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Effect of Water Injection Pressure Maintenance Methods on Optimum Marginal Oil Field Development

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ABSTRACT

This study investigated the chemistry entrepreneurial opportunities chemistry students in colleges of education can explore to better their career and help build entrepreneurial attitude within the education space. The study, which was carried out in two colleges of education in Bauchi state, adopted the descriptive survey design. A total of 104 students randomly selected from 100, 200 and 300 levels of chemistry education programme fully participated in the study. Well-developed closed-ended students' questionnaire (SQ1) was used to obtain information from respondents. Data obtained were analysed using frequencies and percentages in order to answer the research questions posed in the study.

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INTRODUCTION

In the oil and gas industry, pressure maintenance in reservoirs is critical for enhancing the production and economic viability of marginal oil fields. Marginal fields, which are characterized by their lower reserves, reduced production rates, and economic constraints, face significant challenges in achieving profitability. As a result, maintaining reservoir pressure becomes essential to prolonging the life of the field and optimizing recovery rates. Pressure maintenance methods involve techniques that help sustain or increase the reservoir pressure to ensure continuous oil flow to production wells, thus enhancing oil recovery. Common pressure maintenance methods include water flooding, gas injection (e.g., CO_2 or nitrogen), and the use of other reservoir engineering techniques.

Pressure maintenance is an essential component of reservoir management, particularly in marginal oil fields, where the economic viability of production depends heavily on efficient reservoir pressure maintenance (Horne, 2018). In marginal oil fields, which typically have low production rates, limited reserves, and high operating costs, maintaining reservoir pressure is crucial for extending the productive life of the field and improving recovery factors (Babadagli, 2007). The main pressure maintenance methods include water flooding, gas injection, and artificial lift techniques, each of which has different mechanisms and applications depending on the reservoir's properties and economic considerations (Alvarado and Manrique, 2010).

Water flooding is one of the most widely used methods for pressure maintenance in marginal fields. It involves injecting water into the reservoir to displace oil towards the production wells, thereby maintaining reservoir pressure and improving oil recovery (Tarek, 2012). This method is particularly effective in reservoirs with moderate to high permeability, where the water can efficiently flow through the reservoir and displace oil (Babadagli, 2007). Water flooding, however, can be less efficient in low permeability reservoirs or in cases where there is poor sweep efficiency, leading to early water breakthrough and potential production of water along with oil (Horne, 2018). Moreover, improper management of the water injection rate can cause uneven displacement, which reduces overall recovery efficiency (Tarek, 2012).

Uche and Onuoha in their study (2014) highlight that while water flooding is economically attractive due to relatively low costs compared to other methods, it may require significant monitoring and control measures to optimize the injection process. Factors such as water quality,

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reservoir heterogeneity, and injection well placement play a significant role in the effectiveness of water flooding (Alvarado and Manrique, 2010).

Gas injection is another widely employed pressure maintenance technique, particularly in fields where the use of water flooding is not as effective. Gas injection typically involves injecting gases such as nitrogen or CO_2 into the reservoir to maintain pressure and enhance oil recovery. CO_2 injection is a form of enhanced oil recovery (EOR) that has been shown to be highly effective in reducing the viscosity of oil, improving flow, and displacing oil from the reservoir (Babadagli, 2007). It also offers the advantage of sequestering CO_2, which can help mitigate greenhouse gas emissions in the long run (Alvarado and Manrique, 2010).

According to Babadagli (2007), CO_2 injection significantly increases the oil recovery factor in reservoirs with low mobility oil, often resulting in recovery rates that can exceed the initial estimates when combined with water flooding. However, the implementation of gas injection methods requires substantial infrastructure, including pipelines, compressors, and gas storage facilities (Uche and Onuoha, 2014). Additionally, CO_2 injection may be less effective in very deep reservoirs where the density and phase behavior of CO_2 are less favorable, leading to challenges in maintaining adequate pressure and oil recovery rates (Tarek, 2012).

Each of these pressure maintenance methods has its strengths and weaknesses, depending on the reservoir conditions and economic constraints. Water flooding is relatively low-cost but may be inefficient in reservoirs with high heterogeneity or low permeability (Horne, 2018). Gas injection methods, particularly CO_2, offer significant benefits in terms of enhanced oil recovery and environmental impact reduction but require considerable capital investment (Alvarado and Manrique, 2010). Artificial lift techniques can be used effectively in wells with low natural pressure, but their operational and maintenance costs can be high (Uche and Onuoha, 2014).

According to a study by Alvarado and Manrique (2010), while water flooding remains the most cost-effective and commonly used method for marginal field development, gas injection and artificial lift systems provide significant advantages in specific reservoir conditions. These techniques can be employed in conjunction to optimize production, with gas injection used to maintain pressure and artificial lift applied to enhance oil recovery when natural flow is insufficient (Tarek, 2012).

Given the complexity of reservoir characteristics and the high costs involved in marginal oil field development, understanding and comparing the effectiveness of these pressure maintenance techniques is critical for optimizing production and ensuring economic feasibility. Marginal oil fields face multiple production and economic challenges due to their lower reserves, reduced production potential, and high operating costs. One of the most significant challenges in optimizing production in these fields is maintaining adequate reservoir pressure, which directly affects recovery rates and operational efficiency.

Although several pressure maintenance methods exist, there is limited research on systematically comparing the different methods in the context of marginal oil fields. In particular, the lack of comprehensive studies on the effectiveness, costs, and sustainability of these pressure maintenance techniques leaves operators uncertain about the most suitable method to employ. The diversity in reservoir characteristics, such as permeability, fluid properties, and depth, makes it challenging to universally apply one pressure maintenance technique over another. As a result, there is a need for a comparative study that critically evaluates the pressure maintenance methods and their applicability to marginal oil field development. This research seeks to conduct a comparative study of pressure maintenance methods of water flooding, gas injection, and artificial lift for optimizing the development of marginal oil fields, with a focus on improving recovery rates, reducing costs, and ensuring sustainability.

METHODOLOGY

The research framework establishes the structure of the study and includes the following

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components: compare water injection, gas injection, and hybrid methods, evaluate their efficiency, cost-effectiveness, and environmental impact and identify the most suitable methods for marginal oil fields. The recovery efficiencies of different pressure maintenance techniques were evaluated considering the costs of each technique in a marginal field settings taking into consideration environmental and operational constraints for each method.

Key Focus Areas:

1. Mechanisms and principles of water injection, gas injection, and hybrid methods.
2. Challenges in applying these methods to marginal oil fields.
3. Technological advancements in pressure maintenance techniques.

Gap Identification

Unexplored areas in pressure maintenance studies were determined, particularly for marginal fields. Water injection to maintain pressure and enhance productivity.

Data Collection

The study relies on a combination of primary and secondary data The Primary date includes field data collected from oil companies operating marginal fields and interviews with reservoir engineers and industry experts while secondary data includes published case studies from global oil fields, economic data such as CAPEX and OPEX for pressure maintenance projects and environmental impact data, including water use and carbon emissions.

Comparative Analysis Framework

A framework is developed to compare pressure maintenance methods. This involves evaluation criteria of efficiency (recovery factor, reservoir pressure stabilization, and displacement efficiency), cost-Effectiveness (CAPEX, OPEX, and cost per barrel of recovered oil), suitability (reservoir characteristics like heterogeneity, permeability, and operational feasibility and environmental impact (water usage, greenhouse gas emissions, and regulatory compliance). Each criterion was assigned weights so as to base on its relevance to marginal oil fields.

Simulation and Modelling

Reservoir simulation is employed to predict the performance of pressure maintenance methods under various conditions using Eclipse and Petrel. The simulation scenarios are different injection rates and patterns, varying reservoir conditions (e.g., permeability, oil viscosity) and economic variables such as oil price and operational costs. The outputs are recovery factors, breakthrough times, and sweep efficiencies and long-term reservoir performance under each method.

Using dynamic modelling, numerous scenarios were simulated in accordance with the project's goal after the oil reservoir model had been initialized with the appropriate data. Natural depletion production was anticipated in the initial scenario, often known as the basic case. A total of 19 vertical oil producers were included in the base. Taking into account the characteristics of the reservoir, these wells were completed at various depths. Additionally, the wells were controlled with different liquid rates, ranging from 13,000 to 25,000 stb/day (stock tank barrels per day), and the simulation was conducted for a duration of 20 years.

To assess and compare the effectiveness of different water injection schemes, multiple water injection patterns were evaluated to determine the optimal field development plan that would result in the highest recovery efficiency compared to other options. The following injection patterns were considered in this study:

Five spot patterns:

In this pattern, four peripheral injection wells are positioned around a central production well, forming a square or rectangular shape. To achieve this setup, the reservoir is divided into equal squares, and the distance between the injection wells and the production well is set at 2120 ft. A total of 55 wells were assigned for this scenario, comprising 22 oil producers and 33 water injectors (as shown in Figure 1). All the

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producers' wells are controlled by liquid rate while injector wells are controlled by bottom-hole pressure (bhp). The simulation was conducted over a 20-year period to assess the performance of this pattern.

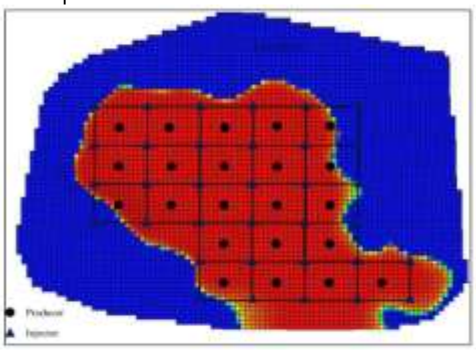

Figure 4: Illustrate the arrangement of production and injection wells in the five-spot pattern scenario.

Inverted five-spot pattern:

In this pattern, a central injection well is surrounded by four peripheral production wells, forming a square or rectangular shape. In order to establish this configuration, the reservoir is divided into uniform squares, with a spacing of 2120 ft between the injection wells and the production well. 50 wells in total, including 27 oil producers and 23 water injectors, were allotted for this particular situation (as illustrated in Figure 5). While bottom-hole pressure (bhp) controls the injector wells, liquid rate controls the producing wells. The simulation was conducted over a period of 20 years to evaluate the effectiveness of this pattern.

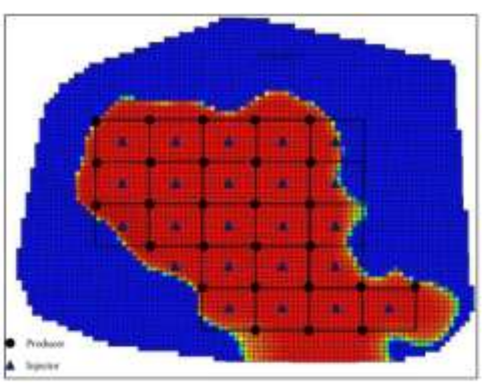

Figure 5: Illustrate the arrangement of production and injection wells in the inverted five-spot pattern scenario.

Direct Line Drive Water Injection:

In this arrangement, the production wells are positioned perpendicular to the injection wells, which are arranged in a straight line or in parallel lines along one direction. 34 wells in all, including 15 oil producers and 19 water injectors, were assigned to this scenario in order to carry out this pattern (Figure 3). Injector wells are controlled by bottom-hole pressure (bhp), whereas production wells are controlled by liquid rate. In order to evaluate the effectiveness and performance of this pattern, a 20-year simulation was run.

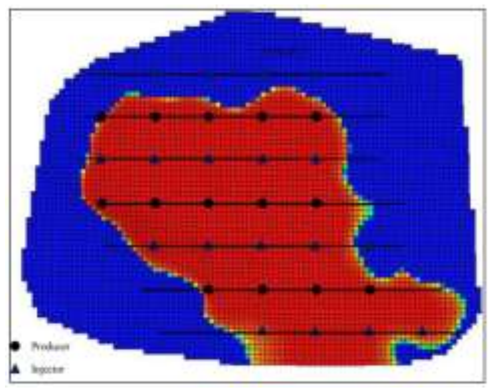

Figure 6: Illustrate the arrangement of production and injection wells in the direct line drive water injection scenario.

Peripheral water injection:

In this pattern, water injection wells are positioned around the periphery or outer edges of the reservoir. The injection wells are strategically located to create a barrier or boundary for the injected water, forcing it to flow towards the central area of the reservoir where the oil-bearing formations are located. A total of 12 injector wells were drilled at the water-oil contact (WOC) to implement this design, and 19 oil producers were strategically placed throughout the reservoir to extract oil (Figure 6). Injector wells are controlled by bottom-hole pressure (bhp), whereas production wells are controlled by liquid rate.

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To assess the effectiveness and efficiency of this pattern, a simulation was run over a 20-year period. It is important to note that in this study, the evaluation focused on achieving the maximum oil recovery for each injection pattern, without considering the optimal number of wells from an economic standpoint. While a particular pattern may yield the highest oil recovery, it may not necessarily be the best scenario when considering the cost and number of wells involved in that specific pattern. The economic feasibility and practical considerations associated with the number of wells used in a pattern should be taken into account to determine the overall viability and profitability of a given approach.

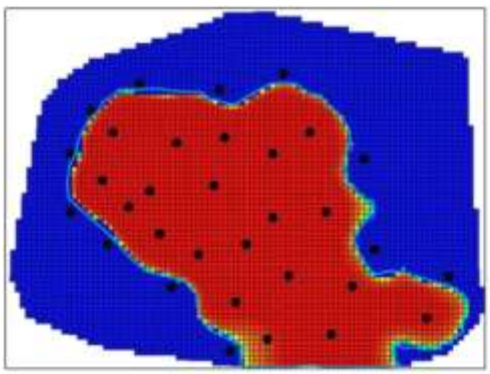

Figure 7: Illustrate the arrangement of production and injection wells in the peripheral water injection scenario.

Case Study Analysis

Real-world case studies are analyzed to validate the findings from the simulations. Water injection and its challenges in high-water-cut reservoirs. Parameters evaluated are ooperational efficiency, cost analysis, and environmental considerations. Using relevant data from a field located in Niger Delta, Nigeria, the ECLIPSE simulator is used to construct an oil reservoir through static modeling. In this specific location, six wells were drilled during exploration and appraisal activities, finding a significant oil deposit in the Paleocene sand and detecting hydrocarbon presence in the Jurassic and Permian layers.

The model is built on a symmetrical grid with dimensions of 68x91x36 in the i, j, and k axes, respectively. The grid's dimensions are 298 feet in the i direction and 300 feet in the j direction. Each cell in the model has a height between 2.5 and 10 feet. Furthermore, a bottom aquifer surrounded the oil reservoir on all sides. A 3D viewer, represented by Figure 5, displays the oil reservoir model. Different porosities and permeabilities are assigned to various reservoir grids to make the study more realistic and applicable. According to Figures 9a and 9b, the permeability values range from 0.25 to 3000 mD, while the porosity values range from 2% to 30%. Table 1 summarizes the reservoir model's attributes.

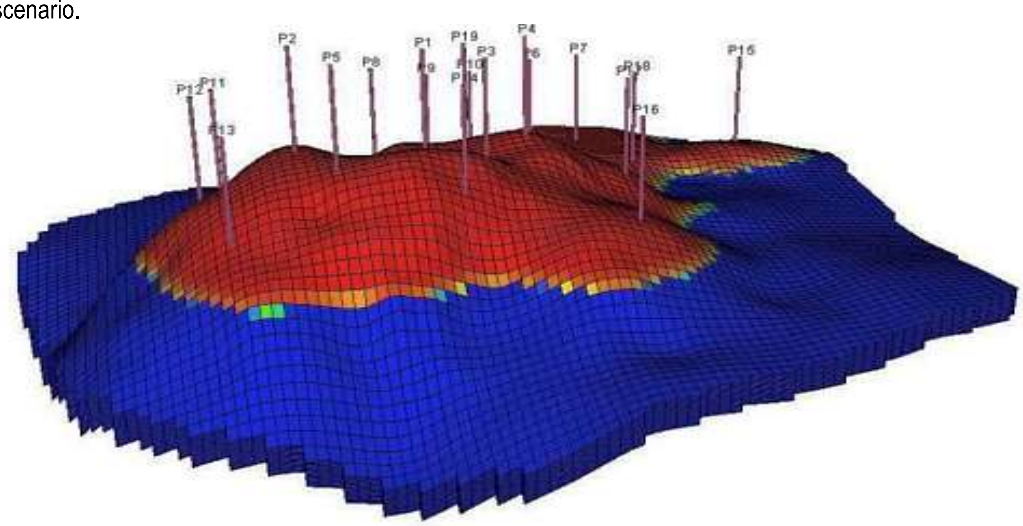

Figure 8: Show a 3D view of reservoir model with aquifer support.

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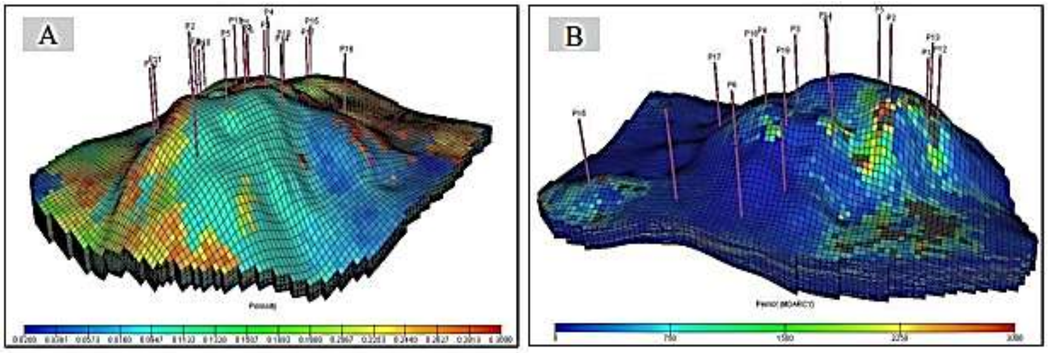

Figure 9: Show the properties distribution of the reservoir model a) porosity b) permeability.

Table 3.1: Model parameters used to construct an oil reservoir.

Properties	Values
Grid Dimension in I, J and K direction	68x91x36
Reservoir pore volume	1521x 10^6 bbl
Water-Oil contact (WOC)	8692 ft
Initial reservoir pressure	3800 psia
Oil, water density	42, 63 Ib/ft^3
Bw, Cw, μ_w	1.01 bbl/STB, 3.3 x10^{-6} psi^{-1}, 0.3 cp
PV compressibility	3.0 x 10^{-6} psi^{-1}
Initial oil in place	338128386 bbl

Dynamic model

After building the static model, several input data are needed to convert the static model into the dynamic model, such as fluid characteristics, initial reservoir condition, and relative permeability. The minimal set of input data required to create the dynamic model is shown in Figure 7. Figures 8 and 9 depict fluid characteristics, relative permeability, and capillary pressure information for the reservoir.

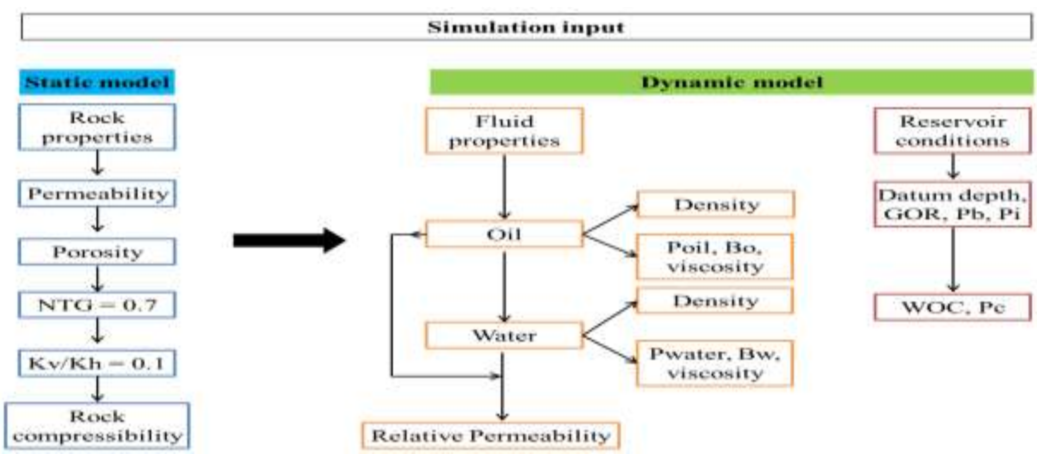

Figure 9: Flow chat show minimum reservoir simulation input data.

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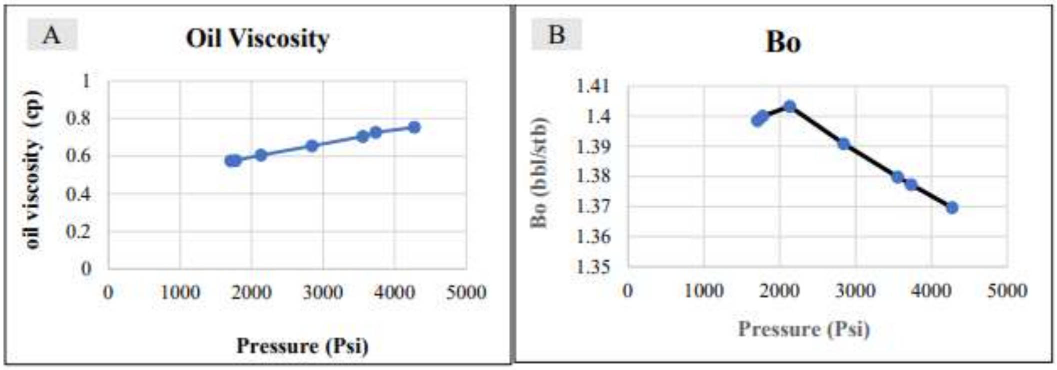

Figure 10: Fluid model used in the reservoir simulation study a) oil viscosity b) oil formation volume factor.

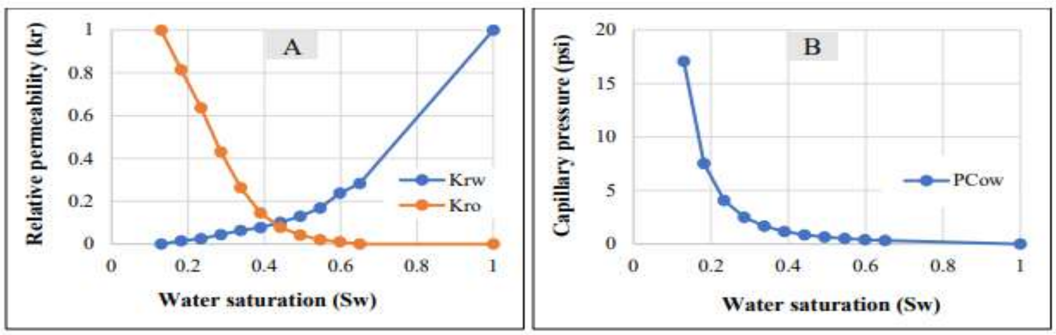

Figure 11: Show a) oil-water relative permeability b) oil-water capillary pressure used in the simulation study

Sensitivity Analysis

Sensitivity analysis was conducted to identify the key factors influencing the performance of pressure maintenance methods. Parameters analyzed are reservoir variables (permeability, porosity, and heterogeneity), operational parameters (injection rates, fluid types, and well placement) and economic factors (oil price fluctuations, CAPEX, and OPEX). Cross-reference simulation outputs and case study findings with historical field data was considered so as to valid the simulation cases. Also, ensured consistency with the industry benchmarks and compared with global best practices in pressure maintenance.

RESULTS

Effect of Water Injection on Pressure

The provided figure 4.1 illustrates the impact of water injection on reservoir pressure over time compared to a base case with no injection. It was observed that n the absence of any pressure maintenance methods (Case_10000), the reservoir pressure declines significantly and consistently over time. This rapid pressure drop is due to continuous hydrocarbon extraction without any compensating fluid injected into the reservoir. It results in lower recovery efficiency and may lead to early depletion. In Case_10000_WINJ, water injection is implemented continuously throughout the reservoir's production life.

This maintains a relatively higher reservoir pressure, slowing the decline and stabilizing pressure levels for a longer period. The effectiveness of water injection in this case demonstrates its ability to compensate for pressure losses and maintain the drive needed to push hydrocarbons toward production wells. In Case_10000_WINJ_2028 (green line), water injection begins after a delay (e.g., starting in

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2028). Initially, the pressure follows a decline similar to the base case, but once injection begins, pressure stabilizes and declines more gradually compared to the base case. This case illustrates how delaying water injection can partially mitigate pressure loss, although it may not be as effective as early intervention.

Continuous water injection (gold line) is the most effective strategy for maintaining reservoir pressure and prolonging reservoir productivity. Delayed injection (green line) helps to recover some pressure stability but is less effective than initiating injection from the start. Thus, it can be seen that without water injection, reservoir pressure declines steeply, leading to inefficient hydrocarbon recovery. Water injection, whether early or delayed, demonstrates its value in sustaining reservoir energy and improving recovery factors.

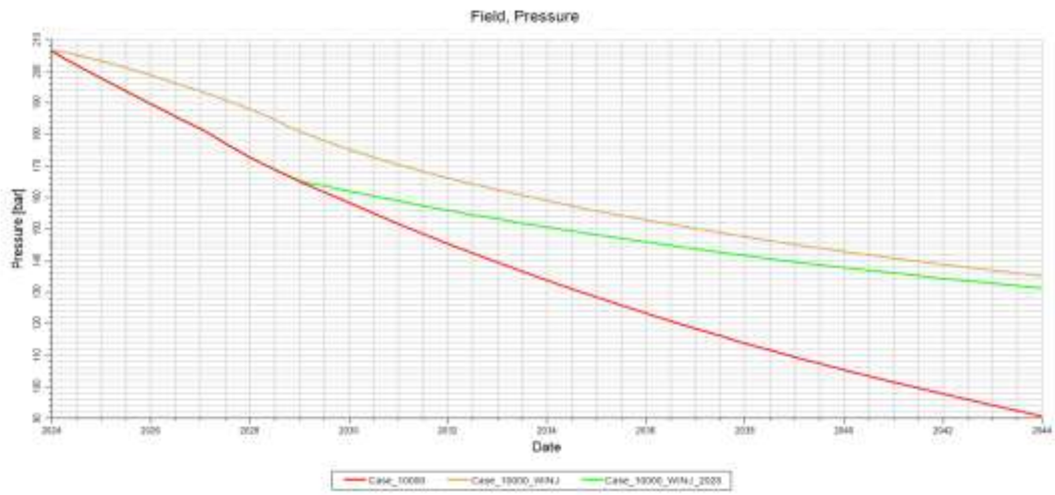

Figure 12: Effect of Water Injection on Pressure

Effect of Water Injection on Cumulative Oil Production

The figure 4.2 illustrates the effect of water injection on the cumulative oil production over time for three different cases. In this scenario, no water injection is applied (base line), leading to a slower and steady increase in cumulative oil production over time. The production reaches lower cumulative levels because the reservoir pressure declines continuously, reducing the energy required to mobilize and produce oil (Tarek, 2012).

This highlights the inefficiency of reservoir production without any pressure maintenance, especially as depletion progresses. Continuous Water Injection (Gold Line - Case_10000_WINJ) from the beginning of the production life showed that cumulative oil production increases significantly compared to the base case, particularly noticeable over the long term. The steady maintenance of reservoir pressure provided by water injection enhances the displacement of oil, improving recovery efficiency and delaying production decline. By sustaining a more efficient drive mechanism, this method ensures that higher cumulative production levels are achieved over the entire production period. Delayed Water Injection (Green Line - Case_10000_WINJ_2028) resulting in cumulative production initially following the trajectory of the base case.

Once water injection is initiated, the rate of cumulative production improves, surpassing the base case but remaining lower than continuous injection. This shows the impact of delayed intervention: while water injection can still enhance recovery, early application is more effective in maximizing cumulative production (Dewan *et al.,* 2022). Continuous water injection leads to the highest cumulative production, maximizing recovery over time. Delayed injection

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offers moderate improvement but is less effective compared to early intervention. Water injection sustains reservoir energy, facilitating more efficient hydrocarbon displacement and recovery. Without injection (base case), reservoir pressure depletes quickly, limiting recovery potential.

Optimization Insight:

Early and sustained water injection (gold line) provides the best results, supporting the importance of timely pressure maintenance strategies.

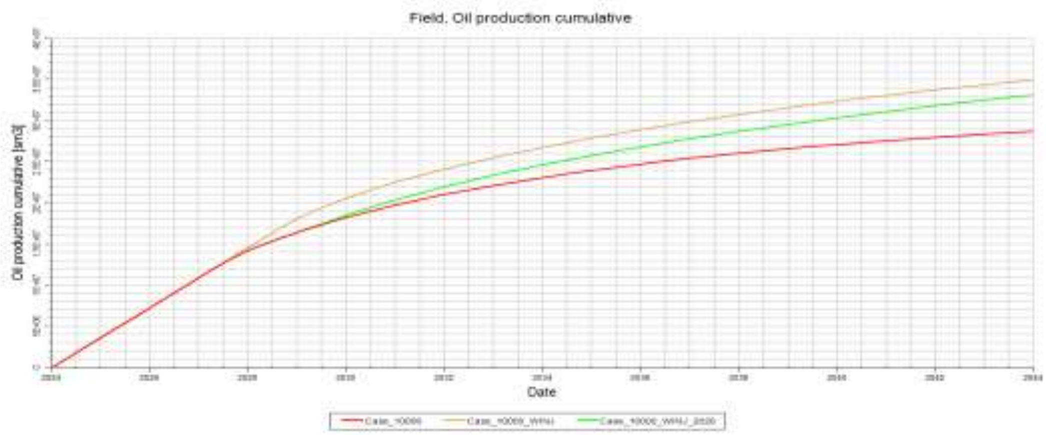

Figure 13: Effect of Water Injection on Cumulative Oil Production

The Figure 12 illustrates the effect of water injection on the oil production rate over time for three scenarios: no injection, continuous injection, and delayed injection. Without water injection (red line), the oil production rate declines significantly over time. The production rate follows a steep, stepwise decline, indicating a rapid depletion of reservoir energy and drive mechanism. This scenario demonstrates the typical production decline curve for reservoirs without any pressure maintenance, leading to inefficient recovery over time.

Continuous water injection (golden line) from the start maintains higher production rates compared to the base case. The production rate declines more gradually, with each step of reduction occurring at a slower pace. By maintaining reservoir pressure, water injection enhances oil displacement and sustains production rates over a longer period. This is the most effective scenario for ensuring stable production and maximizing recovery. In the case of delayed, water injection starts in 2028, leading to an initial decline similar to the base case. After injection begins, the production rate stabilizes and follows a trend closer to continuous injection, though it does not fully recover the initial losses.

Delayed injection improves production rates compared to no injection but is less effective than continuous injection due to the early pressure depletion and loss of recovery potential. The base case without water injection shows the fastest decline in production rates, reflecting the loss of reservoir drive energy. Continuous injection maintains a higher and more stable production rate throughout the production lifecycle. Delayed injection provides moderate improvement but cannot fully compensate for the initial production decline. Early and continuous water injection effectively stabilizes production rates, ensuring a steady flow of oil over time. Delayed injection, while beneficial, results in lower cumulative production rates due to the initial period of unmitigated reservoir pressure loss.

Effect of Water Injection on Gas-Oil Ratio

The figure 15 shows the effect of water injection on the gas-oil ratio (GOR) over time for three cases: no water injection, continuous water injection, and delayed water injection. In the

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absence of water injection (red line), the gas-oil ratio (GOR) increases significantly over time. This rise indicates that reservoir pressure declines rapidly, causing dissolved gas in the oil to come out of solution. As a result, the production becomes increasingly gas-dominated (Dewan *et al.,* 2022). The escalating GOR reflects inefficient reservoir energy and poor oil recovery, as the reservoir transitions to gas-driven flow earlier in the production cycle. When continuous water injection (gold line) is applied, the GOR remains relatively stable and low throughout the production period. Water injection maintains reservoir pressure, reducing the tendency of gas to evolve from the oil phase. This preserves the solution gas drive mechanism for a longer time (Horne, 2018). The stability in GOR indicates that water injection successfully supports oil production while minimizing gas breakthrough and maintaining reservoir energy

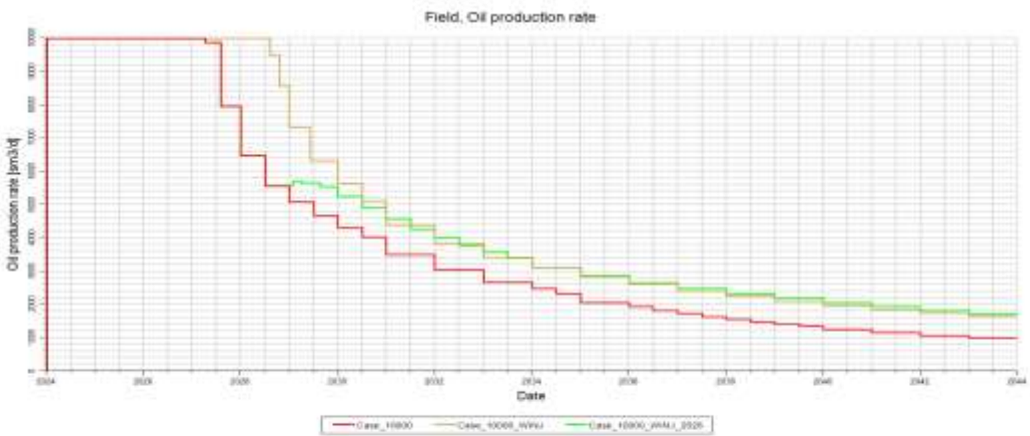

Figure 14: Effect of Water Injection on Oil Production Rate

For delayed water injection (green line starting in 2028), there is an initial rise in GOR similar to the base case due to early pressure depletion. Once water injection begins, the GOR stabilizes at a lower level, similar to the continuous injection case. However, the earlier pressure drop before injection begins results in slightly higher GOR levels compared to continuous injection.

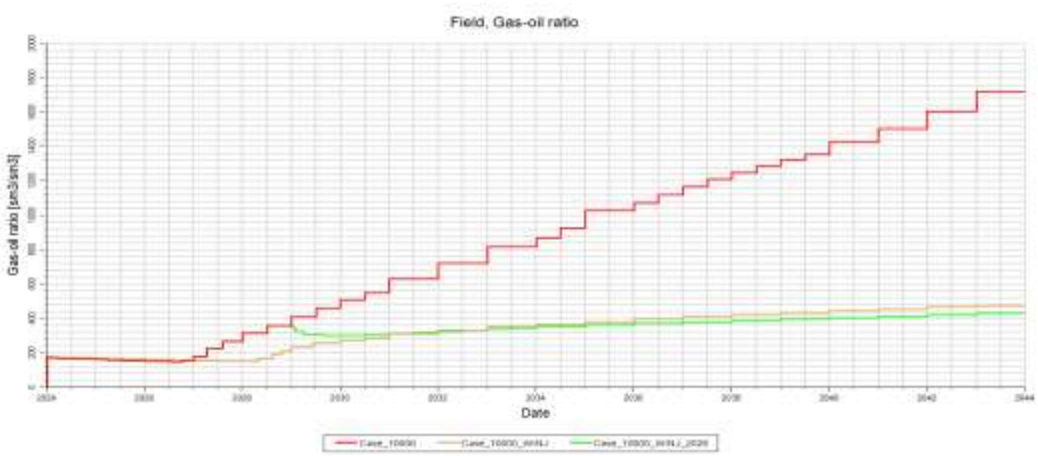

Figure 15: Effect of Water Injection on Gas-Oil Ratio

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CONCLUSION

This study shows that continuous water injection is the most effective method for maintaining reservoir pressure, stabilizing production rates, and maximizing cumulative oil recovery. It also revealed that delayed water injection is beneficial but less efficient compared to early and continuous injection due to initial pressure depletion. It further revealed that while gas injection (CO_2 and nitrogen) and hybrid methods (e.g., WAG) are effective, they often involve higher costs and operational complexity, making them less suitable for marginal fields with economic constraints. Water injection offers a cost-effective solution for marginal fields but requires adequate water sourcing and disposal management to minimize environmental impact. Water injection successfully mitigates GOR increases by maintaining reservoir pressure, ensuring more efficient oil recovery compared to the base case.

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