Primary and Secondary Recovery of Gelama Merah Field

Mohammad Aqasha Iman
Universiti Teknologi PETRONAS
Seri Iskandar, Perak, Malaysia
mohammad19000804@utp.edu.my

Faiq Hafiy Rozeman
Universiti Teknologi PETRONAS
Seri Iskandar, Perak, Malaysia
faiq_19000904@utp.edu.my

Mohd.Razie Jaafar
Universiti Teknologi PETRONAS
Seri Iskandar, Perak, Malaysia
mohd.razie_20000950@utp.edu.my

Muhammad Suhayl Aiman Bin Saiful Adzwar
Universiti Teknologi PETRONAS
Seri Iskandar, Perak, Malaysia
suhayl_18001068@utp.edu.my

Pg Mohd Ikhwan Haziq bin Agku Jali
Universiti Teknologi PETRONAS
Seri Iskandar, Perak, Malaysia
pg_19000764@utp.edu.my

Myra Batrisyia Baha'Uddin
Universiti Teknologi PETRONAS
Seri Iskandar, Perak, Malaysia
myra_19000410@utp.edu.my

Juhairi Aris Bin Muhamad Shuhili
Department of Business and Management, Universiti Teknologi Mara Perak Branch Tapah Campus, 35400 Tapah Road, Perak
juhairiaris@gmail.com

Muhammad Adidinizar Bin Zia Ahmad Kusairee
Department of Business and Management, Universiti Teknologi Mara Perak Branch Tapah Campus, 35400 Tapah Road, Perak
adidi627@uitm.edu.my

Rosli Yakop
School of Engineering, Asia Pacific University of Technology and Innovation (APU),
Kuala Lumpur, Malaysia
rosli.yusop@apu.edu.my

***Abstract* — This study investigated and optimized recovery methods for the Gelama Merah Field, aiming to maximize oil production. While initial reliance on natural pressure and artificial lift (primary methods) facilitated initial production, declining rates necessitated exploration of secondary methods like water and gas injection. Through simulations and analysis, optimal production scenarios and injection rates were determined, leading to gas injection being identified as the most effective solution due to its capability in addressing reservoir challenges. Despite higher upfront costs, gas injection demonstrated its economic viability by yielding significant oil recovery and ensuring project profitability. This study highlights the crucial role of tailored recovery strategies in maximizing hydrocarbon extraction from mature fields like Gelama Merah, where gas injection emerges as a promising solution for sustaining production and extending the field's lifespan.**

Keywords: Primary Recovery, Secondary Recovery, Gas Lift

I. INTRODUCTION

The global energy industry relies heavily on extracting hydrocarbons from reservoirs. As production rates decline and field life shortens, there is a constant need for improved recovery techniques. This paper focuses on the Gelama Merah Field, a prime example was applying and optimizing primary and secondary recovery methods can be highly impactful. We aim to delve into these techniques, evaluate their effectiveness in this specific field, and contribute to the ongoing discussion on advancements in oil recovery technologies.

Nestled within Malaysia's prolific hydrocarbon basin, the Gelama Merah Field boasts a complex geological history, evident in its intricate structural features and varied reservoir compositions. Initially, these favorable characteristics, coupled with its strategic location, led to significant production. However, like many mature fields, Gelama Merah now faces the twin challenges of diminishing output and rising operational costs, necessitating a critical reevaluation of its recovery methods.

Initially, the Gelama Merah Field relied on natural pressure and artificial lift mechanisms, like pumps, for primary recovery. These methods, while successful in generating initial production, have limitations in maximizing the total recoverable oil. Therefore, the focus has shifted towards secondary recovery methods, such as water or gas injection, to potentially revitalize production and extend the field's lifespan.

Given this context, it becomes crucial to investigate and optimize both primary and secondary recovery strategies specifically tailored to the Gelama Merah Field's unique geological and operational characteristics. By drawing upon the expertise of reservoir engineering, drilling engineering, geophysics, and production optimization, this study aims to shed light on key considerations and best practices for improving oil recovery efficiency within this vital hydrocarbon resource.

II. LITERATURE REVIEW

A. Primary Recovery Technique

The initial stage of oil production, primary recovery, plays a critical role in unlocking the potential of a reservoir. During this phase, the focus lies on utilizing natural reservoir pressure to drive oil from its rock formations towards production wells. However, as pressure inevitably declines over time, artificial lift mechanisms are often employed to supplement the natural flow and maintain production. Common examples of these mechanisms include gas lift and rod pumps.

Optimizing primary recovery hinges on the strategic placement of wells, a concept emphasized by (Carrasco & Trillo, 2015). This strategy, known as "sweet spotting", involves meticulously analyzing key reservoir properties like porosity, permeability, and water saturation. Porosity refers to the void space within the rock formation that can store fluids, while permeability reflects the ease with which fluids can flow through these interconnected spaces. Water saturation indicates the percentage of pore space occupied by water, influencing the amount of oil available for extraction.

By integrating seismic attributes, which provide insights into the subsurface structure and properties, and historical production data, operators can create a comprehensive picture of the reservoir. This multi-dimensional approach is crucial for identifying "sweet spots", the most favorable zones within the reservoir characterized by high porosity, permeability, and lower water saturation.

Leveraging the knowledge gained through "sweet spotting", operators can make informed decisions regarding drilling locations and well trajectories. This ensures that wells are placed in the most advantageous locations to maximize initial oil production rates and effectively tap into the natural reservoir pressure.

While primary recovery is essential for initiating oil extraction, its inherent limitations, such as declining pressure and limited oil recovery, necessitate the exploration of secondary recovery methods to further enhance production and extend the field's life cycle.

B. Primary Recovery with Gas Lift

Primary recovery with gas lift represents an augmentation of traditional primary recovery methods, leveraging gas injection to enhance oil extraction from the reservoir. Gas lift technology is employed to increase the gas-oil ratio (GOR) within the wellbore, reducing the overall fluid density and facilitating oil flow to the surface.

In the context of the Gelama Merah Field, primary recovery with gas lift offers a viable solution for overcoming reservoir challenges and maximizing oil recovery. Simulation and analysis, as conducted in this study, enable the identification of optimal operating conditions and production scenarios, ultimately contributing to the field's sustainable development and longevity.

C. Secondary Recovery Strategies (Water Injection)

Secondary recovery strategies are implemented after primary recovery methods to further enhance oil extraction from reservoirs. These methods typically involve injecting fluids such as water or gas into the reservoir to maintain pressure and displace additional oil towards production wells. Secondary recovery techniques are crucial for maximizing oil recovery, especially in mature fields where natural pressure depletion has occurred. Low Salinity water (LSW) flooding has gained great attention over the years as a promising enhanced oil recovery (EOR) technique with its superior performance as compared to high salinity water injection (Belhaj, Singh, & Sarma, 2022).

Water injection is a widely used secondary recovery method aimed at maintaining reservoir pressure and displacing remaining oil towards production wells. (Ghafri, Mandhari, Aamri, & Zaabi, 2022) emphasize the dual role of water injection in mitigating the decline in reservoir pressure and optimize the process of sweeping oil towards production wells. The injected water acts as a driving force, pushing oil towards the wellbore and facilitating its recovery. Successful water injection strategies require careful consideration of factors such as injection rate, well placement, and reservoir permeability to optimize oil recovery efficiency.

D. Secondary Recovery Strategies (Gas Injection)

Gas injection, a cornerstone of secondary recovery techniques, plays a crucial role in revitalizing mature oil fields. This method involves the strategic injection of gases like carbon dioxide (CO_2) or natural gas into the reservoir to enhance oil displacement towards production wells. The injected gas propagation through the reservoir is governed by several factors such as the pressure gradient due to injection, the natural density variation between the reservoir fluids, fluid diffusion and dispersion, gas dissolution, mineralization and adsorption (AlAklubi & Khafji, 2024). As highlighted by (Duiveman, Herwin, & Grivot, 2005), gas injection offers several advantages:

- Improved Sweep Efficiency: Gas, with its lower viscosity and higher mobility compared to oil, can access previously unswept zones within the reservoir, displacing residual oil trapped in rock formations. This translates to a more efficient sweep, maximizing the amount of oil recovered.
- Enhanced Oil Displacement: Beyond sweep efficiency, gas injection also facilitates oil displacement from pore spaces through mechanisms like swelling with CO_2 injection. This increased mobility allows oil to flow more readily towards production wells, further enhancing recovery.
- Suitability for Mature Fields: Compared to water injection, gas injection can prove particularly effective in mature fields where factors like high water saturation or unfavorable mobility ratios might hinder water's effectiveness. Gas, with its unique properties, can overcome these challenges and unlock additional oil reserves.

However, the decision to utilize gas injection requires careful consideration of various factors:

- Reservoir Properties: Geological characteristics like porosity, permeability, and heterogeneity significantly impact the effectiveness of gas injection. Understanding these properties is crucial for designing and optimizing the injection process for each specific reservoir.
- Mobility Ratios: The mobility ratio compares the ease of gas flow through the rock compared to oil. Unfavorable ratios, where gas flows significantly faster than oil, can lead to channeling and bypassing oil, ultimately hindering recovery. Selecting the appropriate gas type and injection strategy is essential to ensure a favorable mobility ratio and efficient displacement.

- Economic Feasibility: Like any other recovery method, economic considerations are paramount. Costs associated with gas acquisition, injection infrastructure, and operations need to be weighed against the projected increase in oil production to ensure the project's economic viability.

E. Economic Considerations

It is very important to conduct economic evaluations when implementing secondary recovery strategies. Factors such as capital expenditure, operational costs, and incremental oil recovery need to be carefully assessed to determine the overall viability and profitability of secondary recovery projects. Economic evaluations help operators make informed decisions about the selection of recovery methods and optimize investment decisions to maximize returns.

F. Technological Advances

Advances in reservoir engineering and simulation tools have revolutionized the optimization of recovery techniques. Software platforms like Petrel enable sophisticated reservoir modeling and scenario analysis. These tools empower engineers to simulate various production scenarios, optimize well placement, and assess the performance of recovery methods under different operating conditions.

III. BACKGROUND

A. Primary Production

During the primary recovery phase, well placement played a crucial role in maximizing oil extraction from the Gelama Merah Field. Approximately 25 wells were strategically distributed throughout the field, targeting "sweet spots" identified based on three key reservoir properties: porosity, permeability, and water saturation. According to (Carrasco & Trillo, 2015), the integration of the sweet-spot distribution, seismic attributes, historical oil production data, and insights from petroleum system studies can significantly improve the identification and evaluation of potential hydrocarbon reservoirs. This multi-faceted approach provides a more comprehensive understanding of the subsurface, leading to more informed decisions about exploration and development activities.

To optimize well placement and identify the most productive locations, oil production was simulated using Petrel software for a 20-year period (2023-2043). The simulation initially included 25 wells, aiming to select the top 5 performers based on their oil recovery contribution. The simulation results identified wells GM-T, GM-O, GM-K, GM-P, and GM-I as the most productive, and these were subsequently chosen as the primary production wells for the project. Additionally, the simulation estimated the field's STOIIP (Stock Tank Original Oil In Place) to be 118 million stock tank barrels.

Primary recovery relies on the natural pressure differential within the reservoir to drive hydrocarbons through porous rock formations towards the production well. This passive process requires no intervention in the reservoir itself. However, when natural pressure declines, artificial lift methods, such as gas lift, can be employed. Gas lift injects external, high-pressure gas into the well, increasing the gas-oil ratio (GOR). This lighter mixture reduces the overall fluid density and facilitates its movement towards the surface, ultimately enhancing oil recovery.

B. Secondary Production

Beyond primary recovery, secondary methods like water and gas injection offer a significant opportunity to extend the life of an oil field. By strategically placing injection wells, these fluids can serve a dual purpose. Firstly, maintaining reservoir pressure, as oil is extracted during primary recovery, the natural pressure within the reservoir declines, hindering further production. Injecting fluids helps replenish the pressure, allowing for continued flow of oil towards production wells. Secondly, pushing remaining oil towards production wells. The injected fluids act as a driving force, pushing the remaining oil within the reservoir towards the production wells. This displacement process effectively sweeps previously unrecovered oil towards the wellbore, leading to increased oil recovery.

However, implementing secondary recovery involves drilling additional wells, increasing capital expenditure. Therefore, the recovered oil needs to justify these costs, making careful economic evaluation essential. This evaluation considers the projected increase in oil against the cost and complexity of managing injection processes and potential environmental impacts. Ultimately, successful secondary recovery relies on ensuring the additional oil recovered outweighs the associated investment and ensures the project's economic viability.

IV. RESULTS & DISCUSSION

A. Primary Production

1) Simulated Annual Production of Primary Recovery

During primary production, various trials were conducted to investigate the impact of different bottomhole pressures and oil production rates on the cumulative oil production. The results of these trials are presented as follows:

Case	1	2	3	4
Bottomhole pressure (psia)	1200	1200	1200	1000
Oil production rate (bbl/d)	1000	1500	2000	2000
Cumulative oil production (MMSTB)	9.2	9.2	9.2	11.3

Table 1: Result for primary production

Among the four primary production scenarios tested, case 4 emerged as the optimal choice. This case resulted in the highest cumulative oil production of 11.3 MMSTB, alongside a bottomhole pressure of 1000 psia and an oil production rate of 2000 bbl/d. Therefore, based on its superior cumulative oil production, case 4 was selected as the most effective primary production strategy.

2) Simulated Annual Production of Primary Recovery with Gas Lift

On the other hand, gas lift technology was implemented after primary recovery to further enhance oil extraction from the reservoir by increasing the gas volume. This decision was prompted by the realization, based on previous simulated annual production data, that wells were depleting prematurely. The following section presents the results of primary recovery with the integration of gas lift.

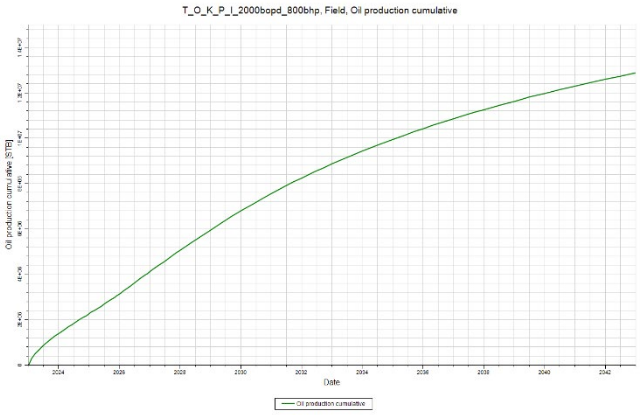

Figure 1: Simulated primary production with gas lift.

Bottomhole pressure (psia)	Oil production rate (bbl/d)	Cumulative oil production (MMSTB)
800	2000	12.9

Table 2: Result for primary production with gas lift

The production engineer employed nodal analysis to analyze the well's performance. This analysis utilized Inflow Performance Relationship (IPR) and Vertical Lift Performance (VLP) curves to identify the operating point, represented by the intersection point of these curves. This point defines the minimum bottomhole pressure (BHP) required to sustain a specific oil production rate while accounting for the well's vertical flow resistance. Based on this analysis, the optimal operating conditions with gas lift were determined to be for bottomhole pressure (BHP) is 800 psia, oil production rate is 2000 bbl/d and cumulative oil production with gas lift is 12.9 MMSTB. Therefore, nodal analysis provided a data-driven approach to establish the most efficient operating conditions for the well with gas lift, maximizing oil recovery while maintaining a sustainable bottomhole pressure.

B. Secondary Production

1) Water Injection

Having achieved a cumulative oil production of 11.3 MMSTB (9.6% recovery factor) through primary recovery and 12.9 MMSTB (10.9% recovery factor) with the addition of gas lift, the decision was made to implement water injection as the next step to further enhance oil recovery. This method involved the implementation of 10 water injection wells throughout the reservoir.

The injection commenced in November 2031, a strategically chosen date coinciding with the reservoir pressure reaching the bubble point pressure. This timing proved advantageous as the oil's PVT properties, particularly its viscosity, become most favorable for displacement by water at the bubble point. In this state, the oil exhibits a significantly lower viscosity, making it easier for the injected water to displace the remaining oil and improve recovery efficiency.

$$M = \frac{\left(\frac{k'_{rw}}{\mu_w}\right)}{\left(\frac{k'_{ro}}{\mu_o}\right)}$$

Figure 2: Mobility Ratio Equation

First and foremost, the mobility ratio was calculated by using Equation 1 formula where the value obtained at 6.8 which was very unfavorable for displacement. This signifies that water will encounter greater resistance compared to oil when flowing through the reservoir rock. To address this challenge, a Voidage Replacement Ratio (VRR) exceeding 1 was implemented. This strategy involves injecting more water than the volume of fluids produced, aiming to overcome the unfavorable displacement characteristics and enhance the efficiency of sweeping oil towards production wells.

In the water injection phase, various scenarios were explored to identify the optimal injection rate that would maximize oil recovery. These scenarios involved experimenting with different water injection rates.

Case	1	2	3	4
BHP (psia)	800	800	800	800
Oil Rate (STB/d)	2000	2000	2000	2000
Injection Rate (MSTB/d)	10	15	20	25
Cum. Water Injection (MMSTB)	474.8	712.2	949.6	1187
Cum. Oil Production (MMSTB)	20.5	22.2	23.1	23.8

Table 3: Result for water injection with different injection rate

Through extensive testing, case 2 emerged as the most effective water injection scenario, yielding a cumulative oil recovery of 22.2 MMSTB, exceeding the primary recovery volume. Cases 3 and 4, despite offering higher oil production, were ultimately disregarded due to exceeding the reservoir's fracture pressure with their respective injection rates of 20 MSTB/d and 25 MSTB/d.

Additionally, trials were conducted to investigate the potential impact of different injection well locations on oil recovery. The results of these trials will be presented in the following section.

Table 4: Result for water injection with different injection wells' location

Location	Intermediate to producer	Further to producer
Water Injection Cumulative (MMSTB)	712.2	427.3
Oil Production Cumulative (MMSTB)	22.2	20.3

While exploring the impact of different injector well locations was not fruitful in further enhancing oil recovery, the project retained the initial injection well configuration that yielded the highest cumulative oil production of 22.2 MMSTB.

However, despite the increased oil production compared to primary recovery, a crucial economic evaluation revealed that the Net Present Value (NPV) of the primary production scenario was higher than that of the water injection scenario. This suggests that the additional costs associated with water injection, such as drilling and maintaining injection wells, may not be fully recouped by the incremental oil recovered.

2) Gas Injection

Given the limitations of water injection, gas injection was deemed a more suitable secondary recovery method. 5 gas injection wells were strategically distributed throughout the field, and two scenarios with varying injection rates were evaluated to identify the optimal approach.

Case	1	2
BHP (psia)	800	800
Oil Rate (STB/d)	2000	2000
Injection Rate (MMSCF/d)	50	100
Cum. Gas Injection (BSCF)	1187	2374
Cum. Oil Production (MMSTB)	18.8	22.5

Table 5: Result for gas injection with different injection rate

Following an evaluation of two gas injection scenarios, case 2 emerged as the optimal choice. This case, utilizing an injection rate of 100 MMSCF/d, yielded a superior outcome with a cumulative oil production of 22.5 MMSTB.

$$M = \frac{\left(\frac{k'_{rg}}{\mu_g}\right)}{\left(\frac{k'_{ro}}{\mu_o}\right)}$$

Figure 3: Formula for mobility ratio (gas)

While plain gas injection demonstrably improves microscopic sweep efficiency, primarily by increasing the Capillary Number (Nc), it often suffers from a limited volumetric sweep. This limitation stems from the relatively low viscosity of the injected gas, leading to an unfavorable mobility ratio (M). This ratio, in turn, plays a critical role in determining the volumetric sweep, or the overall volume of the reservoir effectively contacted by the injected gas (Samad, Ahmed, Al-Dayyni, & Kalam, 2013).

The calculated mobility ratio for gas injection, as determined using the formula outlined in Equation 3, yielded an adverse value of 155.6. This implies that gas will encounter notably higher resistance than oil while traversing through the reservoir rock. To tackle this obstacle, a Voidage Replacement Ratio (VRR) greater than 1 was implemented. This approach entails injecting a larger volume of gas than the fluids produced, with the goal of mitigating the unfavorable displacement characteristics and improving the efficacy of sweeping oil towards production wells.

V. CONCLUSION

This study comprehensively evaluated primary and secondary recovery methods for the Gelama Merah Field. Primary production achieved a cumulative oil recovery of 11.3 MMSTB, which increased to 12.9 MMSTB with the implementation of gas lift. This translates to respective recovery factors of 9.6% and 10.9%.

Secondary recovery explored both water injection and gas injection strategies. Water injection, with an injection rate of 15 MSTB/day, successfully yielded an additional 10 MMSTB of oil, bringing the cumulative recovery to 22.3 MMSTB and the recovery factor to 18.8%. However, a critical economic analysis revealed that the additional costs associated with water injection, such as drilling and maintaining 10 new wells, outweighed the incremental oil revenue.

Therefore, the project transitioned to gas injection as the preferred secondary recovery method. Utilizing an injection rate of 100 MMSCF/day, gas injection successfully recovered 22.5 MMSTB of oil, pushing the recovery factor to 19.1%. This approach not only yielded greater oil recovery compared to water injection but also proved economically viable, as the recovered oil effectively covered the associated costs.

In conclusion, gas injection emerged as the optimal secondary recovery strategy for the Gelama Merah Field, balancing both technical and economic considerations. This method not only delivered superior oil recovery but also ensured project profitability.

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