CaCO_3 LCM led to an unacceptable increase in mud cake thickness for all tested sizes and concentrations, unequivocally indicating that very thick mud cakes can limit borehole diameter, resulting in the risk of differential sticking and/or isolation of the drill string, which is a significant drawback of traditional CaCO_3 as a loss control material.

Relative to CaCO_3 , all sizes and concentrations of Pomegranate Peel (PP) achieved reductions in mud cake thickness. As a lost circulation material, this mud cake thickness reduction associated with PP is a significant benefit, suggesting that it could be used for wellbore conditions where it is essential to maintain the borehole diameter in the acceptable range while drilling.

Moreover, while all materials resulted in reductions in filtrate rate, it was clear that the size of the particles and concentration of each type differing filtrate rate reductions. This data reinforces what previous studies have indicated about the ability to control lost circulation is reliant in large part to the particle size and concentration. Fine-sized CaCO_3 achieved the largest reduction in filtrate rate to 20 ppb, with resulting 47% reduction based on the filtrate rate for only water. Any increase beyond 20 ppb the filtrate rate increased back toward the filter rate of no additive, suggesting an optimal concentration of fine-sized CaCO_3 . The same finding occurred with coarse and medium-sized CaCO_3 , concentrations greater than 5 ppb, were detrimental to lost circulation control as resulting filtrate rates increased. This

information emphasizes the necessity of selective the proper size of required particles and amount in controlling mud losses during drilling operations.

Results demonstrated a clear inverse relationship between Pomegranate Peel (PP) concentration and filtrate rate as higher PP concentrations reduced fluid loss by creating a dense barrier of low permeability. The selection of the optimal PP concentration requires balancing several factors including mud density, pH, rheology, cake thickness, solid content, and cost in order to control lost circulation while maintaining the overall performance of the drilling fluid.

Filtrate rates decreased the most with Pomegranate Peel (PP), varying by particle size: 86% reduction at 25 ppb of fine PP, 75% reduction at 20 ppb of medium PP, and 72% reduction at coarse PP. In terms of fluid loss, 25 ppb of fine PP (mud no. 18) resulted in the highest reduction. However, its pH of 7.7 made it less desirable. After considering all factors including pH, rheology, and mud performance, the best configuration was determined to be 15 ppb of fine PP.

In conclusion, if we only focus on filtration control then muds no. 18, 17, 16, 15, and 14 ranks from the best to the worse in order. However, in the optimal choice of an LCM, the filtration considerations are not the only factors to consider. Just 15, 16, and 20 muds met the needs and required specifications for density, pH, and rheology. Thus, even though muds no. 18, 17, and 14 have better filtration, their lack of additional properties will ultimately not be considered. Consequently, mud no. 16 is the best selection as it provides filtration control at the same time, satisfies all the required properties for mud performance - including density, pH, rheology, and mud cake properties.

To sum up, mud composition 16, consisting of 15 ppb of fine-sized Pomegranate Peel (PP), is the best-performing formulation of the twenty-eight mud compositions tested through careful procedures. The mud composition has a density of 8.5 ppg, pH of 9.5, plastic viscosity of 13.5 cP, yield point of 24 lb/100 ft², initial gel strength of 17 lb/100 ft², and final gel strength of 35 lb/100 ft². In addition, its chemical performance also performed well, dissolving to 96% in a 15% HCl solution, an 81% reduction in the filtrate rate, and forming a thin cake of mud at 2 mm, suggesting that this mud formulation can perform well in rheological stability and lost circulation control.

4.7 HSE and Economic Worth Analysis

Lost circulation is a common problem in the oil and gas exploration and production business when drilling that can have significant costs associated with it. Historically, this has been handled using chemical-based Lost Circulation Materials (LCMs). Today, with growing awareness of environmental and economic challenges associated with using synthetic additives, there is a push for sustainable and green alternatives. In this order, natural and biodegradable materials, particularly Pomegranate Peel (PP) powders, are viewed as potential alternative materials. These materials can achieve comparable results to a conventional industrial LCM, all while limiting environmental damage and having the potential to decrease project costs, making them a more favorable alternative for modern drilling applications.

4.7.1 Health and Safety Benefits

An important benefit to using Pomegranate Peel (PP) as a Lost Circulation Material (LCM) is an improvement in health and safety. Chemical LCMs usually contain toxic materials, which create a risk to people and the environment. PP, being non-toxic, reduces the hazard of exposure to workers. In addition, in the case of chemical LCMs, the fine particles risk harm to the respiratory system and create other health issues for drill crew. Using plant-based powders like PP, which are also biodegradable, eliminates this risk and creates a safer environment for inhalation. In turn, this reduces exposure from handling, storing, and transporting hazardous chemicals and supports a safe and environmentally friendly drilling operation.

4.7.2 Environmental Advantages

Pomegranate Peel (PP) presents significant environmental advantages as a Lost Circulation Material. Given that Pomegranate Peel is biodegradable, whatever material is lost into the formation during drilling is unlikely to pollute the environment when compared to traditional chemical LCMs, which may persist indefinitely in the environment. In addition, the integration of agricultural waste like PP provides a dual benefit, reducing the amount of waste associated with resource consumption when developing in accordance with a circular economy, in conjunction with being a sustainable source with a lower carbon footprint, as the incorporation of natural PP-based raw materials requires far less energy than synthetic chemical LCMs. Therefore PP serves an environmentally responsible alleviation of reduced circulation and is aligned with advanced drilling practices.

4.7.3 Economic Benefits

Economically speaking, there are a lot of advantages to using Pomegranate Peel (PP) as a Lost Circulation Material. Natively sourced materials, like PP, are almost always cheaper to grow and produce than the synthetic chemical LCM options. Furthermore, wages and costs within the economy are saved further if PP is locally sourced. With an increasing understanding and interest of the public and companies to have environmentally friendly options in oil and gas, there is a possibility for jobs around PP being developed and commercialized. In addition the agricultural economy community would have from the PP, this sustainable type of farming and harvesting would also be able to provide a continuous and reliable supply to PP; eliminating the price variables we may see with chemical LCMs. Therefore, use of PP as an LCM would decrease costs for the operation, while also working towards our shared needs and wants for regional economic sustainability.

5 Conclusions and Recommendations

5.1 Conclusions

- The current research explored the usage of natural and biodegradable Lost Circulation Materials (LCMs) in drilling in the oil and gas drilling industry by utilizing a variety of materials that included rice, date tree, banana, apple, walnut, grass, agarwood and durian rind.
- The study proceeded through a number of laboratory experiments using approximately six different materials and six specialized pieces of apparatus to study and observe the behavior of drilling fluids.
- Pomegranate Peels (PP) were collected specifically processed and prepared and used in the experiments.
- There was a total of 28 different formulations of the drilling muds that were developed during the experimental phase, and these were categorized into other groups that included Reference Mud (RM), Calcium Carbonate (CaCO_3) LCM Additive Mud and Pomegranate Peel (PP) Additive Mud.
- Each mud was evaluated on density, pH and rheological properties; each test was done in triplicate before moving ahead with the next phase, which included: stability, filtration volume, and the thickness of mud cake.
- After completing a total of 28 mud formulations, three muds (muds 15, 16, and 20) met all established guidelines for mud density, pH and rheological parameters.
- For filtration control, the muds identified with the best results were muds 18, 17, 16, 15 & 14 with significant fluctuations in performance across samples.
- As an overall parameter consideration mud number 16 was the most appropriate mix as it met parameters for desired density, pH and rheological properties, and formation of mud cake.
- Mud number 16 consisted of 15 pounds per barrel (ppb) of finely sized Pomegranate Peel (PP) and was determined to be the most appropriate opportunity in terms of address lost circulating materials on a drilling operation.
- Mud number 16 data highlighted outstanding performance on all levels, which included significant reductions of filtration volume, a thin mud cake, and was some of the data obtained in order: 8.5 ppg, 9.5 pH, 13.5 cP plastic viscosity, and an 81% reduction in filtration volume from water.

- The study identified multiple advantages of using Pomegranate Peel in LCM formulation, in terms of the health and safety aspect, environmental improvement, and economic benefits.
- In picture, the use of natural materials is in line with the oil and gas industry's goal of sustainability, and contribute to developing a more sustainable alternative to conventional materials in drilling while protecting humans and the environment.

5.2 Recommendations

The recommendations below are suggested based on the findings of this research:

- **Incorporating Natural and Biodegradable LCMs into Drilling:** Drilling companies and operators should strongly consider the potential advantage of using the best mud formulation discovered in this study (i.e., mud No. 16) as part of their strategies in areas of northern Iraq that are prone to lost circulation. The use of materials like Pomegranate Peel (PP) has shown not only a significant advantage in alleviating lost circulation but has also provided meaningful benefits to the environment. The world is moving toward a more sustainable and responsible oil and gas industry, and the use of these environmentally friendly LCMs represents a part of that shift.
- **Laboratory Testing and Validation:** While the lab tests indicate potential, testing and validating once again in the field and real conditions is needed. The research community and drilling companies should encourage collaboration to carry out field tests on natural LCMs under real-world drilling conditions in order to help validate performance. Data accepted from these field tests will help to produce a more realistic assessment of the performance and reliability of these materials in practicing rig conditions.
- **Rig System Construction:** It is strongly suggested that a rig comes equipped with a full-scale core holder that demonstrates its ability to use larger core samples for testing, instead of using filter paper tests only, to generate data that related more to real field conditions.
- **Investing in Nanomaterial Research:** Continued investment in nanomaterial investigations is warranted, including in LCMs, to promote the ability to build natural LCMs that are more efficient and adaptable. These materials may ultimately provide solutions to resolve issues associated with lost circulation, particularly in high-pressure and temperature (HPHT) drilling conditions.

- **Ongoing Environmental Monitoring:** As the industry continues to adopt environmentally friendly LCMs, a continued commitment to adequate measure should be provided to obtain and track their environmental impact. This may include reviews of degradation, long-term impacts to ecosystem, and the relationship of biodegradability with formations. Left as unaddressed may receive scrutiny from environmental authorities and lead to regulatory measures.
- **Economic Analysis:** Robust economic analysis should be conducted to assess the overall economic feasibility of using natural and biodegradable LCMs, including the costs compared to traditional chemical LCMs and savings as a result of improved health, safety, and overall ecological and environmentally friendly reporting. This will allow decision makers to identify a scope of the economic front facing switching to sustainable LCMs.

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Department of Petroleum Engineering



"Evaluation of source rock potentiality and Kerogen types: Case study from Mesozoic shales, N. Iraq"

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Dedication

This work is dedicated to our families, whose continuous support, patience, and encouragement have been the foundation of my academic journey. Their belief in my abilities gave me the strength to pursue this research and complete it despite the challenges faced throughout the study period. I also dedicate this work to every teacher and mentor who inspired me to value science, research, and perseverance in the pursuit of knowledge.

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Glossary of Terms

The following terms are used throughout this study to explain the organic geochemical characteristics and petroleum source rock evaluation of the Naokelekan Formation. These definitions are included to clarify the scientific terminology and provide a consistent understanding of the main concepts discussed in this research.

Source Rock: A sedimentary rock that contains sufficient organic matter capable of generating hydrocarbons when subjected to suitable burial and thermal conditions.

Kerogen: The insoluble organic matter preserved within sedimentary rocks that serves as the precursor material for oil and gas generation during thermal maturation.

Rock-Eval Pyrolysis: A laboratory technique used to evaluate the quantity, quality, and thermal maturity of organic matter in source rocks by heating the samples under controlled conditions.

Total Organic Carbon (TOC): The percentage of organic carbon present in a rock sample, commonly used as an indicator of organic richness.

S1: The amount of free hydrocarbons already present in the rock sample before cracking of kerogen during pyrolysis.

S2: The quantity of hydrocarbons generated from the thermal cracking of kerogen during pyrolysis, representing the remaining generative potential of the rock.

S3: The amount of carbon dioxide released during pyrolysis, reflecting the oxygen-bearing compounds present in the organic matter.

Tmax: The temperature at which the maximum release of hydrocarbons occurs during the S2 peak, commonly used as an indicator of thermal maturity.

Hydrogen Index (HI): A derived parameter calculated from S2 and TOC, used to determine kerogen type and hydrocarbon potential.

Oxygen Index (OI): A derived parameter calculated from S3 and TOC, used to evaluate the oxygen content of the organic matter.

Production Index (PI): A ratio expressing the relationship between free hydrocarbons and total hydrocarbon potential, commonly used as an additional maturity indicator.

Weathering: The physical and chemical alteration of rock materials at the Earth's surface, often leading to oxidation and deterioration of original geochemical characteristics.

Oxidation: A chemical process in which organic matter reacts with oxygen, resulting in hydrogen loss, oxygen gain, and distortion of source rock geochemical parameters.

List of Abbreviations

TOC — Total Organic Carbon

HI — Hydrogen Index

OI — Oxygen Index

PI — Production Index

S1 — Free Hydrocarbons

S2 — Remaining Hydrocarbon Generative Potential

S3 — Carbon Dioxide Released During Pyrolysis

Tmax — Temperature of Maximum Hydrocarbon Generation

HC — Hydrocarbon

mg HC/g rock — milligrams of hydrocarbon per gram of rock

mg CO₂/g rock — milligrams of carbon dioxide per gram of rock

wt% — weight percent

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Abstract

This study surveys the organic geochemical properties and hydrocarbon generative activity of the Middle-Upper Jurassic Naokelekan Formation in the Kurdistan Region of Iraq. The Rock-Eval pyrolysis and Total Organic Carbon (TOC) measurements were evaluated at two surface outcrops (Halabja and Barzinja sections) and compared to its unweathered subsurface baseline at the Taq Taq-1 well. The resulting analyses show marked differences in geochemical characteristics caused by aggressive surface oxidation. The weathered surface samples are in a "false negative" profile with low generative production (close to 0 S₂ peaks), an artificially induced move towards inert Type IV kerogen from hydrogen stripping, and oxygen injection, and non-standard, false high T_{max} values.

However, the subsurface data shows the true economic potential of the formation. These unweathered samples show very good organic richness, with an average TOC of 2.16 wt%, and a very high amount of generative capacity (mean S₂ value of 8.9 mg HC/g rock). The preserved organic matter is definitively high quality, oil-rich Type II kerogen (average HI of 347.4 mg HC/g TOC), found in the early portion of the oil generation window.

Summing up, Naokelekan Formation is one of the most effective and the most abundant oil-source rock in the regional petroleum system. This work underscores the great limitation of relying on extracted weathered outcrop for source rock estimation independently through lack of subsurface calibration.

1. Introduction

1.1 Overview of Iraq's Geology

The geological history of Iraq is associated with a diverse tectonic and sedimentary history that is influenced by the alignment of the country with the Arabian Plate. Iraq's Mesozoic sequences were laid down along the eastern passive margin of the Arabian craton. This tectonic boundary had wide tectonic movements, with a rift as part of the Permian and Triassic periods, drift as part of the Jurassic and Early Cretaceous and later as part of the suture transition from both the Late Cretaceous and Early Tertiary.

This process of dynamic tectonic evolution created immense sedimentary basins. As an example, the exposed Jurassic formations in the Zagros foreland basin of Iraq can be found in isolated locations in the eroded cores and limbs of anticlines found in the High Folded, Imbricated and Thrust Zones of Northern Iraq. As a result, the Upper Jurassic–Lower Cretaceous succession has become the most important and efficient petroleum system in Iraq and includes a large number of source rocks that have enabled the region's hydrocarbon accumulations.

1.2 Fundamentals of Petroleum Source Rocks

A petroleum source rock is a fine-grained sedimentary rock with enough organic matter to yield and expel commercial amounts of hydrocarbons at sufficient thermal load, in general. Assessment of these rocks is the cornerstone of petroleum exploration. The sedimentary interval is a good source rock, but for it to be effective as a source rock, it needs three factors: high organic richness (quantity), oil- or gas-prone organic matter (quality), and an adequate level of thermal maturation.

Shales and argillaceous limestones, for example, are the most common source rocks because their relatively low-energy and anoxic depositional settings are perfect for the preservation of organic matter before burial diagenesis.

1.3 Kerogen Types and Hydrocarbon Potential

The insoluble portion of the organic matter preserved within a source rock is known as kerogen. The quality and hydrocarbon-generative potential of a source rock depend primarily on the type of kerogen it contains, which is structurally defined by its hydrogen and oxygen atomic composition. Geochemically, kerogen is classified into four main categories:

- Type I: Highly oil-prone, typically derived from algal remains in lacustrine environments.
- Type II: Oil-prone, usually originating from marine phytoplankton and zooplankton, and is the most common kerogen type in prolific marine source rocks.
- Type III: Gas-prone, derived mainly from terrestrial higher plant debris.
- Type IV: Inert or "dead" carbon, which has little to no generative potential due to severe oxidation or thermal degradation.

1.4 Thermal Maturation and the Oil Window

The source rock with the ability to produce hydrocarbons now also needs to be buried down deep enough to experience substantial heat and pressure over a geological time scale, which is called thermal maturation. The organic matter undergoes three phase transformations: immature (no extensive generation), mature (oil window; liquid hydrocarbons and wet gas are formed), and post-mature (dry gas window where only methane is generated or the rock becomes entirely depleted). Accurately detecting thermal maturity of a formation is important to predict the generation of oil, gas, or nothing at all in a basin.

1.5 Geological Setting of the Naokelekan Formation

During the Late Jurassic period, a foreland basin developed close to the craton's margin, which is when the Naokelekan and Barsarin formations were deposited. The Upper Jurassic Naokelekan Formation is recognized as one of the most important hydrocarbon source rocks in northern Iraq. Lithologically, it is characterized by bituminous and dolomitic limestone intercalated with thin, black, calcareous shale. Organic-rich algal mats present within these strata confirm that the formation was deposited under euxinic (anoxic) conditions within a shallow marine, subtidal to supratidal depositional environment. Geographically and tectonically, the outcrops of the Naokelekan Formation are well exposed in several areas, including the Barzinja section, located in the High Folded Zone, and the Halabja section, situated in the Imbricated Zone.

1.6 Problem Statement

To assess generation and thermal maturity of potential source rocks, petroleum geochemists often use programmed pyrolysis, in particular using the Rock-Eval method. The Rock-Eval pyrolysis is used to quickly determine the petroleum-generative potential, quantity, type, and thermal maturity of rocks based on the parameters (free hydrocarbons (S1), pyrolyzed kerogen hydrocarbons (S2), generated carbon dioxide (S3), and the temperature of maximum hydrocarbon generation Tmax) derived from their geometries. One of the most common challenges in source rock estimation involves source rock evaluation from outcrop samples. Such organic matter is susceptible to oxidation during transport, deposition and post-deposition period or surface exposure.

In such cases, the erosion and weathering of outcrop samples removes hydrogen and adds oxygen to kerogen, resulting in a dramatic change of critical geochemical parameters (such as Hydrogen Index (HI) and Oxygen Index (OI)). Thus, outcrop samples are typically characterized by extreme depletion of S1 and S2 peaks and abnormally high S3 values due to weathering. Such surface alteration means that potentially rich, oil-prone organic matter is often lumped together with inert, post-mature Type IV kerogen. Deriving generative models exclusively from heavily degraded outcrops—specifically the Halabja and Barzinja exposures—without rigorous subsurface calibration inevitably corrupts analytical frameworks. Ultimately, this methodological trap misleads exploration teams, compelling them to drastically undervalue the authentic hydrocarbon endowment intrinsic to the Naokelekan Formation.

1.7 Research Objectives

Targeting the Mesozoic Shales of Northern Iraq, this research seeks to rigorously quantify the authentic source potential and kerogen typologies intrinsic to the Naokelekan Formation. To

systematically circumvent the degradational artifacts introduced by subaerial exposure, we deploy a comparative geochemical framework driven by the following core directives:

1. **Baseline Geochemical Profiling:** Utilizing Rock-Eval pyrolysis datasets, this initial phase maps the formation's foundational parameters—specifically isolating Total Organic Carbon (TOC) concentrations, structural kerogen classification, and baseline thermal maturity.
2. **Cross-Zonal Correlation:** A diagnostic contrast is established by juxtaposing heavily degraded outcrop strata from the Imbricated (Halabja) and High Folded (Barzinja) regions against pristine, unweathered subsurface cores recovered from the Taq Taq-1 well.
3. **Quantifying Oxidative Distortion:** This segment isolates the specific chemical mechanisms through which meteoric weathering corrupts pyrolytic signatures. It tracks how prolonged environmental exposure triggers a deceptive collapse in the Hydrogen Index (HI) alongside an anomalous inflation of maturity thresholds (Tmax), phenomena that collectively force a mathematically false "Type IV" (inert) kerogen diagnosis.
4. **Recalibrating Generative Capacity:** Anchoring the final assessment strictly on unadulterated subsurface metrics, this research dismantles the prevailing paradigm of surface-level depletion. Ultimately, the compiled evidence confirms the unit's authentic viability as a highly prolific Type II/III hydrocarbon source.

2. Literature Review and Methodology

2.1 Introduction to Source Rock Evaluation

At their core, source rocks are fine-grained sedimentary units defined by a single critical characteristic: they contain sufficient organic matter, or kerogen, to generate and subsequently expel hydrocarbons when subjected to adequate thermal stress. Evaluating this latent potential dictates the entire trajectory of petroleum exploration. Before a sedimentary basin can be considered viable, geoscientists must absolutely confirm its baseline capacity to produce oil or gas.

This evaluation strips the source rock down to three fundamental geochemical pillars. The analysis must first quantify the absolute abundance of the organic material (richness) before identifying its specific structural lineage (kerogen type). Concurrently, it requires measuring the thermal maturity to gauge the exact degree of geologic heating the strata have endured over time. Only by integrating these three distinct metrics can researchers reliably forecast the expelled hydrocarbon volume and determine its definitive phase as either oil or gas.

2.2 Principles of Rock-Eval Pyrolysis

Circumventing the prohibitive costs and prolonged timelines inherent to traditional solvent-based kerogen isolation and elemental analysis, Rock-Eval programmed pyrolysis remains the definitive industrial standard. By operating directly on pulverized whole-rock samples, this technique rapidly extracts critical geochemical metrics, fundamentally streamlining source rock evaluation frameworks. The analytical procedure of Peters (1986) has been based on the method of heating a small and solid rock (about 100 mg) in a high temperature with helium in the inert phase. The apparatus has a Flame Ionization Detector (FID) for sense of produced organics, and a Thermal Conductivity Detector (TCD) for measuring emissions of CO₂. The apparatus collects four basic measurements during the programmed heating procedure:

- **S1 Peak (Free hydrocarbons):** The peak represents the amount of liberated organic compounds (bitumen) that are thermally reduced to a certain degree from the rock sample undergoing an isothermal heating process at 300°C, expressed in milligrams of hydrocarbons per gram for each rock material (mg HC/g rock).
- **S2 Peak (Generated Hydrocarbons):** Once the temperature rises from 300°C up to 550°C, the insoluble organic matter (kerogen) undergoes pyrolytic degradation (crack). The S2 peak is the amount of hydrocarbons produced at this stage, showing the remaining generative potential of the rock and expressed in mg HC/g rock too.
- **S3 Peak (Carbon Dioxide):** This is a measure of the amount of carbon dioxide produced from the pyrolysis of the organic matter up to 390°C detected by the TCD and expressed in mg CO₂/g rock.
- **Tmax (Temperature of Maximum Generation):** The exact oven temperature (°C) of a hydrocarbon's max-generation process at which the most generation of fuel occurs, at the top of the S2 peak. Tmax is a good reference on the thermal maturity of the organic matter. When combined with these direct readings along TOC of sample, a number of essential geochemical indices are obtained to classify the kerogen type and determine its maturity of composition:
- **Hydrogen Index (HI):** Assumed as $(S2 / TOC) \times 100$ and expressed in mg HC/g TOC. The HI is directly related to the atomic H/C ratio, and is the main parameter used to classify the polymer of origin which is hydrocarbon generating such as oil-generative type II and gas-generative type III.
- **Oxygen Index (OI):** $(S3 / TOC) \times 100$, mg CO₂/g TOC. OI is assigned the reference atomic O/C

ratio, is used with HI in a modified Van Krevelen diagram, and can further describe the type of kerogen. • Production Index (PI), defined as the value $S1 / (S1 + S2)$. As the source rock matures and kerogen becomes free hydrocarbons, the PI starts to rise over time, therefore using this is well suited for estimating thermal maturity as well as the location of migrating hydrocarbons.

2.3 The Impact of Weathering and Oxidation on Outcrop Samples

Although Rock-Eval pyrolysis is a powerful method for analyzing the subsurface, it poses considerable geochemical obstacles to the use of this method on surface outcrop samples. The organic matter that is exposed at the surface is very sensitive to alteration at the point of exhumation, transport, and surface weathering. The highest impact is on the kerogen oxidation due to this surface exposure. Peters (1986) says that oxidation chemically changes the kerogen structure by stripping off hydrogen atoms and simultaneously adding oxygen. The damage from this chemical breakdown is both direct and predictable in terms of pyrograms in pyrolysis:

- * Depletion of hydrocarbon peaks: Not only is the concentration of free hydrocarbons diminished in S1 peaks but so is S2 peaks as well.
- * Elevation of carbon dioxide generation level: The S3 peak becomes unusually high since greater oxygen content inside the transformed kerogen structure will result.
- * Misclassification of Kerogen: The Hydrogen Index (HI) depends mathematically on S2 and the Oxygen Index (OI) on S3 so weathered samples will produce an inherently unnatural plot with low HI and high OI values. As a result, rich and oil-rich source rock (Type II or III) can easily be misclassified as a depleted and inert Type IV kerogen.
- * Distortion of Thermal Maturity (Tmax): Highly oxidized or Type IV kerogens are often in an erratic or artificially high Tmax, meaning they appear to be in a post-mature state, or lack a visible peak in S2 at all.

As a result, using the surface samples alone, without accounting for these weathering effects, may result in an extreme underestimation of the actual hydrocarbon potential of a sedimentary basin.

2.4 Methodology

To accurately evaluate the source rock potentiality of the Naokelekan Formation and circumvent the limitations imposed by surface weathering, this study employs a comparative analytical methodology.

2.4.1 Study Areas and Sampling

Two different structural zones in northeastern Iraq were pursued for fieldwork and sample collection. The Naokelekan Formation surface outcrop sections were systematically sampled from the Halabja section of the Imbricated Zone, and the Barzinja section of the High Folded Zone. 37 samples were obtained from surface outcrops for wide variation of inorganic and organic geochemical investigations at the preliminary stage. But, for the sole evaluation of organic source rock through programmed pyrolysis, we have sampled a representative of those samples. The data of Rock-Eval pyrolysis in this study is found to include:

- 10 surface samples were obtained using the Halabja section.

- 8 surface samples from the Barzinja section.

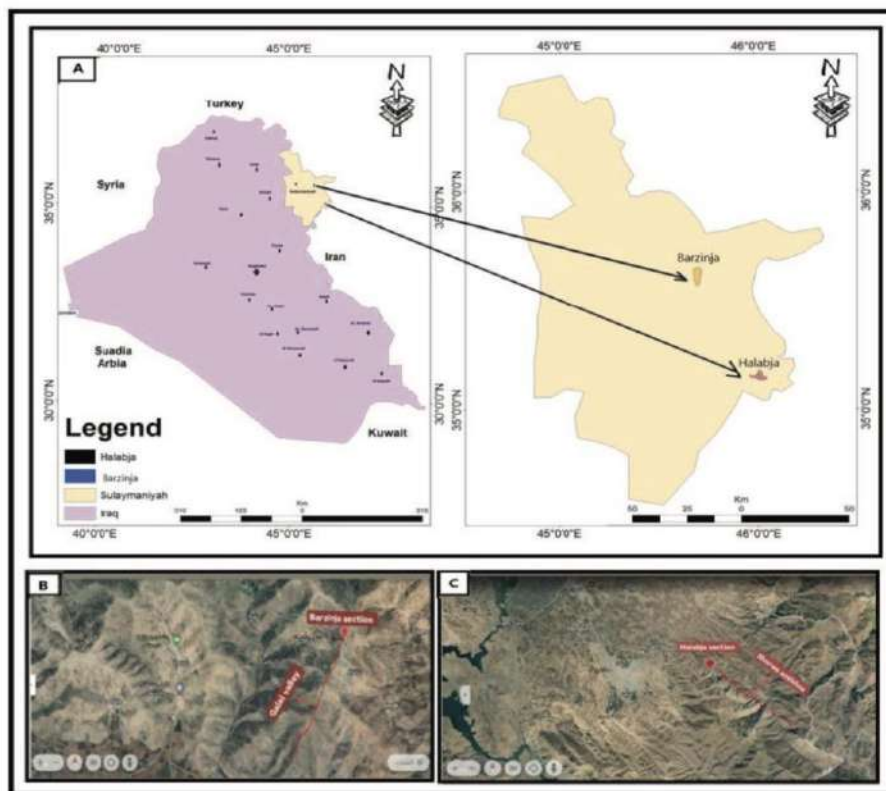


Fig. 1. A. Location map of the study area, B. and C. Aerial photos of the Halabja and Barzinja sections, respectively

Based on the aforementioned results, 18 of these weathered surface samples are plotted to compare the properties against a data set of 10 subsurface core samples from the Taq Taq-1 well to provide us with a reliable baseline to estimate true potential of the Naokelekan Formation without weathering that is, the unweathered core. In order to analyze the kerogen type, quality, and thermal maturity, the generated dataset is geochemically generated and plotted against standard geochemical models.

Modified Van Krevelen Diagrams (HI vs. OI) — for the purpose of identifying the main kerogen type and showing the oxidation pathway.

Generative Potential Plots (TOC vs. S₂) To investigate the organic matter efficiency and hydrocarbon yield regardless of the oxygen impact.

Projecting the datasets onto T max versus HI and Tmax} versus PI cross-plots accurately delineates the organic matter's true thermal evolution, thereby isolating the artificial maturity shifts driven by surface oxidation.

3. Results

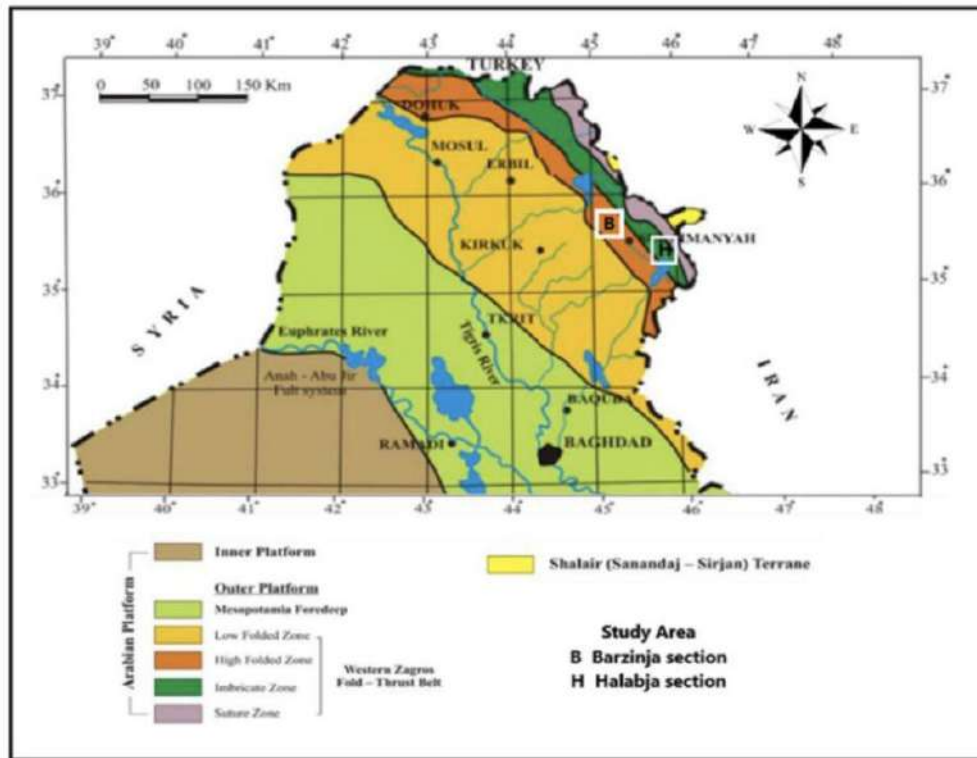


Fig. 2. The location of the sections under study on a tectonic division map of Iraq after(Fouad, 2015)

3.1 Introduction

The main organic geochemical contents obtained from the analyzed samples of the Naokelekan Formation are given in this chapter. The overall aim of this chapter is to systematically display the

quantitative results obtained using Total Organic Carbon (TOC) analysis and programmed Rock-Eval pyrolysis. The data is structured in three parts for a good comparison of our obtained results: weathered surface samples from Halabja, weathered surface samples from Barzinja, and unweathered subsurface reference samples from Taq Taq-1 well. It is important to note that this chapter strictly reports the measured and calculated parameters (e.g., S1, S2, S3, Tmax, HI, OI, and PI); the detailed interpretation and comparative discussion of this data will be discussed in Chapter 4.

3.2 Geochemical Results of Surface Samples

To isolate the present-day generative limits and diagnose the exact structural condition of the organic fraction, pyrolytic testing was applied to the collected surface suite. These specific specimens were recovered directly from subaerial outcrops spanning both the Imbricated and High Folded Zones.

3.2.1 Halabja Section (Imbricated Zone)

The quantitative assessment of this sequence paints a clear picture of profound geochemical depletion. By decoupling the analytical metrics from standard reporting formats, a stark narrative of organic exhaustion emerges:

A baseline evaluation of organic richness reveals a severely impoverished accumulation. Total Organic Carbon (TOC) concentrations hover at minimal levels, constrained within a restrictive band of 0.16 to 0.58 wt%, ultimately yielding a highly suppressed average of 0.332 wt%.

When probing the immediate and future generative capacities of the strata, the extent of the rock's exhaustion becomes unequivocally apparent. The free hydrocarbon fraction (S1) barely registers, fluctuating nominally from 0.06 to 0.09 mg HC/g rock (averaging 0.075 mg HC/g rock). This depletion is most critically reflected in the residual generative potential (S2). Bounded between an anemic 0.02 and 0.04 mg HC/g rock, this metric stabilizes at a trace 0.03 mg HC/g rock mean—a signature indicative of a structural matrix completely devoid of viable, long-term productive capability.

Providing a stark counterpoint to these depressed hydrocarbon yields, pyrolytic carbon dioxide generation (S3) demonstrates an anomalous and remarkable surge. Occupying a much higher threshold, these values stretch from 0.17 to 0.47 mg CO₂/g rock, carrying a substantial average of 0.295 mg CO₂/g rock.

The thermal maturity profile, mapped via Tmax readings, exhibits the erratic and wildly inflated thermal behavior characteristic of heavily compromised kerogen. Recorded temperatures span an extreme gradient from 475°C up to 597°C, pulling the dataset toward a mathematically skewed mean of 501.4°C.

A synthesis of the calculated pyrolytic indices further corroborates this diagnostic framework of advanced environmental degradation:

- **Hydrogen Index (HI):** Reflecting the near-total abstraction of hydrogen constituents, the HI collapses entirely. Yields struggle to register, sitting between a mere 7 and 19 mg HC/g TOC, with an average of just 10 mg HC/g TOC.
- **Oxygen Index (OI):** Acting in inverse proportion to the hydrogen deficit, the OI experiences exceptional inflation. Driven by structural oxygen incorporation, these values spike dramatically between 49 and 160 mg CO₂/g TOC, establishing an unusually high mean of 95.3 mg CO₂/g TOC.
- **Production Index (PI):** As a mathematical consequence of the decimated S2 denominator, the PI registers a severely distorted, high-end profile. Ranging from 0.64 to 0.82 and averaging 0.714, this index highlights the mathematical artifacts introduced by profound kerogen alteration rather than genuine thermal conversion.

Table 1. Pyrolysis data to evaluate Naokelekan Formation rocks for the Halabja surface sections

Sample Number	Sample Type	TOC wt%	Percent Carbonate	S1 mgHC/G	S2 mgHC/g	S3 mgCO ₂ /g	Tmax (°C)	HI	OI	PI
Halabja section										
HN1	Outcrop	0.58	86.44	0.07	0.04	0.39	597	7	67	0.64
HN3	Outcrop	0.23	94.36	0.09	0.02	0.17	486	9	75	0.82
HN5	Outcrop	0.40	91.37	0.06	0.03	0.39	491	8	98	0.67
HN7	Outcrop	0.32	91.96	0.09	0.03	0.47	497	9	145	0.75
HN9	Outcrop	0.34	95.97	0.09	0.03	0.25	492	9	74	0.75
HN16	Outcrop	0.28	90.76	0.06	0.03	0.38	491	11	134	0.67
HN17	Outcrop	0.16	95.15	0.06	0.03	0.26	490	19	160	0.67
HN18	Outcrop	0.26	95.18	0.07	0.03	0.17	475	12	66	0.70
HN19	Outcrop	0.47	93.36	0.08	0.04	0.23	493	9	49	0.67
HN20	Outcrop	0.28	98.19	0.08	0.02	0.24	502	7	85	0.80
Max.		0.58	98.19	0.09	0.04	0.47	597	19	160	0.82
Min.		0.16	86.44	0.06	0.02	0.17	475	7	49	0.64
Average		0.332	93.274	0.075	0.03	0.295	501.4	10	95.3	0.714

3.2.2 Barzinja Section (High Folded Zone)

Located within the High Folded Zone, the Barzinja section mirrors the severe degradational trajectory established in the Halabja region. Subjecting these surface exposures to an identical framework of quantitative analysis reveals a geochemical profile profoundly compromised by the extreme alteration of its indigenous organic material.

Although registering a marginally elevated Total Organic Carbon (TOC) signature relative to the Halabja strata, the overall organic richness remains impoverished. Analytical yields occupy a restricted baseline, spanning from 0.27 wt% to 0.79 wt%, and ultimately stabilize at a mean of 0.48 wt%.

The true extent of this environmental weathering is arguably most striking when quantifying the residual hydrocarbon potential. Free hydrocarbons (S1) are virtually negligible. Fluctuating between a mere 0.01 and 0.07 mg HC/g rock, the fraction averages an anemic 0.048 mg HC/g rock. Concurrently, the intrinsic generative capacity (S2) has been completely obliterated. Yielding a trace average of 0.035 mg HC/g rock—derived from a 0.01 to 0.05 mg HC/g rock spectrum—the organic matrix is practically exhausted, devoid of any meaningful ongoing potential.

Pyrolytic carbon dioxide generation (S3) further characterizes the altered state of the rock. The measured values distribute between 0.14 and 0.40 mg CO₂/g rock, yielding a calculated average of 0.285 mg CO₂/g rock.

Perhaps the most diagnostic indicator of this oxidative damage lies in the thermal maturity metrics. The Tmax readings present an intensely erratic thermal signature, swinging violently from 477°C up to 597°C (averaging 503.375°C). Such pronounced volatility is far from anomalous; rather, it is a classic, expected artifact when attempting to derive maturity data from severely oxidized kerogen.

Table 2. Pyrolysis data to evaluate Naokelekan Formation rocks for the Barzinja surface sections

Sample Number	Sample Type	TOC wt%	Percent Carbonate	S1 mgHC/g	S2 mgHC/g	S3 mgCO ₂ /g	Tmax (°C)	HI	OI	PI
Barzinja section										
BN1	Outcrop	0.42	89.13	0.06	0.05	0.26	597	12	62	0.55
BN3	Outcrop	0.58	71.67	0.03	0.03	0.46	517	5	79	0.50
BN5	Outcrop	0.79	93.90	0.04	0.05	0.38	504	6	48	0.44
BN8	Outcrop	0.68	95.32	0.05	0.03	0.25	489	4	37	0.63
BN14	Outcrop	0.27	89.57	0.05	0.04	0.33	485	15	124	0.56
BN16	Outcrop	0.45	97.22	0.01	0.01	0.24	479	2	53	0.50
BN17	Outcrop	0.30	99.06	0.04	0.02	0.14	477	7	47	0.67
Max.		0.79	99.06	0.07	0.05	0.46	597	15	124	0.78
Min.		0.27	71.67	0.01	0.01	0.14	477	2	37	0.44
Ave.		0.48	91.794	0.0438	0.031	0.285	503.375	7.125	64.125	0.578

3.3 Geochemical Results of Subsurface Samples

Determining the authentic hydrocarbon potential of the Naokelekan Formation necessitates penetrating the severe geochemical distortions left by subaerial exposure. To mathematically isolate this degradational masking effect—and thereby establish the unit's true generative baseline—this analysis anchored its evaluation on a strictly unweathered, subsurface reference dataset.

3.3.1 Taq Taq-1 Well (Reference Data)

Extracted from the Taq Taq-1 well at depths spanning 2061 to 2090 m, ten subsurface core specimens provide a critical diagnostic baseline. Unburdened by the severe environmental

degradation that compromises surface outcrops, this assemblage successfully unmasks the formation's authentic geochemical identity.

The organic richness of the unweathered unit becomes immediately apparent upon quantifying Total Organic Carbon (TOC). Demonstrating substantial accumulation, the analyzed cores yield TOC concentrations spanning 1.04 to 4.16 wt%, ultimately stabilizing at a robust 2.158 wt% mean.

Hydrocarbon generation metrics further substantiate this prolific capacity. The free hydrocarbon fraction (S1) fluctuates from 0.35 up to 6.92 mg HC/g rock, carrying an average of 1.504 mg HC/g rock. Yet, it is the residual generative potential (S2) that proves most revelatory. Averaging 8.914 mg HC/g rock—and reaching peak concentrations of 28 mg HC/g rock from a 1.63 baseline—these exceedingly high yields definitively corroborate the vigorous, unadulterated source potential of the underlying strata.

In stark opposition to degraded surface equivalents, carbon dioxide generation (S3) during pyrolysis remains heavily constrained. The restricted distribution of 0.41 to 1.31 mg CO₂/g rock, alongside a modest 0.92 mg CO₂/g rock average, essentially confirms a depressed structural oxygen content within the intact kerogen network.

Yielding highly reproducible thermal maturity signatures, the Tmax readings accurately isolate the thermal evolution of the sequence. While analytical temperatures fluctuate between 344°C and 429°C, the collective dataset firmly centralizes around a 418°C average.

A synthesis of derived pyrolytic indices paints a cohesive picture of the rock's underlying generative quality:

- **Hydrogen Index (HI):** Exceedingly high values—averaging 347.4 mg HC/g TOC across a broad 147 to 673 mg HC/g TOC spectrum—unequivocally classify the preserved kerogen as highly oil-prone.
- **Oxygen Index (OI):** Reflecting an absence of meteoric oxidation, the OI maintains a suppressed profile bounded between 22 and 116 mg CO₂/g TOC, registering a mean of 52 mg CO₂/g TOC.
- **Production Index (PI):** The current state of hydrocarbon conversion is mapped by the PI, which occupies a tight bracket of 0.09 to 0.2 and yields an overall average of 0.142.

Table 3. Pyrolysis data for the evaluation of Naokelekan Formation rocks in the Taq Taq-1 well

Sample Number	Depth (M)	TOC (wt%)	S1 mgHC/G	S2 mgHC/g	S3 mgCO ₂ /g	Tmax (°C)	HI	OI	PI
Taq Taq-1 well									
1	2061	1.04	0.35	3.01	0.41	427	289	39	0.11
2	2063	3.65	1.61	16.05	0.82	429	440	22	0.09

3	2068	3.51	2	15.98	0.86	427	455	25	0.11
-4	2072	4.16	6.92	28	1.31	344	673	31	0.2
5	2074	1.93	1.03	8.55	0.5	428	443	26	0.11
6	2077	1.4	0.85	4.2	0.75	423	300	54	0.17
7	2078	1.73	0.69	4.33	0.88	423	250	51	0.14
8	2088	1.43	0.52	2.59	1.16	425	181	81	0.17
9	2089	1.11	0.41	1.63	1.29	425	147	116	0.2
10	2090	1.62	0.66	4.8	1.22	429	296	75	0.12
Max.		4.16	6.92	28	1.31	429	673	116	0.2
Min.		1.04	0.35	1.63	0.41	344	147	22	0.09
Ave.		2.158	1.504	8.914	0.92	418	347.4	52	0.142

4. Discussion

4.1 Evidence of Surface Weathering and Oxidation

Relying exclusively on surface-derived data sets precipitates a significant diagnostic error. In such a scenario, the Naokelekan Formation would be erroneously dismissed as an impoverished or "bad" source rock—a classification that fails to account for the catastrophic geochemical depletion occurring at the surface level.

Subaerial Exposure and the Degradation of Organic Carbon

The inherent instability of organic matter when divorced from the subsurface environment cannot be overstated. Within the Halabja and Barzinja sections, the geological record has been compromised by relentless chemical oxidation. This degradation is a direct consequence of prolonged contact with atmospheric oxygen and the pervasive infiltration of meteoric waters over geological timescales.

Empirical Evidence of Kerogen Metamorphosis

Far from a speculative assumption, the oxidative restructuring of the kerogen framework is a documented geochemical reality. This process involves a systematic reorganization where hydrogen atoms are stripped away and replaced by oxygen. The validity of this transformation is anchored in the elevated concentrations of redox-sensitive trace elements, most notably Vanadium (V) and Nickel (Ni), which act as fingerprints for such alteration.

Disparity in Generative Potential (S2)

The most visible casualty of surface oxidation is the formation's residual generative capacity. While unweathered samples from the Taq Taq-1 well demonstrate substantial yields—averaging

approximately 8.914 mg HC/g—the surface counterparts tell a different story. In these outcrops, the S2 peaks are virtually non-existent, often bottoming out at a negligible 0.03 mg HC/g.

Artificial Shifts in Pyrolytic Markers (S3 and OI)

Weathering patterns introduce significant "noise" into pyrolysis data. As the degraded kerogen is heated, it releases disproportionately high volumes of carbon dioxide, leading to an artificial inflation of S3 values. This, in turn, causes the Oxygen Index (OI) to spike, creating a deceptive profile that does not reflect the rock's original state.

The Deceptive Hydrogen Index (HI) and Kerogen Type

Because hydrogen is the primary element lost during subaerial weathering, the resulting Hydrogen Index (HI) for surface samples is radically suppressed. This loss leads to the false identification of "Type IV" or inert carbon. This geochemical "mask" hides the formation's true character: a prolific, oil-prone Type II source rock that remains preserved only within the subsurface.

Concluding Synthesis for Resource Assessment

Ultimately, the primary takeaway is that surface samples are poor proxies for the Naokelekan Formation's true hydrocarbon potential. For a robust evaluation, subsurface datasets are indispensable, alongside the strategic application of geochemical cross-plots to mathematically correct for the distortions introduced by surface-level environmental alteration.

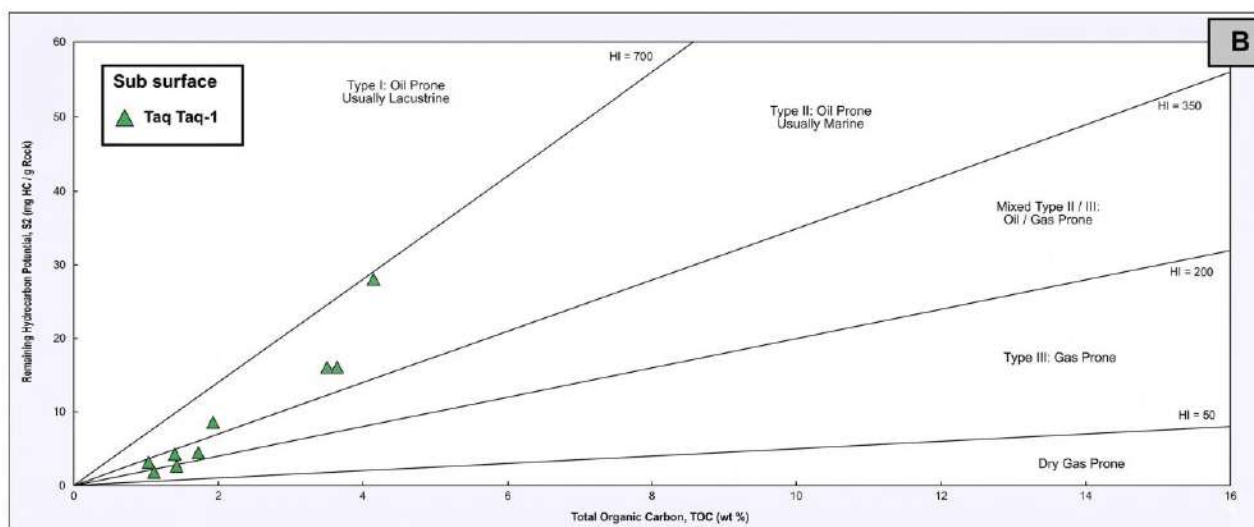
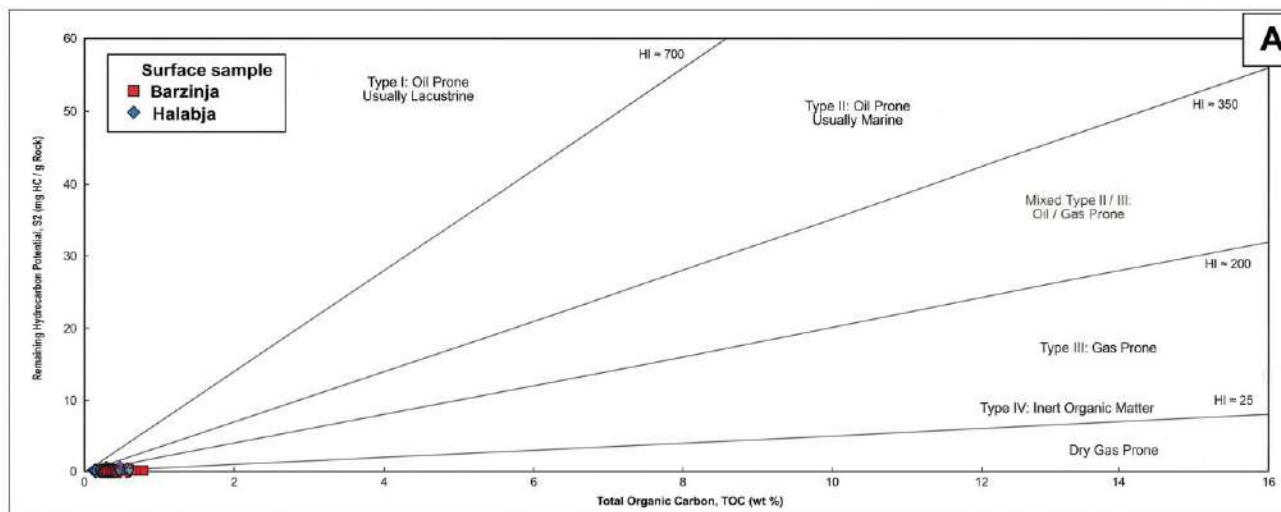
4.2 Evaluation of Organic Richness and Generative Potential

For assessing a potential source rock, the quantity of organic matter from a prospect is represented by Total Organic Carbon (TOC, wt%) and its ability to produce hydrocarbons, as shown by its pyrolysis S2 peak (mg HC/g rock). A basic geochemical cross-plot of TOC versus S2 is used in order to visually identify the generative potential of the source rock. Note that the surface outcrop samples and well samples are separated by the TOC versus S2 cross-plot (Fig. 3), leading to two distinct evaluation clusters. The weathered surface specimens of both Halabja and Barzinja stand close together in the lower-left corner of the diagram. The Halabja samples with an average TOC of 0.33 wt% and an S2 average of 0.03 mg HC/g, and the Barzinja samples average TOC of 0.48 wt%, average S2 0.035 mg HC/g are among the "Poor" generative potential classes. When comparing the figures for this sample, they give us the implication that this exposed Naokelekan Formation does not have sufficient organic content and quality to produce commercial hydrocarbons at all. But as specified in Section 4.1 this is a "false negative" due to excessive surface oxidation that is consuming organic carbon and has completely ruined the generative S2 peak. In contrast, the unweathered subsurface samples from the Taq Taq-1 well contain the true baseline of the Naokelekan Formation. When plotted on the same diagram (Figure 3B), these samples are displaced from the basal to the upper-right quadrant. The subsurface data points mostly fall into either the "Good" or "Excellent" generative potential zones based on TOC values (up to 4.16 wt% (average 2.158 wt%)) and strong S2 peaks (up to 28 mg HC/g (average 8.914 mg HC/g)). The Naokelekan Formation shows organic richness and highly effective hydrocarbon-generating ability prior to surface exhumation and weathering, indicating that it is a prolific source rock regionally.

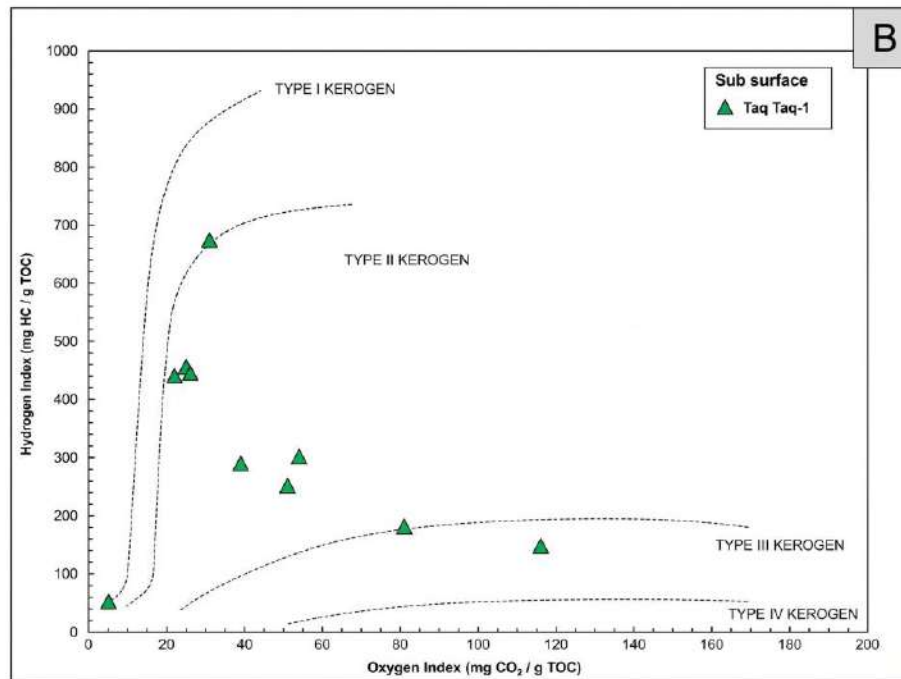
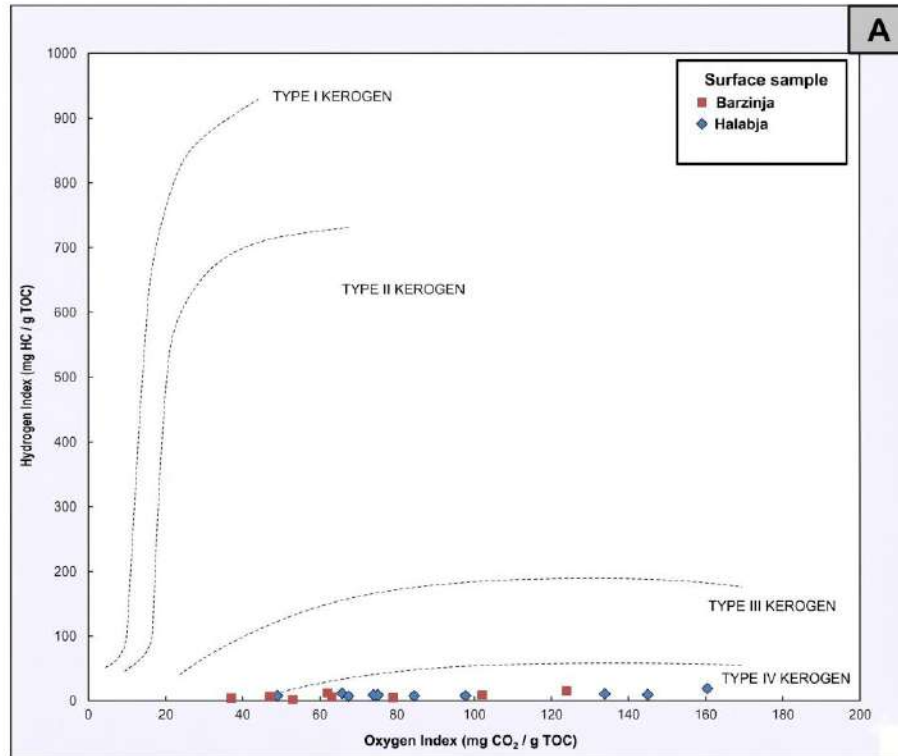
Fig. 3. A — Showing the kerogen types of the Naokelekan Formation in the surface samples of the Halabja and Barzinja sections. B — Comparing with the results of the subsurface samples of the Taq Taq well (Espitalie et al., 1977).

4.3 Kerogen Type and Quality

The very different organic matter (or kerogen) in a source rock is key to determining whether the formation can produce oil, gas, or absolutely nothing. The common methodology for this classification is the Modified Van Krevelen diagram that shows Hydrogen Index (HI) against the Oxygen Index (OI) to classify kerogen into Types I, II, III, and IV. This was highlighted through plotting the Rock-Eval data for Naokelekan Formation on HI vis-a-vis OI diagram (Figure 4), which illustrates the extreme influence of surface weathering and defines the ultimate potential of the formation. At the bottom right of the diagram, for the surface samples from Halabja and Barzinja sections, the points are purely associated with the Type IV kerogen pathway. Numerically, this is due to their relatively very low Hydrogen Index values (10 and 7.125 mg HC/g TOC on average) and abnormally high Oxygen Index values (95.3 and 64.125 mg CO₂/g TOC on average). No geological context could interpret this fact, but from it it would be evident to infer that the Naokelekan Formation possesses simply dead, inert carbon capable of no generative activity. Nevertheless, as previously laid out, this Type IV signature is an artifact of intensive surface oxidation. For the underlying nature of the kerogen, we first have to take the subsurface data from the Taq Taq-1 well to demonstrate true original quality of the kerogen. Plotting these unweathered samples on the Modified Van Krevelen diagram (Figure 4) reveals an entirely different signature. The locations diverge sharply in the upward and leftward direction, largely along the Type II kerogen pathway, with a few samples showing mixed Type II/III organic matter. The high HI values of the subsurface samples (ranging up to 673 mg HC/g TOC, average 347.4 mg HC/g TOC) and the naturally low OI values (averaging 52 mg CO₂/g TOC) strongly support that the unweathered Naokelekan Formation is mainly of high-quality oil-prone marine organic matter. This directly demonstrates that the formation is an oil-producing rock, and the surface Type IV is just another deceptive artifact of the environment



(Fig. 3) A - Showing the kerogen types of the nuclide formation in the surface samples of the Halabja and Barzanja sections,
B - Comparing with the results of the subsurface samples of the Taq Taq well



(Fig. 4) Modified Van Krevelen diagram (Hydrogen Index vs. Oxygen Index) showing the kerogen typing.
The unweathered subsurface samples clearly indicate oil-prone Type II kerogen, while the oxidized surface samples falsely plot as inert Type IV carbon.

4.4 Thermal Maturity Assessment

An organic matter's thermal maturity is an important aspect for assessing whether a source rock is in the "oil window" and actively generating hydrocarbons. Thermal maturity was measured by means of the temperature of maximum hydrocarbon generation (Tmax) and the Production Index (PI) in Rock-Eval pyrolysis. For proper characterization of the maturity of the Naokelekan Formation, the standard maturity guidelines proposed by Peters and Cassa (1994) have been chosen as baseline reference (Table 4).

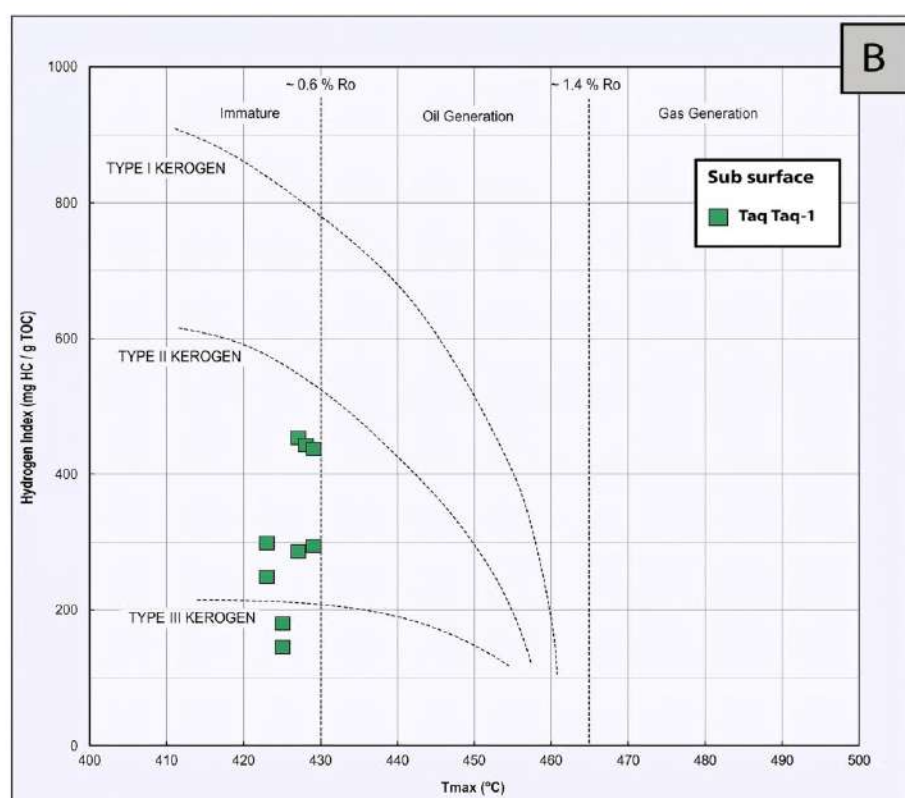
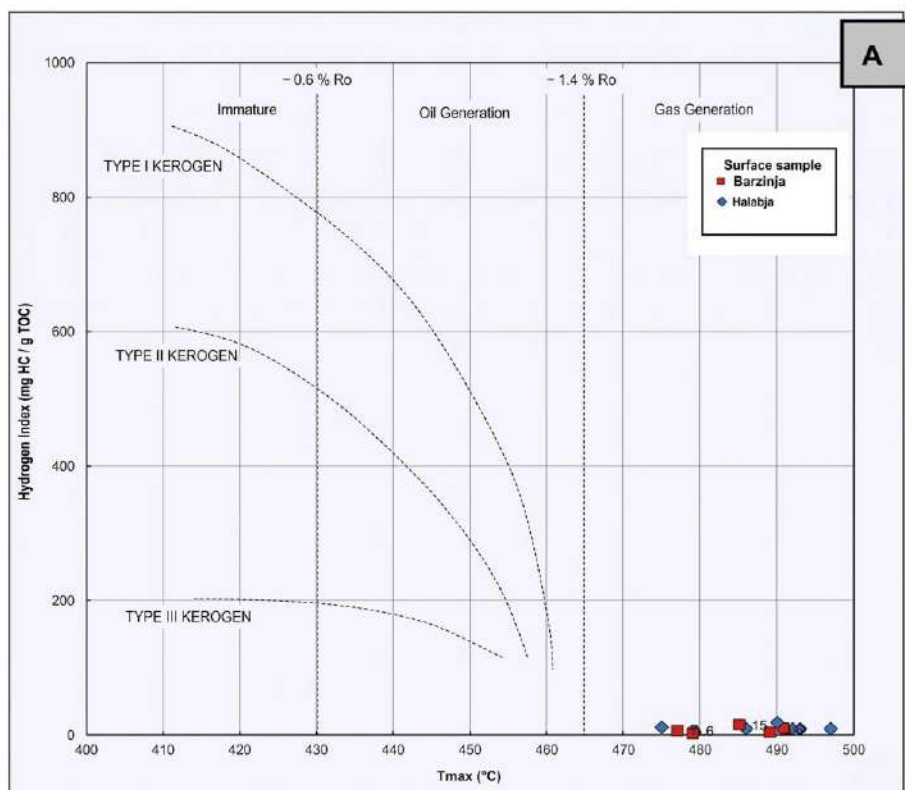
Table 4. Standard geochemical parameters describing the thermal maturation stages of source rocks (after Peters and Cassa, 1994)

Stage of thermal maturity of oil	Tmax (°C)	Production Index (PI)
Immature	<435	<0.10
Mature — Early	435–445	0.10–0.15
Mature — Peak	445–450	0.25–0.40
Mature — Late	450–470	>0.40
Post-mature	>470	—

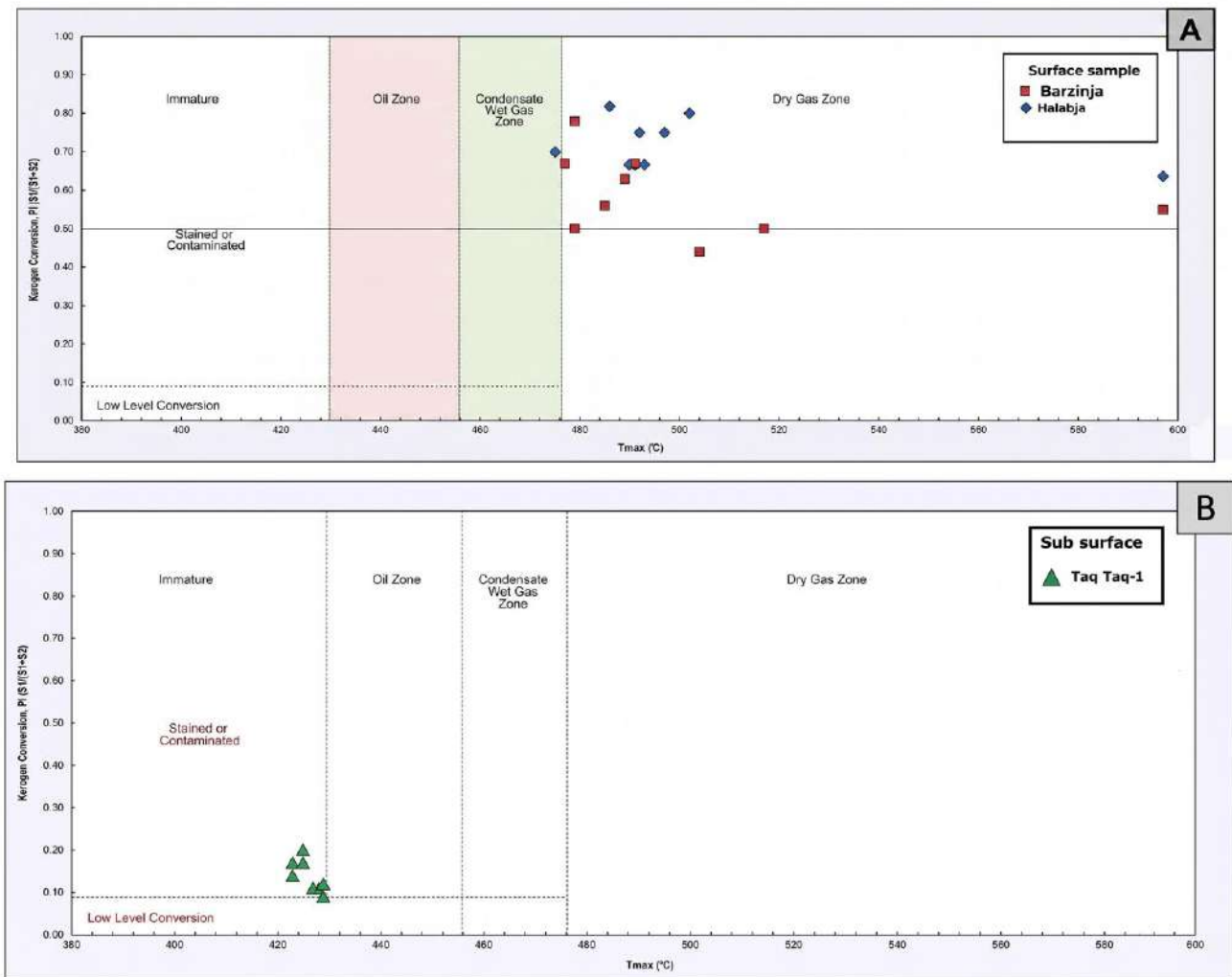
Comparison of the surface samples obtained from the Halabja and Barzinja sections and the standard parameters yields an extremely variable and anomalous pattern. The recorded Tmax for these outcrops fluctuates drastically, from 475°C to a peak of 597°C. From a normal understanding that would derive from Table 4: these results would categorize these surface rocks as wholly "post-mature" or under the dry gas/metamorphic zone. This interpretation, however, is geochemically invalid. Extreme and scattered Tmax readings are a well-documented artifact of severe surface weathering. As oxidation processes have obliterated the generative potential (the S2 peak is flattened to close to zero), the Rock-Eval instrument cannot resolve a clear maximum peak properly, leading to artificially high inflated Tmax temperatures.

As such, the thermal maturity data from the exposed outcrops are not reliable and are not representative of the basin's actual thermal history. To determine the true thermal maturity of the Naokelekan Formation, we need to confirm the unweathered data from its subsurface sample from the Taq Taq-1 well.

The subsurface samples show a sensible and consistent maturation trend, as shown in the Tmax versus Hydrogen Index (HI) cross-plot (Figure 5) and Tmax versus Production Index (PI) diagram (Figure 6). The Tmax values for the Taq Taq-1 well were highly consistent, ranging from 344°C to 429°C (average 418°C), with corresponding PI values averaging 0.142. When plotted on Figure 5 and Figure 6, these subsurface data points cluster accurately within the "Immature to Early Mature" stages, approaching the onset of the oil window. This reliable subsurface data confirms that the unweathered Naokelekan Formation contains well-preserved, high-quality Type II kerogen that is appropriately maturing with depth, contrasting sharply with the deceptively "over-cooked" appearance of the oxidized surface samples..



(Fig. 5) Cross-plot of Tmax versus Hydrogen Index (HI) illustrating the thermal maturation path. The surface samples show falsely high Tmax values due to S2 depletion, while the subsurface samples show reliable early maturation of Type II kerogen.



(Fig. 6) Cross-plot of Tmax versus Production Index (PI) confirming the erratic maturity readings of the weathered surface samples compared to the stable subsurface baseline.

4.5 Final Assessment of the Naokelekan Formation Potentiality

Analysis of geochemical variables, visual cross-plots, and subsurface baselines render a definitive estimate of source rock potential for the Naokelekan Formation at this location. These results clearly show the limitations of looking only at exposed outcrops for organic geochemical analyses. Halabja and Barzinja surface samples have suffered extensive oxidative chemical reactions during exhumation and prolonged surface exposure. This weathering also resulted in the destruction of the hydrocarbon-generating capacity (S2 peak), hydrogen loss from the kerogen structure (collapse of HI to Type IV dead carbon), atmospheric oxygen injection (inflating the OI and S3 peak), and variable and hyperinflated Tmax measurements.

As a result, these outcrops display a “false negative” signature that completely obscures the actual economic worth of the formation. This alteration overprint is cut successfully through, however, as the unweathered subsurface data from Taq Taq-1 well successfully reveals the

actual geochemical form of the formation. The subsurface baselines are indicative of a very well-produced source rock (Naokelekan Formation).

Good organic richness: A typical TOC of 2.158 wt% indicates very good organic richness: With this, this formation carries quite enough organic matter to produce an enormous amount of hydrocarbons.

High-Quality Oil-Prone Kerogen: The high levels of hydrogen index values (at average 347.4 mg HC/g TOC) along with position on Modified Van Krevelen diagram confirm that the preserved organic matter is high-quality Type II kerogen which is extremely well-prepared to generate liquid hydrocarbons (oil).

High Generative Capacity: The strong S₂ values (averaging 8.914 mg HC/g rock) suggest that large residual potential for expelling commercial oil once thermal maturation is achieved. Overall, the Naokelekan Formation should be viewed as a superb oil-source rock to be extracted with great efficiency from its surrounding petroleum system. Geochemical degradation seen on the surface is totally an artifact of environment (weathering and oxidation) and does not show the vast generative potential available inside the unoxidized basinal depocenters which remain below the surface level.

5. Conclusions

these critical conclusions arise based on the integrated geochemical evaluation of the Rock-Eval pyrolysis and TOC data for the Naokelekan Formation from the surface (Halabja and Barzinja sections) and subsurface baseline (Taq Taq-1 well): Severe weathering impact: The surface rocks of the Naokelekan Formation in Halabja and Barzinja sections are characterized by surface weathering and oxidation on an intense scale. This was geochemically supported by the high concentrations of certain trace elements (like Vanadium and Nickel) indicative of highly oxidizing environmental conditions. Destruction of Generative Potential: The intense oxidation process irreversibly degraded the organic material in the exposed outcrops. This degradation caused the hydrocarbon-generating potential (S₂ peak) to be virtually destroyed, and generated a false and depleted geochemical signature (falsely indicating inert Type IV kerogen). Anomalous thermal maturity: Surface samples produce highly irregular and unreliable thermal maturity data (T_{max}). Because the S₂ peak is lost because of weathering, the Rock-Eval instrument outputs unreasonably high, geochemically invalid temperatures, and therefore, falsely declares a post-mature state. The True Subsurface Potential: Based on unweathered subsurface samples from the Taq Taq-1 well, the Naokelekan Formation is a high-value source rock with very high yield. It has great organic richness (mean TOC 2.158 wt%) and high generative potential (mean S₂ 8.914 mg HC/g). Oil-Prone Kerogen: The preserved, unweathered organic matter in the subsurface comprises (on average) Type II kerogen (HI 347.4 mg HC/g TOC). This supports that the formation is highly prone to generating liquid hydrocarbons (oil) and is relatively early in the oil generation window. Final Geochemical Verdict: The seemingly poor hydrocarbon yield from the surface sections is entirely an effect of environmental alteration. This indicates that, for precise petroleum system modeling and source rock evaluation in the region, exploration approaches must be driven by subsurface information, as the Naokelekan Formation is definitively an effective and abundant oil-source rock.

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Estimating Naturally Fractured Oil Reservoir Properties Using Well Testing Techniques.

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ABSTRACT

The conductivity of the fracture network often controls production from a reservoir with fractures, and this conductivity can vary as a result of variations in reservoir pressure. A fracture network of channels interlaced with a primary intergranular matrix makes up a fractured reservoir, a dual property system that has two distinct features: fracture and matrix. Models with uniform dual porosity can be used to imitate the uneven fissures found in naturally fractured reservoirs (NFR). The dual porosity and dual permeability models are two different models of fracture systems. The well-testing methodology is the most common method for characterizing a fractured reservoir during production. It is a set of analytical procedures based on pressure response to time and place, assessed using conventional diffusivity equation solutions. It is an inverse issue in petroleum engineering in which sets of inputs and outputs are known, and the researcher or analyst seeks the controlling system attributes. Rubis software has been employed to create a model that simulates the sort of naturally fractured reservoir seen in Norway's Ekofisk oil field. We collected the pressure at the wellbore reaction during production and closing to examine using Saphir. The conventional models provided by commercial software were deemed inadequate to examine all of the additional complex responses, we conclude observed throughout the case study; They exhibit similar behavior and could be described using a variety of approaches.

NOMENCLATURE

A = cross-sectional area to flow, [ft]²
Bo = oil formation volume factor, [rb/stb]
C = wellbore storage coefficient, [bbl/psi]
 c_t = total system compressibility, [psia]⁻¹
h = net reservoir thickness, [ft]
k = average permeability of the reservoir, [md]
 k_f = fracture permeability (fracture referred to bulk volume), [md]
p = absolute pressure, [psia]
p_i = initial reservoir pressure, [psia]
D = fracture spacing, [ft]
e = fracture width, [inch]
 p_{wf} = flowing bottom-hole pressure, [psia]
 p_{ws} = shut in bottom hole pressure, [psia]
q = production rate, [stb/D]
r = radius, [ft]
 r_e = reservoir drainage radius, [ft]
 r_w = wellbore radius, [ft]
s = skin factor, [dimensionless]
t = time, [days]

Subscripts

f = fracture
m = matrix
e = effective

Greek Symbols

ϕ = porosity, [fraction]
 λ = interporosity flow parameter
 μ = viscosity, [cp]
 Δp = pressure change, [psia]
 Δt = shut in time, [days]
 ω = storativity ratio

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CHAPTER ONE

INTRODUCTION

1.1.Introduction

The Ekofisk oil field in South Norway was first identified in 1969, and in 1972 the first plan for development and operation (PDO) was authorized. One of the most crucial phases in reservoir characterization is permeability analysis (Gennaro, M.2011). Although reliable methods exist for estimating porosity and fluid saturation, dependable permeability is difficult, especially in deep reservoirs estimating the permeability of the South Norway Ekofisk oil field's fractured and vuggy carbonate Formation (Late Cretaceous) is one of the oldest and most productive in the Ekofisk oil field. The Tor Formation's depth is three thousand meters of Ekofisk oil field. In actuality, a large number of fracture outcrops that are analogous to subsurface fracture carbonate reservoirs are also affected.

As a result, all hydrocarbon reservoirs in the section include fractures, and most of them are damaged sufficiently to be considered fractured reservoirs (Boersma, Q.2020). The final point should not be ignored, thus, in recent years; reservoir-scale seismic data has substantially assisted reservoir classification. However, acquiring accurate data and estimating reservoir performance in fractured reservoirs is substantially according to Nelson, R.A. (2001), Maciel (2024), spontaneous cracks appear in practically all reservoirs, splitting the reservoir rock into fragments known as matrix blocks. This is more difficult to prove than in conventional reservoirs. It is essential to distinguish between fracture and matrix permeability and porosity in this specific scenario (Hawez, H., 2021). The reservoir's rock may be regarded as a perpetual continuity if it has a single porosity that doesn't require extra maintenance.

Reservoir-scale seismic data has substantially assisted reservoir classification. However, acquiring accurate data and estimating reservoir performance in fractured reservoirs is substantially more challenging than in conventional reservoirs verifies statement, stating that spontaneous fissures

exist in almost all reservoirs, separating the reservoir rock into fragments known as matrix blocks (Nelson, R.A., 2001, Maciel B. et al., 2024). In this particular situation, it is necessary to differentiate between fracture, matrix permeability, and porosity (Hawez, H., 2021). The reservoir only has one porosity, which doesn't need special care, and the rock of the reservoir may be addressed as a perpetual continuity if:

1. Fractures either do not exist or are isolated as well they only influence regional pore volume along with conductivity.

2. The matrix structure is tight, and whether or not hydrocarbons are present, they are inaccessible because of a lack of matrix permeability.

The matrix itself doesn't contribute to fluid production, but if it has reservoir quality and interconnected fractures, the reservoir can't be considered a single continuum. Their ability to estimate the necessary fracturing parameters and reservoir permeability has been proven by the test events that were used (Hasan H. A. and Hamd-Allah S. 2021).

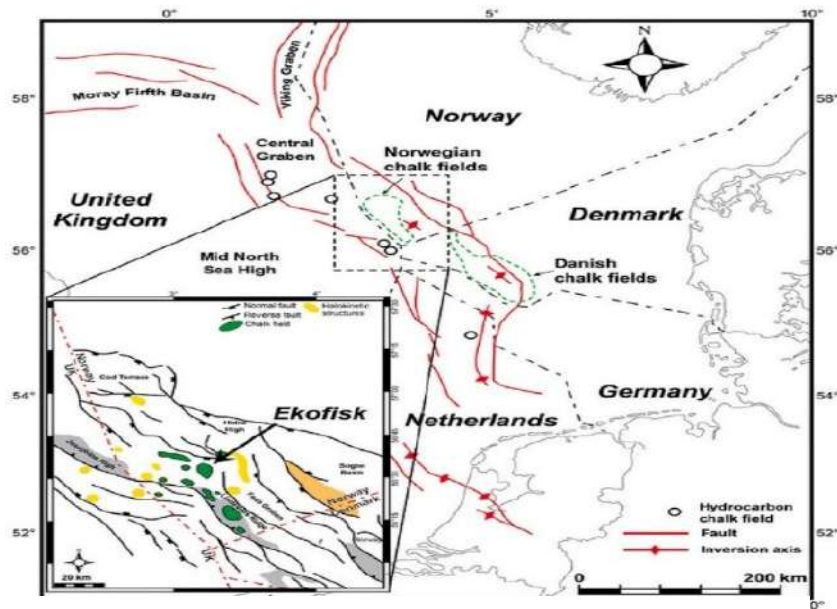
This is explained by the multiple continua concept, where the matrix and fractures dual-porosity (Zhang K, et al., 2021). The main challenge is accurately describing fluid exchange between them during the healing process. Prát, S., 1960 described naturally fractured reservoirs as porous media with varying pore sizes. Large fractures form vugs and channels, while smaller cracks create block structures. These blocks store most of the fluid but have low permeability, whereas fractures allow for high permeability despite having limited storage. While overall permeability is low in two-porosity systems, they often show higher permeability than the matrix and behave differently than homogeneous reservoir (Ali, G, et al., 2019).

Table 1.1. Matrix and fracture porosity and permeability.

Rock Property	Matrix (Storage Media)	Fracture (Transmit Media)
Permeability	Relatively Low	Extremely High
Porosity	Relatively high	Extremely Low

1.2. Location and Tectonic Setting

The Ekofisk field is situated in the northern region of the Norwegian sector (Norwegian Central Graben) in the North Sea. Within off shore oil fields in which the water depth is 70 meters Fig.1.1 (a, b,). The majority of the graben consists of intrabasinal throughout, and its structural configuration is a result of several tectonic phases that can be backdated to the Paleozoic, tectono-stratigraphic in Figure.1.2 illustrating the main tectonic phase Permian to the Miocene including W-E structure sketch of Ekofisk (Gowers,M.1993) Lithostratigraphic of Ekofisk formation (Fig.1.3) summarizes the historical sedimentation of the chalk in the Norway (Quinten B., 2020).



(a)



(b)

Fig.1.1. (a, b,) Location and tectonic map Ekofisk oil field, Norway (Gennaro, B.M., 2011).

System Series	Stress state	Orientation	Salt activity	W-E structural sketch	Structural style
Miocene			Major diapirism		Rapid subsidence
Oligocene					Subsidence
Eocene	Compression				Dome shape
Paleocene	Compression				Transpressional en-echelon folds
Upper Cretaceous	Compression		Involved in transpressive movements - Diapirism		Tectonic inversion
Lower Cretaceous	Thermal subsidence				Basin fill
Lower Cretaceous	Compression		Moved into faults		Sinistral strike-slip along NNW trending faults
Upper Jurassic	Strong Extension		Withdrawal basins along transverse faults		
Middle Jurassic	Extension				
Lower Jurassic	Extension		Salt diapirs and pillows		Fault development guided by pre-Zechstein lineaments
Triassic	Extension				
Permian	Extension		Deposition		Reactivation of basement faults

Fig.1.2. Evolution of Tectono-stratigraphic of the Permian to Miocene (Gowers, M., 1993).

System	Stages	LITHOSTRATIGRAPHIC UNITS			
		Offshore Norway (Isachsen & Tonstad, 1989)	Offshore Denmark (Bailey <i>et al.</i> , 1999)	Offshore UK (Lieberkind <i>et al.</i> , 1982)	Offshore UK (Johnson & Lott, 1993)
Paleocene Upper Cretaceous	61.1 Ma. Danian	Ekofisk Fm.	Ekofisk Fm.	Chalk 6 Unit	Ekofisk Fm.
	65.5 Maastrichtian	Tor Fm.	Tor Fm.	Chalk 5 Unit	Tor Fm.
	70.6 Campanian	Hod Fm.	Magne Fm.	Chalk 4 Unit	Mackerel Fm.
	83.5 Santonian		Thud Fm.	Chalk 3 Unit	
	85.8 Coniacian		Narve Fm.	Chalk 2 Unit	
	88.6 Turonian			Turonian shale	Herring Fm.
	93.6 Cenomanian	Blodøks Fm.	Blodøks Fm.	Plenus Marl Mb.	Hidra Fm.
	99.6	Hidra Fm.	Hidra Fm.	Chalk 1 Unit	

Fig.1.3. Lithostratigraphic of Ekofisk formation in the Norway (Quinten B., 2020)

CHAPTER TWO

THEORETICAL BACKGROUND

2.1. Naturally Fractured Reservoir (NFR)



Fig.2.1. Naturally Fractured rocks

- Simply, It's a type of reservoirs where the reservoir's rock have been broken by geomechanically processes.
- Fracturing occurs when the rock fails because the differential forces acting upon it exceeds its elastic limit thereby causing a rupture.
- Because of these processes, there is mainly two media : Matrix and Fracture.
- Fractures generally improve reservoir flow and connectivity.
- Most of the world's large oil reserves are in naturally fractured and vuggy carbonate reserves that have a complex, heterogeneous porosity system.
- About 22% of the oil reserves in the United States can be found in NFR.

2.2. Fractured Rock Properties

On the fracture characterization level, according to Reiss (1980) the following parameters are used to describe fractures:

- ✓ Distance between fractures.
- ✓ Dip and direction of the fracture plane.
- ✓ Width. degree of cementation. length.

In practice, width is often too small to be measured and estimation of dip (in deviated wells) and direction of the fracture planes requires oriented cores.

2.2.1.Porosity

Porosity can be classified as primary or secondary. Primary porosity forms during deposition of sediments and includes interparticle and intraparticle porosities. Secondary porosity forms after deposition and develops during diagenesis by dissolution, dolomitization and through production of fractures in the rock. The matrix porosity, also often called fabric porosity, can be both primary and secondary. The fracture porosity is always a secondary one and generally refers to porosity that occurs along breaks in a sediment or rock body where there has been little mutual displacement along the fracture. (Heinemann 2005). Fracture porosity, like matrix porosity, is the percentage of a particular void volume in a rock mass compared to its total volume. It accounts for only those voids occurring between the walls of fractures. Matrix porosity, on the other hand, accounts for all voids within a rock other than those within fractures. Thus, matrix porosity includes voids of various origin— vuggy porosity, intergranular porosity, dissolution porosity, etc. (Nelson 2001). As a rough estimation,

fracture porosity given by:
$$\phi_f = \frac{e}{D+e} \times 100\% \quad (2.1)$$

Where e is the fracture width, inch. And D is the fracture spacing, inch.

Horner (1951) describe the fracture porosity by the following oversimplified formula for cubic system:
$$\phi_f \approx \frac{3b}{a} \quad (2.2)$$

Where a is the fracture width and b is the matrix dimension. According to, fracture with $b = 40 \mu m$ and $a = 100,000 \mu m$ has a porosity of $\phi_f = 0.12\%$. Notably, by an order of magnitude is less than average matrix porosity.

Reiss (1980) proposes four types of fracture networks for calculating fracture porosity. The rectangular elements (blocks) have sides a_1, a_2 , and a_3 , and the fracture widths. For the four schemes the fracture porosity is calculated as follows (Hensel 1989):

$$\text{Type (A) Sheets: } \phi_f = \frac{b}{a} \quad (2.3)$$

$$\text{Type (B) Matchsticks: } \phi_f = \frac{2b}{a} \quad (2.4)$$

$$\text{Type (C) Cubes with two effective fracture planes: } \phi_f = \frac{2b}{a} \quad (2.5)$$

$$\text{Type (D) Cubes: } \phi_f = \frac{3b}{a} \quad (2.6)$$

And provides the following expression to estimate minimum fracture porosity:

$$\min \phi_f = \frac{\sqrt[3]{\frac{J \mu_o B_o f_s^2 \log \frac{r_e}{r_w}}{h}}}{578} \quad (2.7)$$

Where f_s is a parameter depends on fracture network, cm/cm^2 . J is the productivity index, $\frac{m^3}{D} / bar$. μ_o is the oil viscosity, cP . B_o is the oil formation volume factor, sm^3/rm^3 . r_e/r_w is the ratio of drainage to well radii. h is the thickness of pay zone, cm . In field unit we can write:

$$\min \phi_f = \frac{\sqrt[3]{\frac{\frac{1 m^3}{0.159 bbl} \frac{1 psi}{0.0689 bar} J \left[\frac{bbl}{psi} \right] \mu_o [cp] B_o \left[\frac{STB}{RB} \right] \left(\frac{1 ft}{30.48 cm} \right)^2 f_s^2 \left[\frac{1}{ft^2} \right] \ln \frac{r_e}{r_w}}{\frac{30.48 cm}{1 ft} h [ft]}}{578} \quad (2.8)$$

$$\min \phi_f = \frac{\sqrt[3]{\frac{J \mu_o B_o f_s^2 \ln \frac{r_e}{r_w}}{h}}}{3913} \quad (2.9)$$

Nelson (2001) noticed that there is no big matter in assuming that : $\ln r_e/r_w = 7$, so the last equation could be -reasonably- written as:

$$\min \phi_f \approx \frac{\sqrt[3]{\frac{J \mu_o B_o f_s^2}{h}}}{2046} \quad (2.10)$$

$$\text{For } \mu_o B_o = 1 \text{ cp } \frac{STB}{RB}, \min \phi_f \approx \frac{\sqrt[3]{\frac{J f_s^2}{h}}}{2046} \quad (2.11)$$

$$\text{By definition, } J_s = \frac{J}{h}, \min \phi_f \approx \frac{\sqrt[3]{J_s f_s^2}}{2046} \quad (2.12)$$

It should be noticed that fracture porosity is scale dependent since a constant fracture width, e , varies as a function of distance between fractures. This means that fracture porosity can be a 100% in a specific location in the reservoir while the average porosity for the reservoir as a whole can be as low as 1% (Ajaya 2000). Nelson (2001) provides the following guidelines for fracture porosity:

Table 2.1. Fracture porosity guidelines

Always Less Than	2%
Excluding Small Zones Less Than	1%
General Less Than	0.50%
Vuggy Fractures	O-Large

2.2.2. Permeability

The permeability of a porous rock is a measure of the ability to transmit fluids. A reservoir can have primary and secondary permeability. The primary permeability is referred to as matrix permeability, the secondary permeability can be either called fracture permeability or solution vugs permeability. Matrix- and fracture permeability are other important parameters that have to be known for an estimate of the influence of the fractures on the overall reservoir performance. Solution vug permeability refers to an increased permeability in matrix rocks (especially in carbonate reservoirs) where the natural permeability of the matrix is increased by percolation of acid waters that dissolve the matrix rock. The permeability in these flow channels can be calculated by combining Darcy's law for fluid flow and Poiseuille's law for capillary flow. Open fractures in Naturally Fractured Reservoirs generally have a higher permeability than the matrix, building the flow channels of the system.

The flow rate through a narrow cleavage can be calculated by Lamb's law:

$$q = - \left(\frac{W^2}{12} \right) \frac{A}{\mu} \frac{dp}{dx} \quad (2.13)$$

where W is the effective fracture aperture (fracture width). The fracture cross section A is the product of the fracture width W and the breadth b . μ is the viscosity, and dp/dx is the pressure gradient. The flow rate can also be expressed by the Darcy equation: $q = -k \frac{A}{\mu} \frac{dp}{dx}$ (2.14)

$$\text{Then: } k = \frac{W^2}{12} \quad (2.15)$$

for field units where W in inches and k_f in md: $k_f = 54 \times 10^9 W^2$ (2.16)

Thus, for a fracture with 1 milli-inch aperture, the permeability is 54,000 md or 54 Darcies.

2.3 Fracture's Basic Properties

- Fracture Porosity

- Fracture porosity is a percentage of void space in fractures compared to the total volume of the system.
- It's very small and generally not exceeds 2%.
- It's a scale dependent.

- $\phi_f = \frac{e}{e+D}$ (2.17)

- Fracture Permeability

- the ability if a fracture to allow the flow of fluid through it.
- Very high permeability through fracture is common.
- $k_f = 54 \times 10^9 w_f^2$ (2.18)

- Fracture Compressibility

- The ratio of the fracture volumetric strain to the change in pressure.
- $c_f = \frac{1}{\phi_f} \frac{d\phi_f}{dp}$ (2.19)
- $c_f \approx c_o$

- Saturations-Relative Permeability Relation in Fractures

-
-
- K_r is generally assumed as a linear function of saturation (the simplest relation), as shown in Figure (2.2)

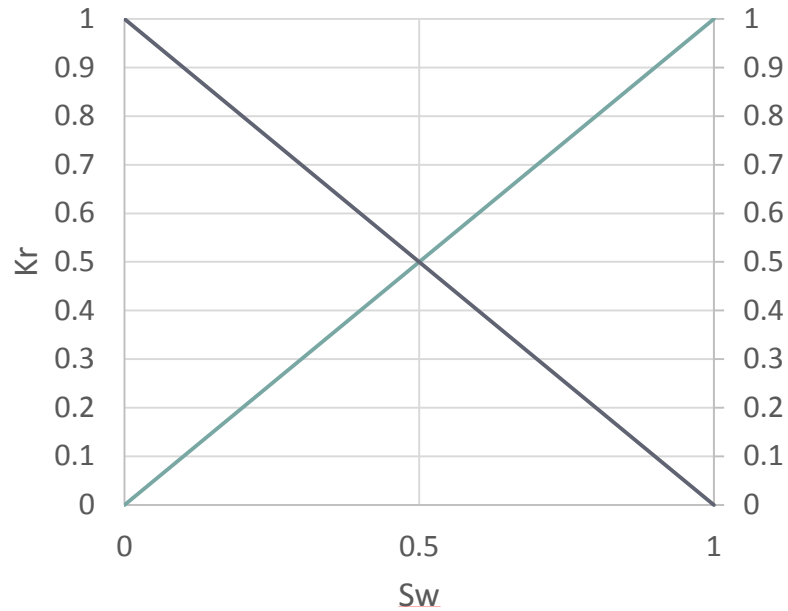


Fig. 2.2. Saturations-Relative Permeability Relation in Fractures

2.4. NFR Types

- **Type I:** Fractures provide the essential reservoir porosity and permeability.
- **Type II:** Fractures provide the essential reservoir permeability.
- **Type III:** Fractures assist permeability in an already producible reservoir.
- **Type IV:** Fractures provide no additional porosity or permeability.

2.5. NFR Types' Characteristics

Type I

- Large drainage areas per well
- Few wells needed for development
- Good reservoir quality-well information correlation
- Easy good well location Identification
- High initial potential

Type II

- Can develop low permeability rocks
- Well rates higher than anticipated
- Hydrocarbon charge often facilitated by fractures

Type III

- Reserves dominated by matrix properties
- Reserve distribution fairly homogeneous
- High sustained well rates
- Great reservoir continuity

Type IV

- Reservoir typically compartmentalized
- Permeability anisotropy may be unlike that in adjacent fractured reservoirs with different fracture style

2.6. NFR Types' Problems

Type I

- Rapid decline rates
- Possible early water encroachment
- Size/shape drainage area difficult to determine
- Reserves estimation complex
- Additional wells accelerate but not add reserves

Type II

- Poor matrix recovery (poor fracture- matrix communication)
- Poor performance on secondary recovery
- Possible early water encroachment
- Recovery factor variable and difficult to determine

- Highly anisotropic permeability
- Unusual response in secondary recovery
- Drainage areas often highly elliptical
- Interconnected reservoirs
- Poor log/core analysis correlation, Poor well test performance

- Wells underperform compared to matrix capabilities
- Recovery factor highly variable across field

2.7. NFR Types' Examples

Type I	Type II	Type III
-Amal, Libya -Ellenberger, Texas -Edison, California -Wolf Springs, Montana -Big Sandy, Kentucky	-Agha Jari, Iran -Hart Kel, Iran -Rangely, Colorado -Sprayberry, Texas -La Paz/Mara, Venezuela	-Kirkuk, Iraq, -Gachsaran, Iran -Hassi Mesaoud, Algeria -Dukhan, Qatar, -Lacq, France -Cottonwood Creek, Wyoming

Type IV No certain available

2.8. Dual Porosity Model

Double-porosity systems reduce the heterogeneities in the vuggy naturally fractured reservoir, such as fractures, vugs, caverns, and cavities, into essentially two media: a conductive network and a storative matrix. The conductive network provides reservoir fluid flow channels while the reservoir fluids are stored in both media. The models proposed to date differ conceptually only in the assumptions made to describe fluid flow in the matrix. The models consider regularly shaped matrix blocks such as cubes, parallelepipeds, cylinders, or spheres, and assume that fluid transfer between matrix and fractures occurs through transient or pseudo-steady state conditions. The model is illustrated in Figure 2.3.

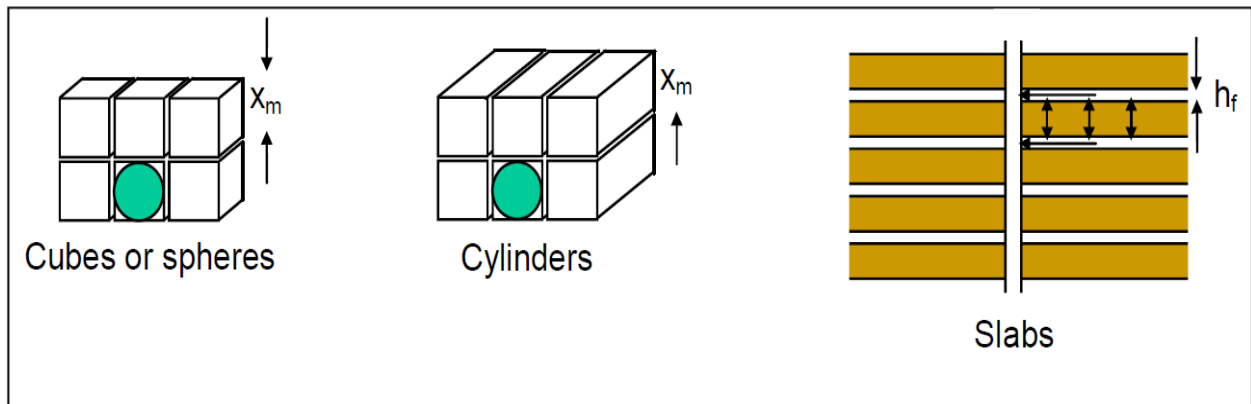


Fig. 2.3. Schematics for Dual Porosity Models

The models are characterized by the same parameters used to characterize homogeneous (single porosity) reservoirs with two additional parameters, the storativity ratio ω and the interporosity flow coefficient, λ . These two parameters, ω and λ , are usually determined from pressure transient analysis.

The storativity ratio, ω determines the amount of fluid stored in the fracture system compared to the total fluid in the reservoir (matrix and fracture), defined as:
$$\omega = \frac{\phi_f C_{tf}}{\phi_f C_{tf} + \phi_m C_m} \quad (2.20)$$

where ϕ is porosity and Ct is total compressibility. Suband m represents fracture and matrix, respectively.

The interporosity flow coefficient determines the fluid exchange interaction between the matrix system and fracture system. High value of λ indicates the fluid easily flows from the matrix to the fracture system, while low values of λ indicate the opposite. The interporosity flow coefficient λ is defined as:
$$\lambda = \alpha r^2 w \frac{k_m}{k_f} \quad (2.21)$$

where k_m is the permeability of the matrix, k_f is the permeability of the fracture network, and α is a system geometric factor that depends on the shape of the matrix blocks and has a dimension of length: $\alpha = \frac{A}{xV}$ (2.22) where A is the surface area of matrix blocks, V is the volume of matrix blocks, and x is the characteristic length. For uniformly spaced fractures: $\alpha = 4n(n + 2)/ x^2$ (2.7), n = number of normal sets of fractures.

For squares and spheres, $n = 3$, and $\lambda = \frac{60}{Xm^2} \frac{k_m}{k_f} r_w^2$ (2.23)

where X_m is the length of the cube side of the sphere diameter.

For cylinders, $n = 2$ and $\lambda = \frac{32}{Xm^2} \frac{k_m}{k_f} r_w^2$ (2.24)

where X_m is the length of a square side, or the diameter of a circular cylinder.

For slabs, $n=1$ and $\lambda = \frac{12}{h_f^2} \frac{k_m}{k_f} r_w^2$ (2.25), h_f =the fracture thickness.

2.9. Triple Porosity Model

The triple porosity model is an extension of the double porosity model. In the triple porosity model, three mediums are considered: the fracture system, the rock matrix system, and the vug/cavity system.

The triple porosity model is based on the assumption that the fracture system interacts with both the matrix system and the vug system. The matrix system provides primary porosity, while the vug system provides a high secondary porosity comparable to or greater than that of the matrix system. The matrix and vug system provides storage space for the reservoir fluid but has no direct contribution to the global fluid flow and transport. Similar to the dual porosity model, fluid flow into the well occurs only through the fracture system. This model is known as a triple porosity/ single permeability model.

The assumptions of the model are:

- The reservoir is of uniform thickness.
- slightly compressible fluid.
- Fluid flow into the well is radial and occurs only through the fracture system.
- The properties such as permeability, initial porosity, and compressibility within each porosity system are constant.

2.10. The Main Reservoir Gridding Systems

-
-
-
- Regular cartesian grids
 - Hexahedral grids
 - Grid refinement
 - Other gridding systems
 - Triangular or tetrahedral grids (special cases of PEBI)
 - Curvilinear grid systems (less used)
 - Radial grids
 - Multiple-domain hexahedral grids
 - Unstructured grids
 - Orthogonal grids

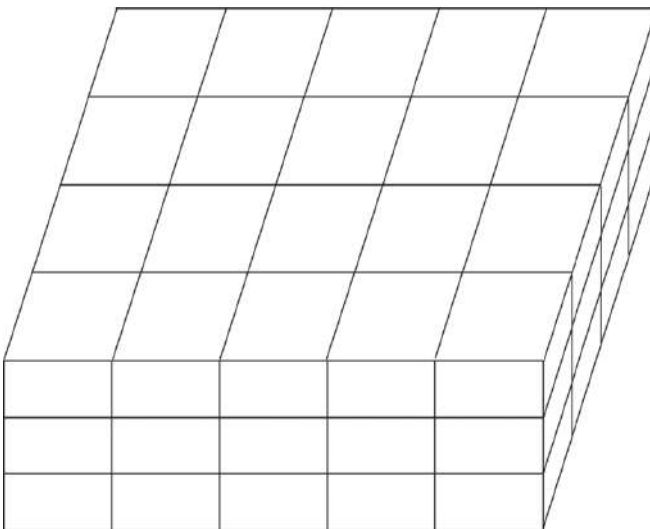


Fig.2.4. Regular cartesian grids (The Simplest)

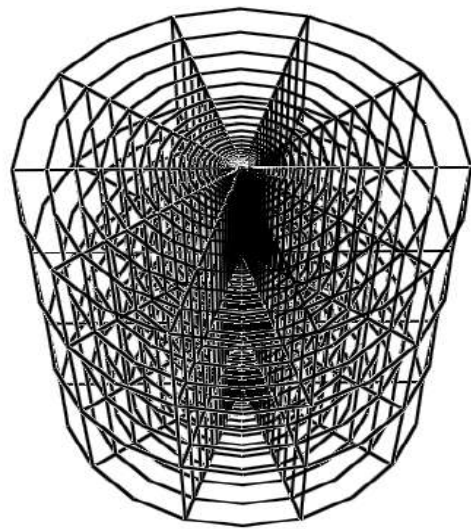


Fig.2.5. Radial grids (r, z, θ model)

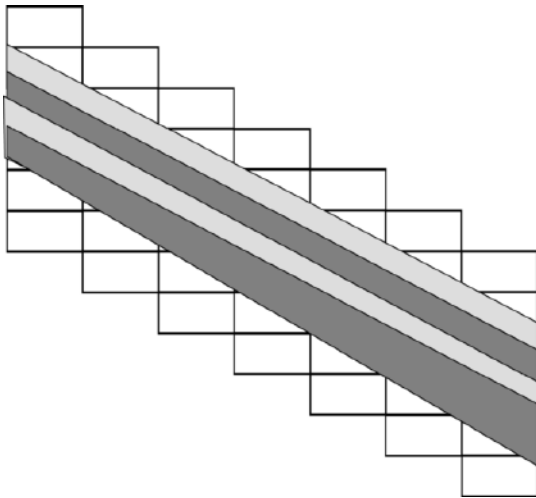


**Fig.2.6 .Orthogonal grids
(used to represent dip)**

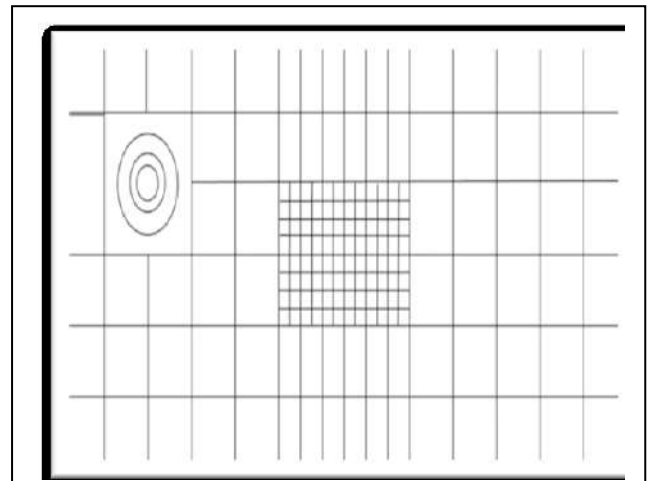


Fig. 2.7 .Grid refinement

-To increase level of detail around an item of interest such as a well in our study.
-Replacing a set of cells in the original grid by a finer grid.

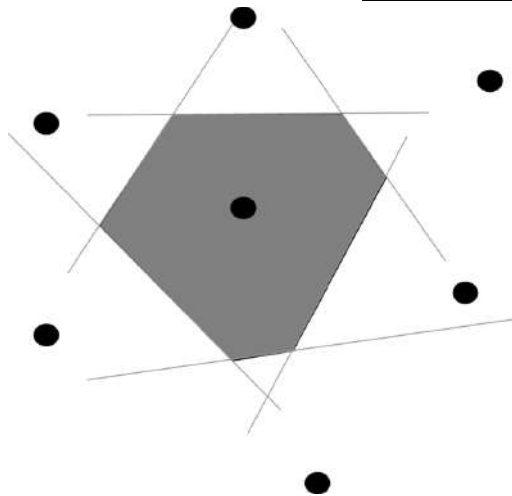


Fig. 2.8 . Unstructured grid

- ✓ The problems involved in using a regular structured grid to represent reservoir geometry can be avoided by using an *unstructured* grid.

-
-
- ✓ This is constructed around a set of solution points that need not have a particular indexing scheme. These points may be triangulated into a mesh of triangles or tetrahedra.

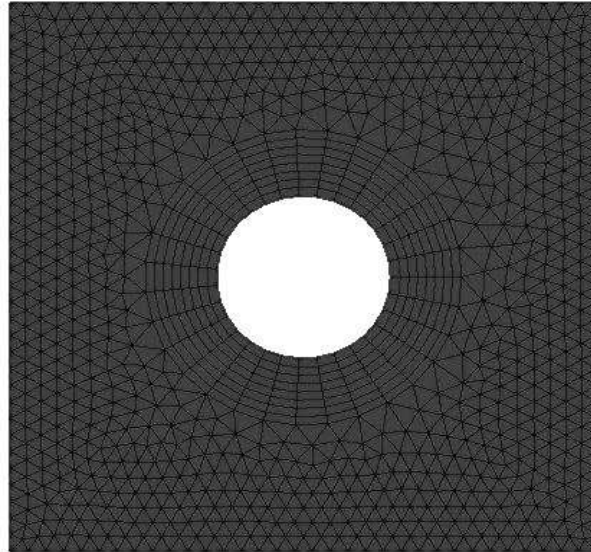


Fig. 2.9. Unstructured grid (Hybrid grid)

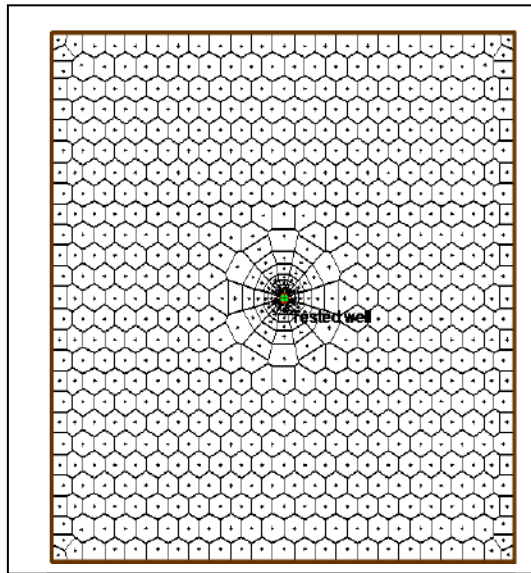


Fig. 2.10. PEBI grid

- The perpendicular bisector (PEBI) method introduced into reservoir simulation by Heinemann used a technique also known as a Voronoi grid.
- Starting from any set of solution points, the PEBI cell volumes are defined by the perpendicular bisection planes between these points.

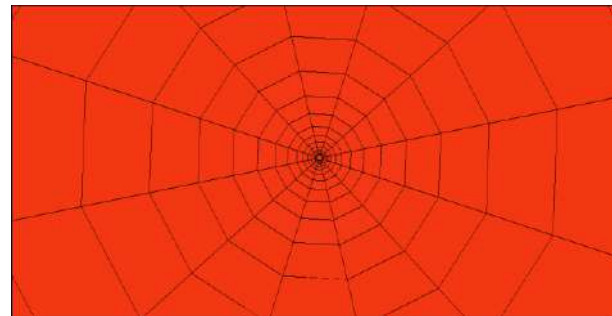
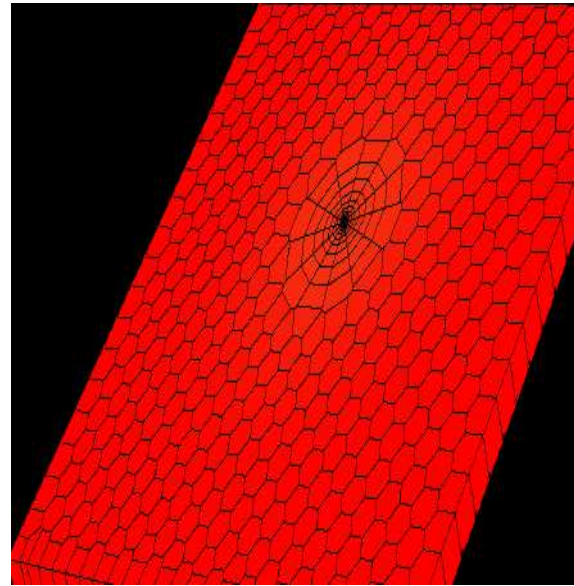


Fig. 2.11. PEBI-Hybrid Grid System

We've Used PEBI-Hybrid Grid System – The Most Available Accurate System

CHAPTER THREE

METHODOLOGY AND MATHEMATICAL MODELING

3.1. Methodology

According to Reiss (1980), the following characteristics are used to define fractures:

1. A gap across fractures.
2. The fracture plane's direction and dip angle.
3. The degree of cementation length based on width.

In practice, the width is often too small to be measured, and estimation of dip (in deviated wells) and direction of the fracture planes requires oriented cores.

Rubis software is a specialized tool for creating and analyzing 3D simulations of geological formations, which is crucial for fields such as geology, petroleum engineering, and environmental science. It allows users to construct detailed mesh-based models that represent geological structures and formations with high precision. In the image, the Kappa model refers to a specific geological formation, likely incorporating parameters such as rock permeability, porosity, and structural characteristics. By defining a mesh over the 3D model, different attributes and behaviors can be simulated and visualized with Rubis by defining a mesh over 3D model.

This enables geoscientists and engineers to predict how resources, such as oil, gas, or groundwater, move through rock layers or to understand the mechanical stability of a formation. The second software is Saphir, which is a specialized software tool used in well testing, primarily within the oil and gas industry. It allows engineers to analyze pressure and flow rate data from wells to understand reservoir properties and performance. By interpreting data from well tests, Saphir helps estimate key parameters like permeability, porosity, and skin factor, which are essential for assessing the productivity of a well and the characteristics of the surrounding reservoir. This software is highly

valuable in designing optimal extraction strategies, evaluating reservoir health, and planning future drilling or production operations. The current version of Saphir, Kappa's software for Pressure Transient Analysis (PTA) in well logging, is version 5.60, part of Kappa's Generation 5 software suite (Hassan, A. et al., 2021).

3.2. Mathematical Modeling

The differential equation for fractures, which exhibits unsteady-state behaviour according to Odeh, A. S. (1965), can be formulated as follows using dimensionless variables:

$$\frac{1}{r_D} \frac{\partial}{\partial r_D} \left(r_D \frac{\partial p_{Df}}{\partial r_D} \right) + \lambda_{mf} (p_{Dm} - p_{Df}) + \lambda_{mv} (p_{Dv} - p_{Df}) = \omega_f \frac{\partial p_{Df}}{\partial t_D} \quad (3.1)$$

The equation for a matrix's blocks is:

$$-\lambda_{mv} (p_{Dm} - p_{Df}) - \lambda_{mf} (p_{Dm} - p_{Df}) = (1 - \omega_f - \omega_v) \frac{\partial p_{Dm}}{\partial t_D} \quad (3.2)$$

For the vugs, the equation is:

$$\lambda_{mv} (p_{Dm} - p_{Df}) - \lambda_{vf} (p_{Dv} - p_{Df}) = \omega_v \frac{\partial p_{Dm}}{\partial t_D} \quad (3.3)$$

The following equation provides the dimensionless variables:

$$p_{Dj} = \frac{2\pi k_f h(p_i - p_j)}{q \mu B_o} \quad (3.4)$$

Where j stands for any necessary vugs or fractures.

$$t_D = \frac{k_f t}{\mu r_{w2} (\phi_f C_{tf} + \phi_m C_{tm} + \phi_v C_{tv})} \quad (3.5)$$

The definition of the inter-porosity factors is:

$$\lambda_{mf} = \frac{\alpha_{mf} k_m r_w^2}{k_f} \quad (3.6)$$

$$\lambda_{mv} = \frac{\alpha_{mv} k_m r_w^2}{k_f} \quad (3.7)$$

$$\lambda_{vf} = \frac{\alpha_{vf} k_v r_w^2}{k_f} \quad (3.8)$$

The term α_{ij} is the flow how e factor interporosity between mediums i and j. The fractures and vugs storativity ratios, ω_f and ω_v , represent the fluid stored in fractures and vugs relative to the total reservoir fluid (Odeh, A. S., 1965).

$$\omega_f = \frac{\phi_f C t_f}{(\phi_f C t_f + \phi_m C_m + \phi_v C_{tv})} \quad (3.9)$$

$$\omega_v = \frac{\phi_v C_{tv}}{(\phi_f C t_f + \phi_m C_m + \phi_v C_{tv})} \quad (3.10)$$

Storativity ratios can be used to show the storative porosity systems interact with the fractures or vugs and begin to produce into the fractures. When the matrix and fracture fluid transfer has reached pseudo steady state flow conditions, a horizontal straight line representing homogeneous radial flow from the matrix and fracture system is observed again on the derivative curve.

CHAPTER FOUR

RESULTS AND ANALYSIS

The petro-physical characteristics of the Ekofisk oil field are shown in Table 2. The initial reservoir pressure was 7135 psi, whereas the bubble-point pressure was 5443 psi. The volatile oil resource was undersaturated at datum (-10400ft). With a reservoir temperature of 131°C (268°F) at the datum (Toublanc, A.,2005), The solution gas-oil ratio (GOR) for the 36° API gravity crude was 1547 (Table.4.1).

Table 4.1. An excerpt from the Ekofisk oil field's original data

Lithology	Chalk
The reservoir midpoint depth, ft	10,400
Total area, acres	12,071
Net pay thickness with $g > 15\%$ and $Sw < 50\%$, ft	590
Average reservoir porosity, %	31.7
Average permeability of matrix, md	1
The range of matrix permeability, md	0.1-10
Well test maximum permeability, md	200
The initial pressure of the reservoir at 10,400 ft, psig	7,120
The reservoir temperature at 10,400 ft, °F	268
The temperature gradient of the reservoir, degrees/100 ft	2.5
Saturation of water, %	23.6
Initial gas oil ratio, SCF/STB	1530
Initial oil formation volume factor, bbl/STB	1.78
The specific gravity of oil, API	36

The transition from a single block or tank model to an enormous number of blocks is known as reservoir simulation.

Gridding is used in reservoir modelling to transform the field's geological model into a discrete system that can be used to solve fluid flow equations. A variety of analytical techniques are used in well testing to analyze the reservoir behavior and estimate its properties. Using Rubis software, we simulated genuine field data for the Ekofisk oil field using dual-porosity and permeability models to determine the well's response (fig.4.1a,b). Saphir software was then used to assess the results of the Pressure Build-Up and Pressure Drawdown Test.

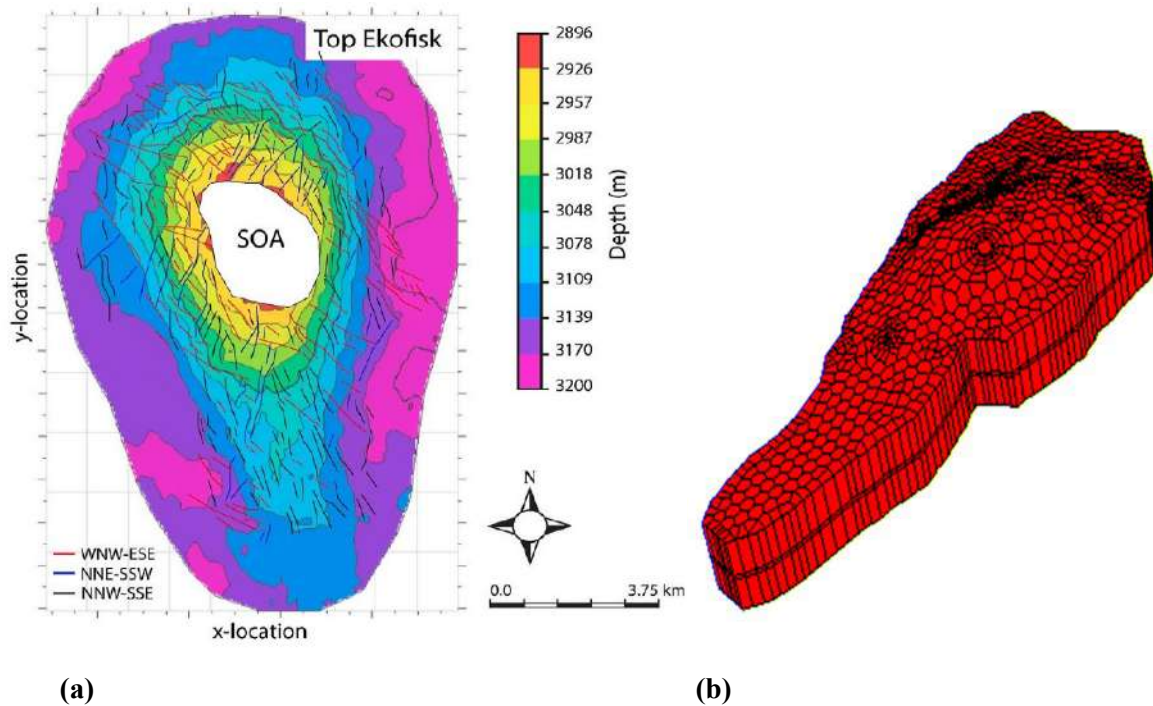


Fig.4.1 (a) The top view of the Ekofisk oil field; (b) Simulation with the 3D Rubis of the Kappa model.

As shown in Table 4.2, there are three formations in the Ekofisk oil field, each with a different net pay thickness and rock characteristics. The well-test history is displayed below for both drawdown and build-up tests, which have been used to inform reservoir properties as a result of build-up and drawdown pressure (Horner, D. R.,1951).

Table 4.2. The reservoir formations of the Ekofisk oil field.

Ekofisk Formation	Tight Zone	Tor Formation
$h_{avg}=440\text{ft}$	$h_{avg}=50\text{ft}$	$h_{avg}=375\text{ft}$
$k_{mavg}=3\text{ md}$	$k_{mavg}=0.01\text{ md}$	$k_{mavg}=3\text{ md}$
$k_{favg}=100\text{ md}$		$k_{favg}=100\text{ md}$
$\phi_{avg}=39\%$	$\phi_{avg}=10\%$	$\phi_{avg}=35\%$

The Ekofisk and Tor formations are reservoir rocks. The fine-grained limestone (chalk) that makes up both formations was mostly created from the skeletal remains of pelagic unicellular algae known as coccolithophorids. These algae produce calcareous exoskeletons, or coccospheres, which are

constructed of coccolith-shaped platelets. The matrix of these formations is predominantly made up of coccolith platelets, ranging in size from 1 to 2 μm . While entire coccoliths are frequently noticed, conserved coccospheres are uncommon. The chalk formations are characterized by high porosity but low matrix permeability. However, natural fractures enhance the effective permeability, reaching values of up to 100 millidarcies. A cumulative pay thickness of more than 1,000 feet is present in the reservoirs. The Tor Formation is found beneath the Ekofisk Formation, which is located at a depth of around 9,600 feet. It dates to the Maastrichtian age of the Late Cretaceous period. These two formations are separated by the Tight Zone, a fifteen-meter-thick horizon of low-porosity chalk that acts as an impermeable barrier between these two reservoirs. The overburden involves approximately 9,300 feet of clays and shales, some exhibiting extremely low permeability and functioning as an effective cap rock. This overburden becomes overpressure below a depth of about 4,500 feet. The source rock is believed to be situated within the Triassic to Jurassic sequences of continental and shallow marine sediments, specifically the Kimmeridgian shales.

4.1. Test History of Well #1

In this field, we have selected one oil well to model. As seen in Fig.4.2. This well was closed for two days after being allowed to produce at 1000 STB/D for two days. The link between oil and gas flow rates, as well as the relatively short equal time flow for two days to clean out the well and the allowed shut-in times to stabilize flowing pressure, are represented by the lower and middle curves. The link between flow pressure and flow time is shown by the upper curve.

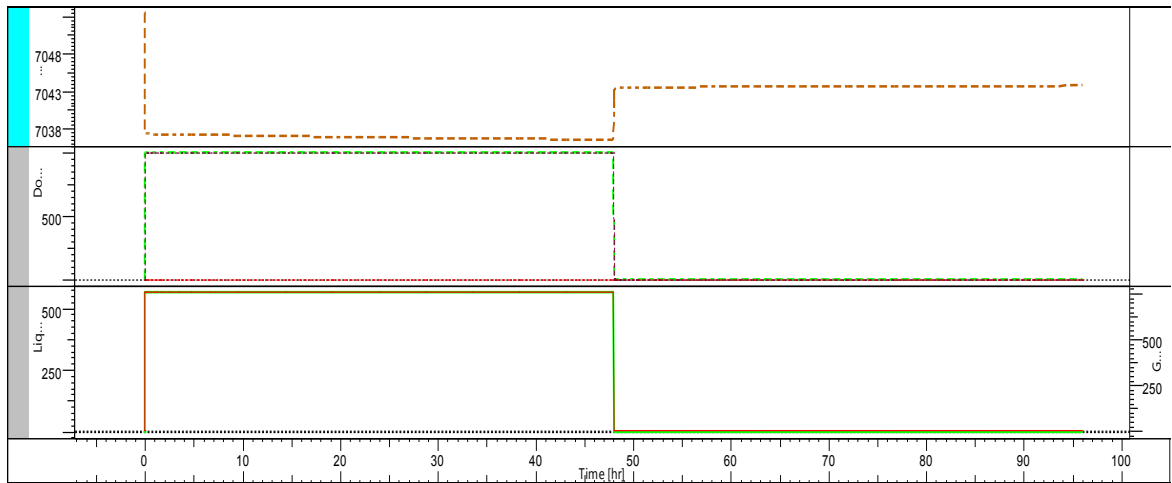


Fig.4.2. Pressure (psi), downhole rate (bbl/D), liquid rate (STB/D), gas rate (MSCF/D) vs. time (hr).

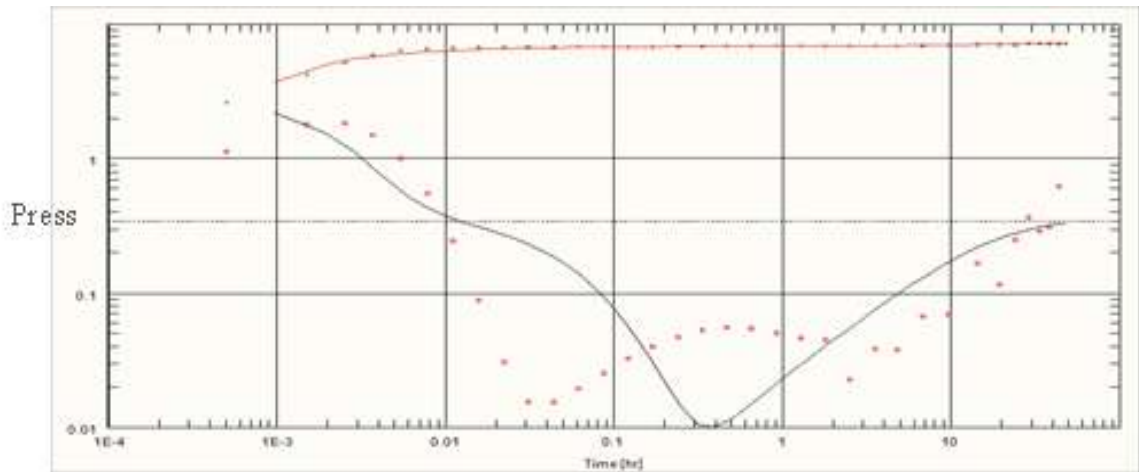


Fig.4.3. Derivative (psi) vs. dt (hr), log-log plot, p-p @ dt=0.

Type Curve: No appropriate matching seems to exist.

4.2. Drawdown Test

For the drawdown test, the following details are needed, including: $C=0.0136\text{bbl/psi}$, $S=2.59$, reservoir and boundary pressure $P_i=7044.08\text{psi}$, $k_h=89700\text{md.ft}$, $K=101\text{md}$, $\omega=0.0574$, $\lambda=1.09\text{E-}7$. The drawdown test results are shown in (Figs. 4.4 and 4.5).

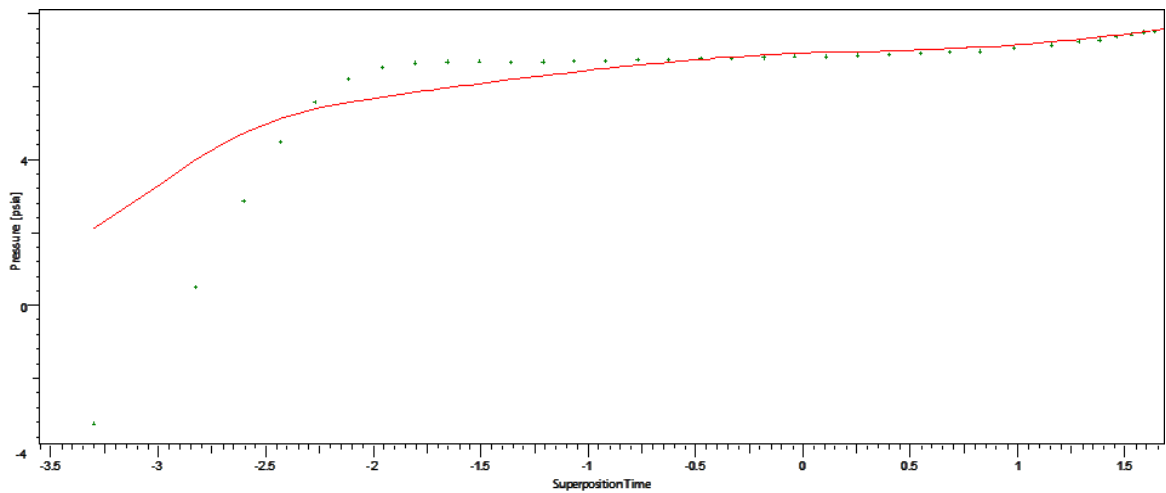


Fig.4.4. Semi-log plot of pressure (psi) against superposition time: $(\Delta p).Q/q(t)$.

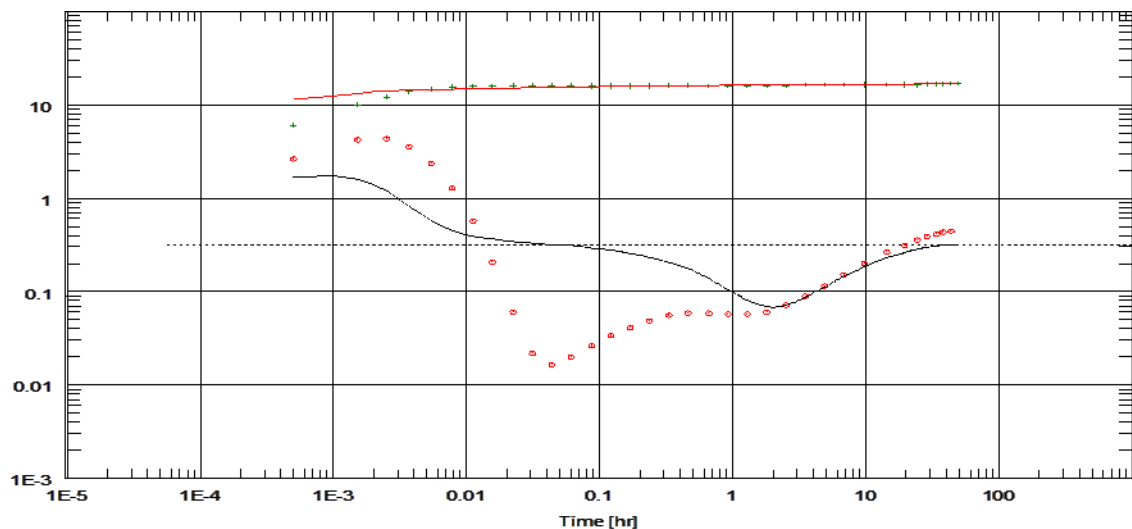


Fig.4.5. Drawdown test {pressure (psi) vs. time}.

4.3. Build-up Test

For the drawdown test, the following data is needed: $C = 0.0118 \text{ bbl/psi}$, $\text{skin} = 2.1$, reservoir and boundary characteristics, $P_i = 7044.08 \text{ psi}$, $Kh = 85800 \text{ md.ft}$, $K = 96.4 \text{ md}$, $\Omega = 0.00577$ and $\Lambda = 1.25 \text{E-}7$. Fig.4.6 displays the build-up test result.

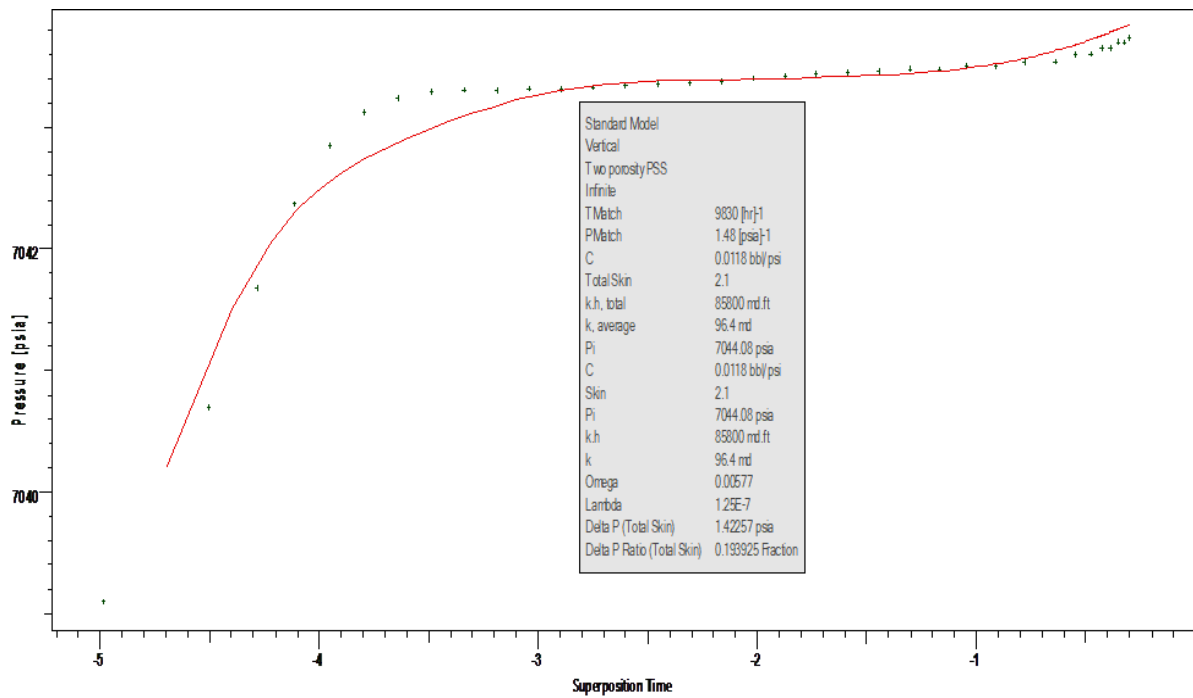


Fig.4.6. Semi-log plot: pressure (psi) vs Superposition time.

The drawdown test revealed less agreement with the reservoir properties that were reported. A high rate of matching between production pressure and time, however, has been recorded by the build-up test. This indicates high match reservoir characterizations since there is little difference between matrix and fracture permeability. A confined homogeneous reservoir with a low fracture contribution to storage and flow capacity would appear to exhibit this behaviour (Tawfeeq Y et al. 2020).

The complex characteristics of carbonate reservoirs, coupled with the limited testing duration, enable well-tested data to adjust closely with various models. The well can also be productively modeled using a dual-porosity approach with a constant-pressure boundary, as illustrated in Figure 8. However, the absence of evidence for sealing boundaries near the well, as indicated on the geological map, challenges this interpretation as it does not account for potential reservoir system closure. It is significant to note that both double-porosity and triple-porosity models provide comparable estimates for fracture system permeability. Regardless, while the double-porosity interpretation emphasizes reservoir quantification, the triple-porosity model suggests an unlimited well drainage area. This distinction carries important

implications for reservoir evaluation and management. The Odeh model, as a homogeneous reservoir with the entire system permeability, was not applicable since the fracture in this field obeys type 1, in which fractures provide the essential reservoir porosity and permeability, which is why the match did not look clear in (Figs. 4.2 and 4.4).

CHAPTER FIVE

CONCLUSIONS AND FUTURE WORKS

5.1. Conclusions

Evaluation of a well-test model for naturally fractured reservoirs with vuggy carbonate of the Ekofisk oil field in Norway will make up our sizeable additional reservoir well-testing has been utilized to determine the sort of natural fracture in reservoirs with dual or triple porous and permeable media.

1. Thus, full-type curve matching along derivatives is a valuable tool for all naturally fractured reservoir types. The classical and Odeh's models may be appropriate for these settings.
2. However, the semi-log straight line ought to be used with caution since wellbore storage along boundary effects in a homogenous bounded reservoir produces the same shape.
3. Even if the derivative method type curves do not match well, semi-log can offer an accurate calculation of permeability.
4. Conventional models applied to commercial applications showed an inability to examine some of the more complex behaviors seen in the case study, and the same behavior might be explained using different approaches. The Odeh model, as a homogeneous reservoir with the entire system permeability, was not essential since the fracture in this field obeys type 1, which provides the reservoir's essential permeability and porosity. As a result, the match did not appear evident in Fig.4.2.

5.2. Recommendations

We recommend using the two-grid scheme – the coarse and finer grids in any research that deals with WT in NFR. Also, we recommend that future researchers study how to differentiate and locate the true two-straight lines occurs in the dual-porosity model.

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