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RESEARCH ARTICLE

Analysis of Enhanced Oil Recovery Based in Well Patterns and Injection Volume using the Continuous CO_2 Injection Method

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Abstract

This study examines how the continuous CO_2 injection method can improve oil recovery based on well patterns and injection volumes. The increase in oil recovery is observed using a number of well pattern scenarios, each with injection volume sensitivity. CMG-GEM is the software used in this study to simulate the different scenarios. A homogeneous reservoir model, grid data, reservoir fluid data, and reservoir data are among the data needed for this study. Four-spot, five-spot, nine-spot well patterns are taken into consideration in this research scenario. For each well pattern` the injection volumes that will subsequently be used as a reference for the injection rate at the injection well are one HCPV, five HCPV, ten HCPV, and twenty HCPV. According to the study's findings, the inverted nine-spot well pattern with an injection volume of twenty HCPV scenario improves oil recovery more than the four-spot, five-spot and nine-spot well patterns.

Keywords: Paper, JGEET, Universitas Islam Riau, Abstract

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1. Introduction

CO_2 flooding is a method of Enhance Oil Recovery (EOR) that involves injecting CO_2 gas into a reservoir to increase oil production. The CO_2 gas reduces the viscosity and density of the oil, creating a homogeneous fluid mixture of CO_2 and oil (Dong, et al, 2019). CO_2 Flooding employs various injection scenarios, including continuous CO_2 injection, Water-Alternating-Gas (WAG), and huff and puff.

Well pattern refers to the configuration or layout of injection and production well within an oil field (Oktaviani, et al, 2020). The well pattern is designed to maximize oil and gas recovery by ensuring that CO_2 injected is distributed evenly.

CO_2 emissions from industrial sources, such as power plants or factories, can be injected into reservoirs to enhance oil production in a field. This method also helps reduce CO_2 emissions released into the atmosphere, which has a positive effect for global warming conditions (Hartono, et al, 2019). After the CO_2 flooding process is completed, the oil reservoir produced through CO_2 injection can serve as a long-term CO_2 reservoir, as the trapped CO_2 gas can remain isolated underground for an extended period.

The objective of the research to be analyzed regarding the use of continuous CO_2 injection method is as follows:

- Analyzing the comparison of oil production based on well pattern scenarios.
- Understanding the relationship between injection volume and oil production.
- Identifying the optimal scenario and calculating recovery factors for well patterns and injection rates to enhance oil recovery.

2. Literature Review

2.1 CO_2 Flooding

EOR method that involves injecting CO_2 into productive layers at a pressure below the formation's fracture pressure. It is crucial to understand the properties of CO_2 during the CO_2 flooding process. Under ambient conditions, CO_2 is a colorless, odorless gas that is approximately 1.5 times heavier than air. The solubility of CO_2 in oil is 2 to 10 times greater than in water (Sugiharto, 2009). Additionally, CO_2 increases the viscosity of water and forms carbonic acid, which is beneficial in shale and carbonate rocks.

Huff and Puff, continuous and WAG (Water Alternating Gas) are three distinct injection strategies or modes of operation for CO_2 EOR. They differ primarily in how CO_2 is injected into the reservoir and how it interacts with the oil. Below is a breakdown of each strategy (Green, et al, 2003).

CO_2 *Continuous.* Continuously injecting CO_2 gas into the reservoir is expected to dissolve the CO_2 in the oil, reducing oil viscosity and increasing reservoir pressure. This method is effective in increasing oil recovery when applied to reservoir with a stable injection system design.

Water Alternating Gas (WAG). The WAG method combines alternating CO_2 and water injection. CO_2 is injected to increase oil mobility, followed by water injections, which helps move the CO_2 and oil to production well (Usman, 2011). This cycle is repeated to increase oil recovery efficiency and reduce the risk of CO_2 short-circuiting.

Huff and Puff. Huff and Puff is a cyclic method that involves injecting CO_2 into a reservoir, followed by a holding period to allow the CO_2 to interact with the oil. After the holding period, the CO_2-affected oil is produced. This

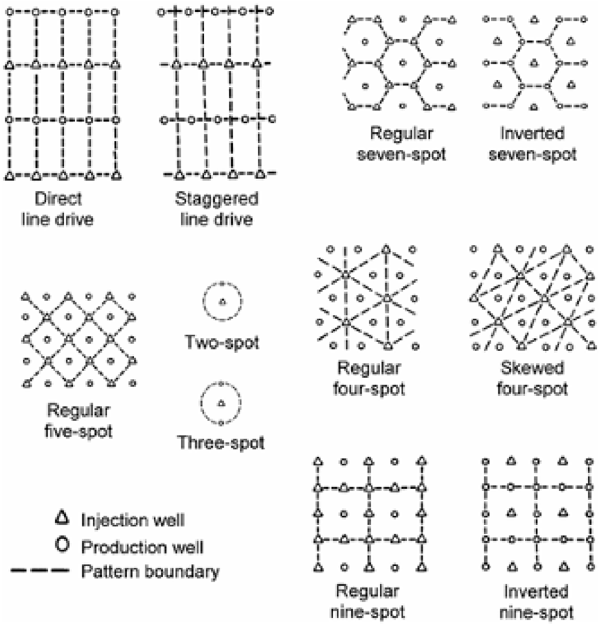


Fig 1. Well Pattern (Lake, 2010)

method is suitable for reservoirs with high viscosity and significant production declines.

2.2 Well Pattern

A well pattern (**Figure 1**) is a pattern or arrangement of production and injection wells in an oil or gas field to optimize production. Based on the location of the production and injection wells and the shape of the well pattern, well pattern areas can be divided into four-spot, five-spot, seven-spot, nine-spot, inverted seven-spot, inverted nine-spot, and linear injection patterns (Liu, et al, 2017).

2.3 Minimum Miscible Pressure (MMP)

The Minimum Miscibility Pressure (MMP) parameter significantly influences the CO_2 flooding process. MMP is the minimum pressure at which the injected gas and oil in the reservoir can mix and form a homogeneous fluid. Typically, the CO_2 MMP is greater than 1400 psia and is influenced by several factors, including reservoir temperature, oil characteristics, and the purity of the CO_2 injected gas.

The determination of this MMP was conducted experimentally using the industry-standard Slim-Tube Test method (Zhang, et al, 2023). Although the Slim-Tube Test is the recognized standard for dynamic MMP determination, it possesses certain limitations. It is highly time-consuming, typically requiring several days per MMP determination. Also, it consumes large volumes of both oil and gas. Furthermore, the interpretation of the resulting is subjective, as it relies on visually identifying the pressure at which the predefined critical point on the recovery vs pressure curve.

2.4 CMG GEM Simulator

GEM Simulator, developed by Computer Modeling Group (CMG), is the software used in this study. GEM is a multidimensional compositional simulator with Equation of State (EOS) that is capable of modeling various important mechanisms in the injection and production of miscible gas. The use of GEM is essential because of the following.

Compositional Modeling. CO_2 flooding operates under high pressure where the gas and oil components continuously transfer mass and change phase properties (density, viscosity, volume). GEM uses EOS such as the Peng-Robinson to accurately calculate the composition and physical properties of the phases (gas, oil, water) at every point in the reservoir. This dynamic calculation is crucial for accurately predicting MMP.

Unlike simpler black-oil simulators that assume fixed composition, GEM accurately tracks the intricate component exchange between the injected CO_2 and the reservoir oil, which is the primary mechanism for oil mobilization during miscible/near-miscible floods.

Diffusion. Models the movement CO_2 of into the oil phase at a molecular level, driven by concentration gradients. This process is vital for calculating the CO_2 induced oil swelling and viscosity reduction.

Dispersion. Models the mixing of fluids on a pore scale due to variations in local flow velocities. Dispersion, coupled with diffusion, collectively determines the degree of mixing between the injected CO_2 and the resident oil, significantly impacting sweep efficiency.

Capillary Pressure. Capillary pressure Pc is the pressure difference between two immiscible fluid phases (e.g., oil and water, CO_2 and oil) across a curved interface within the rock pores. GEM models the initial saturation distribution using capillary pressure restoration. Crucially, Pc must be included because the high solubility of CO_2 in oil dramatically reduces the Interfacial Tension IFT between the phases. A reduction in IFT leads to a significant reduction in Pc which helps overcome the forces trapping residual oil, thus enhancing recovery.

Complex Fluid Flow. GEM solves comprehensive fluid flow equations based on Darcy's Law, extended for multiphase flow through the use of relative permeability Kr and the aforementioned capillary pressure terms. This ensures that the flow rates and distributions of oil, water, and gas are accurately predicted across the reservoir grid.

The ability to perform multi-component miscible simulations with varying gas viscosities and densities, as well as fully implicit calculation options including physical dispersion, makes GEM a very suitable reservoir simulator for this study.

3. Data and Methodology

3.1 Data

This study utilized secondary data, drawing heavily from the CMG model template (gmhg025.dat), which simulates CO_2 injection into an oil reservoir with geochemical effects. Additional supporting data was gathered from literature reviews. **Table 1** and **Table 2** describes reservoir and fluid composition, respectively.

Reservoir model (**Figure 2**) has a grid dimension of 18 x 18 x 8 with a grid block size of 175m x 175m x 25m. The reservoir has 8 layers with a depth range of 2,900 – 3,100 m, the WOC (Water Oil Contact) zone is at a depth of 3,000 m. The reservoir of this model is a carbonate reservoir (dolomite and calcite). **Figure 3** illustrates the relative permeability of the model.

The well patterns used in this study are four-spot pattern, inverted four-spot pattern, five-spot pattern, inverted five-spot pattern, nine-spot pattern, and inverted nine-spot pattern, with variations in total CO_2 injection of 1 HCPV, 2 HCPV, 5 HCPV, 10 HCPV, and 20 HCPV.

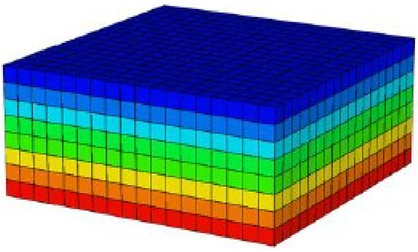


Fig 2. Reservoir Model

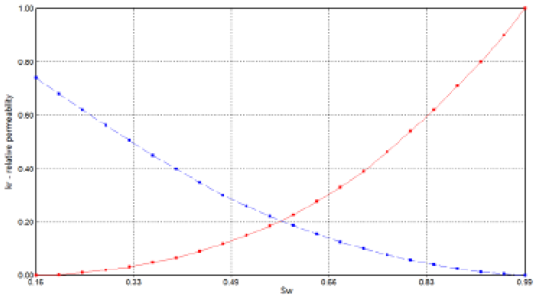


Fig 3. Relative Permeability Curve

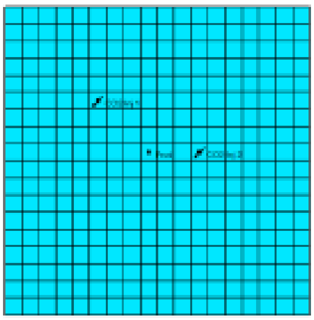


Fig 4. Base Case Model

Table 1. Reservoir Data

Parameter	Value
Reservoir pressure, kPa	34,500
Reservoir temperature, C	76
Permeability, mD	240
Porosity	0.205
Rock Compressibility, 1/kPa	1.e-08
Viscosity, cp	0.361
Density, °API	72.7

Table 2. Reservoir Fluid Composition and Propoerties

Component	Mole Fraction	Specific Gravity	Critical Volume (m^3/kgmole)	Acentric Factor	Mol. Weight (g/gmol)
CO_2	0.053	0.492	0.093	0.225	44.010
N_2-C_1	0.455	0.262	0.099	0.008	16.203
C_2-C_3	0.123	0.482	0.169	0.126	36.237
iC_4-C_7	0.083	0.627	0.309	0.251	71.726
C_8-C_{12}	0.1024	0.741	0.522	0.452	128.835
C_{13}-C_{19}	0.776	0.817	0.777	0.695	212.418
C_{20+}	0.106	0.984	1.115	1.088	472.348

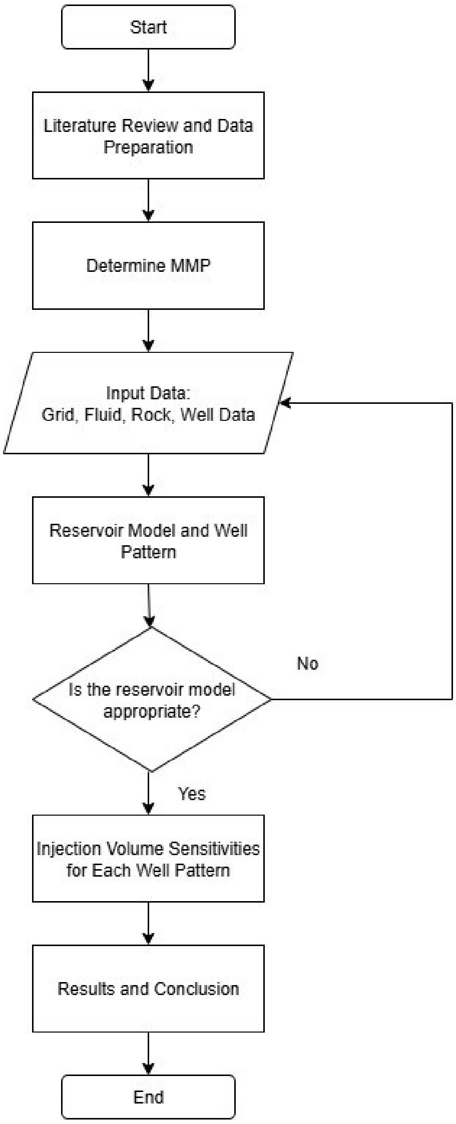


Fig 5. Research Workflow

3.2 Methodology

The base case model consists of two injection wells and one production well, with continuous injection for 25 years. Perforations from the injection wells are performed in layers 3 and 7, while perforations from the production wells are performed in layers 1-4. The injection pressure used is 35,000 kPa with an injection rate of 5,000 m3/day.

To determine how oil recovery increases based on well patterns and injection volumes, simulations were conducted on several well patterns and the sensitivity of injection volumes in each well pattern. The CO_2 injection volumes used in this study were 1 HCPV, 5 HCPV, 10 HCPV, and 20 HCPV injected for 25 years. The bottom hole pressure applied to the production wells was 500 kPa with a production rate of 2000 m3/d, while the maximum bottom hole pressure applied to the injection wells was 35000 kPa and the injection rate adjusted to the number of injection wells and injection volume. The perforation points of the injection wells were in layers 3 and 7. **Figure 5** illustrates the systematic process followed for data collection and analysis.

4. Results and Discussion

4.1 Minimum Miscibility Pressure (MMP)

Minimum Miscibility Pressure (MMP) determination was conducted in this study determining the pressure at which CO_2 mixes with oil. Furthermore, determining the MMP also helps determine the constraints to be applied to injections well.

MMP was calculated using WINPROP software using the Cell-to-Cell simulation calculation method. After conducting the simulation, the MMP was found to be 17,202.7 kPa or approximately 2,495.04 psi.

The injection pressure was used 35,000 kPa, which indicates that injection process is miscible because the injection pressure is greater than MMP.

4.2 Initialization

Model initialization is performed after the reservoir model has been validated. Original Oil in Place (MMSTB) is 123,089,000 m3 and Original Gas in Place (MMSTB) is 18,687,500,000 m3 . Based on the simulation results, the recovery factor or oil recovery from the base case model was found to be 18.827%.

4.3 Injection Rate

The total hydrocarbon pore volume (HCPV) obtained after initialization serves as a reference for determining the injection rate for each well pattern. The injection volume variations used in the simulation are 1 HCPV, 5 HCPV, 10 HCPV, and 20 HCPV. These variations in injection volume will influence the magnitude of the injection rate applied to each well pattern. The primary justification for using unrealistic, high injection volumes in laboratory or simulation studies is to ensure the complete characterization of the displacement process and to isolate the key mechanisms being investigated.

Extremely high injection volumes are used to ensure the displacement process has reached a stable endpoint Sor. This guarantees that the maximum possible oil recovery factor under the simulated conditions is measured. In studies focusing on the long-term effectiveness of the EOR process, injecting a large volume helps to wash out any initial artifacts or numerical dispersion effects that might have occurred during the initial breakthrough phase. High HCPV allows for clear distinction between two different processes by pushing the system to its ultimate potential under each scenario, making the differences easily quantifiable. The example of the injection rates for each well pattern is listed in **Table 3**.

4.4 Four-Spot Pattern

The simulation results (**Figure 6a** and **Table 4**) show that increasing CO_2 injection volume (HCPV) leads to a monotonic but marginal increase in recovery factor. Relative to the base case (18.82%), the recovery factor increases to 19.09% at the highest injection volume, with incremental gains remaining below 0.3%. This indicates that CO_2 injection provides a positive but limited enhancement to oil recovery, suggesting diminishing efficiency at higher injection volumes and highlighting the need for optimization based on technical and economic criteria.

4.5 Five-Spot Pattern

The simulation result is reported in **Figure 6b** and **Table 4** The increase in oil recovery in the five-spot well pattern is still very small, where after injecting 20 HCPV of CO_2, it only yields an increase of 0.42% when compared to the base case, although there is an improvement from the four-spot well pattern.

4.6 Nine-Spot Pattern

In the nine-spot well pattern (**Figure 6c** and **Table 4**) injecting 20 HCPV yielded an increase of 2.2479% when

Table 3. Injection Rate (m3/day) for Different Well Pattern

Injection Volume	Four-Spot	Five-Spot	Nine-Spot	Inverted Five-Spot
1 HCPV	6,248	4,686	2,343	18,744
5 HCPV	31,240	23,430	11,715	93,722
10 HCPV	62,481	46,861	23,430	187,444
20 HCPV	124,962	93,722	46,861	374,888

Table 4. Summary of Recovery Factor and Incremental Recovery Factor

Well Pattern	Injection Volume (HCPV)	Recovery Factor (%)	Incremental Recovery* (%)
Four-Spot	Base Case	18.82	-
	1	18.84	0.01
	5	18.90	0.08
	10	18.97	0.15
	20	19.09	0.26
Five-Spot	Base Case	18.82	-
	1	18.84	0.02
	5	18.95	0.12
	10	19.08	0.26
	20	19.24	0.42
Nine-Spot	Base Case	18.82	-
	1	18.97	0.15
	5	19.50	0.66
	10	20.08	1.17
	20	21.07	2.10
Inverted Four-Spot	Base Case	18.82	-
	1	21.81	2.99
	5	22.19	3.37
	10	22.47	3.64
	20	22.79	3.96
Inverted Five-Spot	Base Case	18.82	-
	1	22.38	3.55
	5	23.13	4.31
	10	23.64	4.82
	20	24.27	5.44
Inverted Nine-Spot	Base Case	18.82	-
	1	23.16	4.33
	5	24.34	5.51
	10	25.49	6.66
	20	26.82	7.99

* Incremental recovery factor from base case

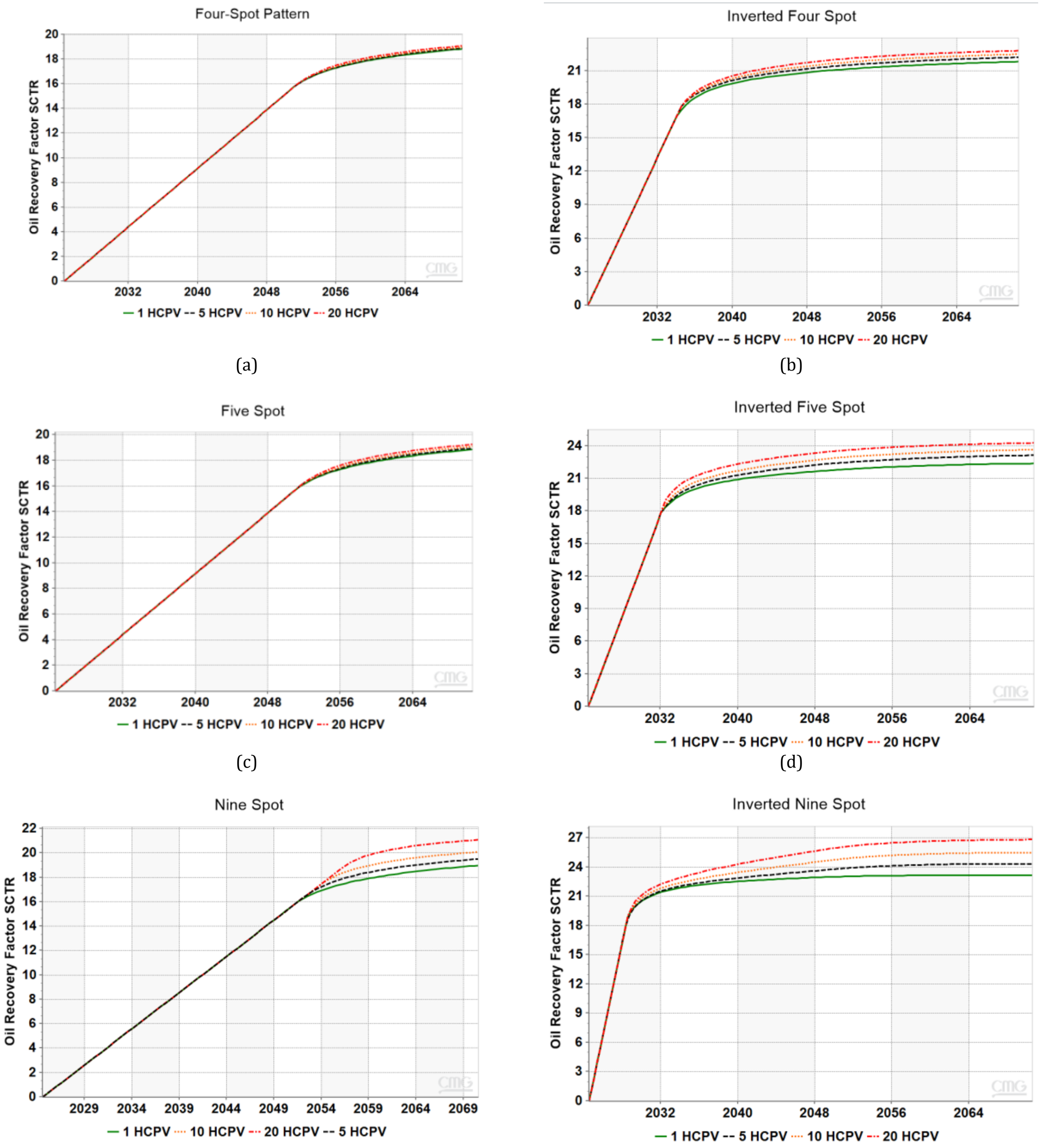
compared to the base case, which is already quite a significant difference when compared to the two previous well patterns.

4.7 Inverted Four-Spot Pattern

For the inverted four-spot well pattern, the simulation results (**Figure 6d** and **Table 4**) demonstrate a substantial improvement in oil recovery with increasing CO_2 injection volume. The recovery factor increases from 18.82% in the base case to 22.79% at the highest injection volume, corresponding to an incremental gain of nearly 4%. This pronounced response indicates that the inverted four-spot configuration provides more effective sweep efficiency and CO_2–oil contact compared to the base case, making the recovery performance significantly more sensitive to injected CO_2 volume.

4.8 Inverted Five-Spot Pattern

For the inverted five-spot well pattern, the simulation results (**Figure 6e** and **Table 4**) show a clear and sustained increase in oil recovery with increasing CO_2 injection volume. The recovery factor rises from 18.82% in the base case to 22.38% at 1 HCPV and continues to increase to 24.27% at 20 HCPV, corresponding to a total incremental



(a) (b) (c) (d) (e) (f)

Fig 6. Oil Recovery Factor for Different Injection Pattern recovery of 5.44%. While additional CO_2 injection beyond 1 HCPV continues to improve recovery, the incremental gains become progressively smaller, indicating a diminishing marginal contribution of injected CO_2 as the injection volume increases.

4.9 Inverted Nine-Spot Pattern

Figure 6f and **Table 4** summarize the simulation result for inverted nine-spot pattern. The increase in oil recovery for the inverted nine-spot well pattern reached 3.66% when the injection volume was increased from 1 to 20 HCPV. Compared with the base case, the total recovery improvement was 7.99%, which represents the highest oil recovery increase among the evaluated scenarios.

4.10 Discussion

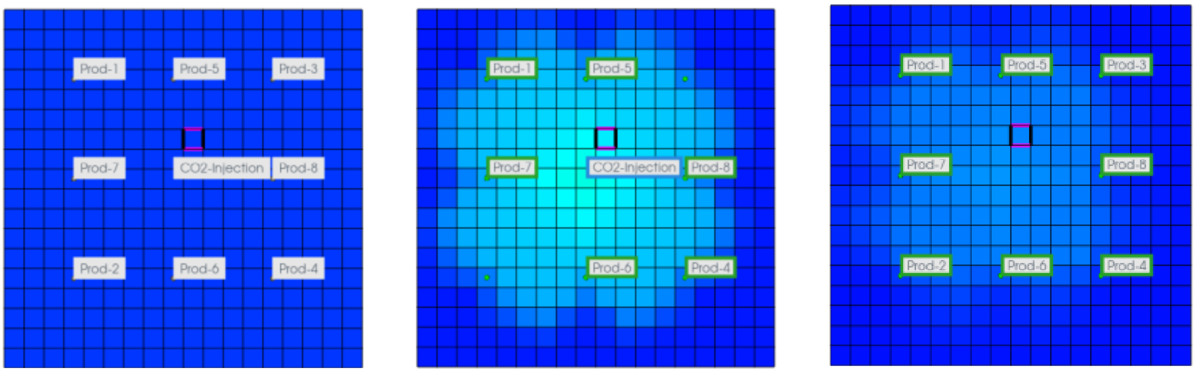
Based on the simulation results that have been conducted, it can be seen that well patterns with an inverted pattern achieve a greater oil increase, and the increase in oil recovery for each injection volume sensitivity is faster compared to non-inverted patterns. This is due to the inverted well pattern having more production wells than injection wells, which creates a larger production area compared to non-inverted well patterns. Furthermore, a larger injection volume also contributes to an increase in oil recovery. Perforation layers also affect oil recovery; perforating below the WOC (Water Oil Contact) zone will lead to decreased oil production and a very high water cut, which results in smaller oil recovery.

After the simulation, the injected CO_2 successfully reached the area around the production wells, indicating that the CO_2 spread to the desired area (**Figure 7**). This helped in increasing oil recovery. After the production period ended, the previously injected CO_2 was still present in the reservoir or can be referred to as CO_2 trapped in the reservoir. This can become a long-term CCS (Carbon Capture Storage) project, where this reservoir can be utilized in the future.

Furthermore, the oil saturation (**Figure 8**) after 25 years of continuous CO_2 injection showed a decrease, particularly in the perforation layer of the production wells. At the beginning of production, the oil saturation in the perforation layer was quite high because oil was still trapped within the rock formation. However, after continuous CO_2 injection, the oil saturation decreased quite significantly as most of the oil was successfully produced. This decrease in oil saturation indicates that continuous CO_2 injection is effective in displacing oil out of the rock pores and pushing it towards the production wells, thereby increasing oil recovery. The following shows the difference in oil saturation at the beginning and end of production.

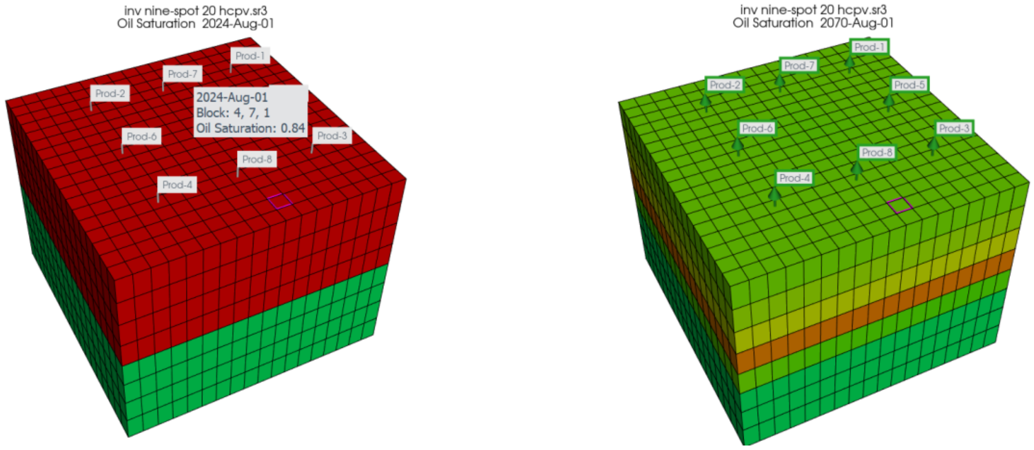
5. Conclusions

Oil recovery using the inverted well pattern showed a greater increase when compared to the non-inverted well patterns (four-spot, five-spot, nine-spot). This result is usually attributed to improved sweep efficiency. Inverted patterns, particularly the inverted 5-spot and 9-spot, often



Initial Production During Shut-in Production End

Fig 7. Global mole fraction of CO2 at different time of simulation



Initial Condition After Production

Fig 8. Oil saturation

create a more favorable pressure gradient, ensuring the injected CO_2 sweeps the area more completely towards the producers before breakthrough occurs.

The simulation results indicate that a larger injection volume yields a greater oil recovery. This demonstrates that the increase in injection volume is proportional to the increase in oil recovery. This finding confirms that the CO_2 EOR process was still effective even at high volumes. The high injection volumes were used to ensure the flood reached its endpoint and to fully exploit the displacement mechanism (likely miscible displacement), overcoming the limitations of short-term economic or time constraints.

Based on the simulation results obtained, the best scenario for increasing oil recovery is the scenario using the inverted nine-spot well pattern with an injection volume of 20 HCPV, yielding an oil recovery of 26.821%. The Inverted Nine-Spot likely outperformed the Inverted Five-Spot because its pattern geometry offers the most uniform areal sweep and a favorable injection-to-production ratio across the modeled area. When combined with the high injection volume, it provided the best conditions for maximizing microscopic displacement and macroscopic sweep efficiency simultaneously.

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