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Carbon Dioxide (CO_2) Injection Planning Using Reservoir Simulation: A Review

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Abstract.

Carbon dioxide (CO_2) injection planning using reservoir simulation has become a significant method in improving oil recovery (EOR) and simultaneously reducing CO_2 emissions to the environment. CO_2 injection divided into two mechanism, immiscible and miscible injection, both of which depend on the injection pressure as well as reservoir characteristics. This study reviews various CO_2 injection mechanisms and their effectiveness through reservoir simulations. In CO_2 injection, a compositional reservoir simulation is used that takes into account the hydrocarbon composition and its equation in pressure, volume, temperature (PVT) analysis. The simulation was used to evaluate the storage capacity, CO_2 migration, and optimize the injection strategy. Results show that CO_2 injection can increase oil recovery, especially in tight reservoirs. Reservoir simulation provides a deeper understanding of reservoir behavior post-CO_2 injection and enables more optimal planning in maximizing hydrocarbon recovery. Overall, this study emphasizes the importance of using reservoir simulation in CO_2 injection planning and optimization. With the right approach, this technology can significantly increase oil recovery while aiding climate change mitigation through underground CO_2 storage.

Keywords: CO_2 injection, immiscible injection**,** miscible injection, reservoir simulation.

Abstrak.

Perencanaan injeksi karbon dioksida (CO_2) menggunakan simulasi reservoir telah menjadi metode penting dalam meningkatkan perolehan minyak (EOR) serta secara bersamaan mengurangi emisi CO_2 ke lingkungan. Injeksi CO_2 dibagi menjadi dua mekanisme, yaitu injeksi immiscible dan miscible, yang keduanya bergantung pada tekanan injeksi serta karakteristik reservoir. Studi ini mengulas berbagai mekanisme injeksi CO_2 dan efektivitasnya melalui simulasi reservoir. Dalam injeksi CO_2, digunakan simulasi reservoir komposisional yang mempertimbangkan komposisi hidrokarbon serta persamaannya dalam analisis tekanan, volume, suhu (PVT). Simulasi ini digunakan untuk mengevaluasi kapasitas penyimpanan, migrasi CO_2, dan mengoptimalkan strategi injeksi. Hasil simulasi menunjukkan bahwa injeksi CO_2 dapat meningkatkan perolehan minyak, terutama pada reservoir ketat. Simulasi reservoir memberikan pemahaman yang lebih mendalam tentang perilaku reservoir setelah injeksi CO_2 dan memungkinkan perencanaan yang lebih optimal dalam memaksimalkan perolehan hidrokarbon. Secara keseluruhan, studi ini menekankan pentingnya penggunaan simulasi reservoir dalam perencanaan dan optimasi injeksi CO_2. Dengan pendekatan yang tepat, teknologi ini dapat secara signifikan meningkatkan perolehan minyak sambil mendukung mitigasi perubahan iklim melalui penyimpanan CO_2 bawah tanah.

Kata kunci: injeksi CO_2, injeksi tak tercampur, injeksi tercampur, simulasi reservoir.

I. INTRODUCTION

Carbon dioxide (CO_2) injection is one of the enhanced oil recovery (EOR) method that leverages CO_2 from undesirable industrial operations, which has a negative influence on the environment (Rosiani et al., 2022). This approach has gained popularity in the petroleum industry due to its dual benefits. Firstly, it reinjects surplus CO_2 into reservoirs, preventing its discharge to the environment. Secondly, it boosts oil recovery to fulfil energy demands (Gozalpour et al., 2005; HU et al., 2019; Kristanto et al., 2025). Currently, many simulations are developed to see the mechanism of CO_2 injection into the reservoir. This is more effective than laboratory experiments that require a lot of material and a long time.

Reservoir simulations are developed based on mathematical equations and techniques contained in reservoir engineering (Hashan et al., 2018). The equations contained in reservoir simulations are very complex and complicated, so computer assistance is needed to solve them. The rapid development of computer technology has made reservoir simulation studies increasingly widely used, because the solution to these equations can be completed in a relatively short time. Reservoir simulation consists of several stages: data preparation, data input, reservoir modelling, initialization, equilibration, history matching, and prediction.

The data that must be prepared includes geological data, reservoir data, pressure data, flow rate data, production data, and other supporting data. This data was obtained from the results of formation evaluation, including: core analysis, drilling logging, well logging, well testing, and correlations. The resulting data is generally still in the form of rough data that is not ready to be used directly as simulator data input, so several initial processing steps are required to produce data that is ready to be used in the reservoir simulation study process (Thapliyal et al., 2018).

CO_2 injection divided into two categories: immiscible flooding injection and miscible flooding injection. The distinction between the two lies in the injection pressure. Both types of injection depend on the reservoir's characteristics. For instance, in miscible flooding, the injection must surpass the minimum miscible pressure (MMP). Achieving MMP requires high pressure, while the reservoir's pressure should not be excessively high, as it would limit the MMP to the formation fracture pressure. When designing CO_2 gas injection, it is crucial to take into account the minimum miscibility pressure (MMP) for injection and the fracture pressure of the targeted zone. Each modification to a component has the potential to either raise or lower the Maximum Mixture Pressure (MMP). However, often, extra light fractions are employed to decrease the MMP by compensating for the gas deficit in the principal gas component that is being injected (Mansour et al., 2021).

For instance, the presence of CO_2 gas can dissolve oil, leading to a reduction in its density and viscosity. Reducing viscosity directly affects the ease with which oil flows to the production well. CO_2 injection offers several benefits. Firstly, CO_2 gas can be sourced from exhaust gas or reservoirs that contain CO_2. Additionally, CO_2 is environmentally benign and does not pose a significant risk of explosion (Seyyedsar et al., 2015).

Compositional Reservoir simulation studies are used to describe reservoir behaviour in the future after CO_2 injection, such as production, pressure, and the age of the reservoir itself, so that reservoir management can run well and maximize hydrocarbon recovery in a field. When planning CO_2 injection through compositional reservoir simulation, it is important to take into account the most effective injection scenario and the duration of the injection (Rotelli et al., 2017).

II. METHODOLOGY

II.1. CO_2 injection and the mechanism

CO_2 injection has been proven to increase oil production by up to twenty percent in tight reservoirs characterized by light oil (Kulkarni & Kulkarni, 1999; Song et al., 2018; Zhou et al., 2018). In addition to this, CO_2 gas injection also supports government programs in reducing gas emissions (Bachu & Adams, 2003). There are two mechanisms of CO_2 gas injection into the reservoir, namely miscible and immiscible gas flooding. CO_2 gas injection dissolves in the oil after interacting either at first contact or after several contacts. This solubility will increase the volumetric sweep and increase the displacement efficiency (EV and ED) so that it will increase oil production to the surface (Claridge, 1972; Mathiassen, 2003). A transitional zone will occur among the reservoir oil and the displacing gas, with the miscibility of the injected gas determined by reservoir pressure, temperature, and oil properties (Jessen et al., 2005; Thomas, 2008). The transition zone containing CO_2 gas injected and dissolved into oil is dispersed in the reservoir, influenced by pressure, temperature, and properties of the oil.

II.2. Miscible flooding

The mechanisms of miscible flooding include light oil component entrapment, viscosity reduction, heavy oil component extraction, and interfacial tension (IFT) reduction (Thomas, 2008). In order for the injected CO_2 gas to be dissolved in the oil, it must be able to exceed the minimum miscible pressure (MMP). The minimum miscible pressure (MMP) of miscible flooding mechanism can be tested using slim-tube method and mathematical correlation (AN & Dessouky, 2018a, 2018b; HU et al., 2019). MMP achieved can be seen from the pressure required to increase oil recovery up to eighty percent at the time of breakthrough (Holm & Josendal, 1974). In the field application that has been done, with an injection volume of 1.2 pore volume, it can increase oil recovery up to 90% (Fu et al., 2024; Taber et al., 1997; Yellig & Metcalfe, 1980).

Dynamic miscibility can occur when medium and heavy oil components are extracted to produce their own gas (gas drive process) and the gas will interact with the oil phase in the reservoir (Merchant, 2010). When there is mass transfer between gas and oil, there is mixing and a transition zone (Jarrell et al., 2002) containing one mixed phase. Oil recovery can be considerably improved through either one or more interactions (Bondor, 1992). Furthermore, the following are the dynamic mechanisms of miscibility that can occur in reservoirs:

a. The high-pressure gas-drive approach uses CO_2 to vaporize intermediate-molecular-weight hydrocarbons in reservoir oil, resulting in dynamic miscibility (Stalkup, 1983).
b. The enhanced gas-drive technique transfers intermediate molecular weight hydrocarbons from a rich solvent to a lean reservoir oil by condensation, resulting in dynamic miscibility (Winkler et al., 1987).

II.3. Immiscible flooding

Immiscible flooding relies on oil viscosity reduction, oil phase expansion, lighter element extraction, and fluid drive (Holm & Josendal, 1982). The difference of miscible and immiscible is CO_2 and oil will not form a single phase (i.e. immiscible), this happens because the MMP pressure is not reached or the oil composition is unfavorable. In miscible flooding gas CO2 dissolves in oil, causing swelling, viscosity reduction, and solution gas generation. This increases sweeping efficiency and contributes to in oil recovery (Martin, 1951). MMP can be increased by increasing the injection pressure, but may decrease with increasing temperature (Leung, 1983; Simon & Graue, 1965).

III. DISCUSSION

III.1. CO_2 injection designs

The CO_2 injection designs depend on reservoir geology, fluid and rock properties of the oil reservoir. There are five design that proven can be applied in the oil field.

a. Continuous gas CO_2 injection

   This method injects CO_2 into the reservoir continuously without any additional fluid or other gas such as nitrogen (N_2). he drawback of this method is that it requires a large volume of CO2 gas, but it can improve the gravity segregation mechanism.

b. Continuous gas CO_2 injection followed with water

   The difference between this method and the first method is the injection of water after the injection of CO_2 gas into the reservoir or CO_2 gas injection in slug form.

   The purpose of this water injection is to increase the efficiency of displacement and sweeping of the extracted oil and decrease its viscosity.

c. Conventional water-alternating-gas (WAG) followed with water
   The difference between this method and the second method is that CO_2 and water are injected alternately. The combination of water and CO_2 injection reduces gas override while increasing CO_2 sweep efficiency.
d. Tapered WAG
   This method is similar to the third method but considers the ratio of CO_2 gas and water injected. Over the injection time there will be a decrease in the injection volume of CO_2 gas compared to the injected water.
e. WAG followed with gas
   This procedure involves a typical WAG operation, followed by a chase of less expensive gas (e.g., air or nitrogen) after injecting the full volume of CO_2.

III.2. Screening Criteria of CO_2 Injection

The selection of a suitable reservoir for CO_2 injection is a key step in project planning. The reservoir characteristics to consider include porosity, permeability, depth, temperature, and pressure. Reservoirs with high porosity and permeability and sufficient depth (usually more than 800 meters) are generally more suitable for CO_2 injection (Bachu, 2000). High reservoir temperature and pressure also help keep CO_2 in the supercritical phase, improving storage efficiency (Chen et al., 2024; Metz et al., 2005).

In addition, the fluid composition of the reservoir is also an important consideration. Reservoirs with high oil or gas content are preferred because they can increase hydrocarbon production through enhanced oil recovery (EOR) or enhanced gas recovery (EGR) processes (Kovscek, 2002). However, formation water reservoirs can also be an option, especially for long-term carbon storage purposes (Benson & Cole, 2008).

Other geological characteristics, such as fault structures and vertical permeability, also need to be evaluated to ensure reservoir integrity and prevent CO_2 leakage (Chadwick et al., 2008). In addition, environmental factors, such as the presence of drinking water sources or human activities near the site, should be considered in the selection of injection sites (Dooley et al., 2006).

Overall, proper reservoir selection based on suitable physical, chemical and geological characteristics is a critical first step in CO_2 injection project planning. Comprehensive analysis and the use of reservoir simulation can help identify the most suitable formation for CO_2 injection by considering various relevant factors. Tabel 1 show the screening criteria for miscible CO_2 flooding.

Table 1. Screening criteria of miscible CO_2-EOR Summary

Reservoir Parameter	Carcoana (1982) (Carcoana, 1982)	Taber& Martin (1983) (Taber & Martin, 1983)	Klins (1984) (Klins, 1984)	Taber et al. (1997) (Taber et al., 1997)	Al Adasani and Bai (Al Adasani & Bai, 2011)	Zhang et. al. (Zhang et al., 2018)
Depth (ft)	< 9843	> 2297	> 2999	> 4,000	15,00 – 13,365	1150-15,600
Temperature (ºC)	< 194	-	-	-	82-257	70-260
Pressure (MPa)	>83	-	-	-		
Porosity (%)		-	-	-	3-37	3 - 37
Permeability (mD)	> 1	-	-	-	1.5 - 4500	0.1 - 9244
Oil gravity (ºAPI)	> 40	> 26	> 30	> 22	22-45	25-48
Viscosity, cp	< 2	< 15	< 12	< 10	>35	0.15-4
Remaining oil (%)	< 30	< 30	< 25	< 20	>15	-
Formation type		Sandstone or carbonate			Sandstone or carbonate	

III.3. CO_2 Injection simulation using reservoir simulator.

Reservoir simulation is a powerful tool that allows engineers and geologists to model the complex behavior of underground reservoirs and predict the performance of various production and injection scenarios (Bui et al., 2018).

Several commercial and open-source reservoir simulation software packages, such as ECLIPSE, CMG, and TOUGH2, have been widely used for CO_2 injection studies. These simulators incorporate advanced models for the thermodynamic and transport properties of CO_2, as well as the interaction between CO_2, the reservoir fluids, and the rock matrix (Doughty & Pruess, 2004).

III.4. Modeling Approaches for CO_2 Injection

The modeling of CO_2 injection in reservoir simulation can be approached in various ways, depending on the specific objectives and the complexity of the problem (Agarwal et al., 2013). Some common modeling approaches include:

1. Static modeling: Characterization of the geological structure and properties of the target formation, including porosity, permeability, and heterogeneity.
2. Dynamic modeling: Simulation of the multiphase flow and transport of CO_2, brine, and other reservoir fluids during the injection and storage process.
3. Coupled modeling: Integration of the reservoir simulation with other models, such as geomechanical, geochemical, or environmental models, to capture the complex interactions between different physical and chemical processes.

The choice of modeling approach depends on factors such as the scale of the problem, the available data, and the specific objectives of the study. In this study, the modelling steps are showed in Figure 1.

III.5. Challenges and Limitations

While reservoir simulation has proven to be a valuable tool for CO_2 injection planning, there are several challenges and limitations that need to be considered (Hosa et al., 2011; Nguyen et al., 2024):

1. Data availability and uncertainty: The accuracy of reservoir simulation depends on the availability and quality of data, such as geological, petrophysical, and fluid property data. Uncertainties in these data can lead to significant uncertainties in the simulation results.
2. Complexity of CO_2 behavior: The behavior of CO_2 in the subsurface can be complex, especially when it interacts with other reservoir fluids and the rock matrix. Accurately modeling these interactions can be challenging and requires advanced models and computational resources.
3. Upscaling and heterogeneity: Reservoir heterogeneity at different scales can have a significant impact on the flow and transport of CO_2. Accurately representing and upscaling these heterogeneities in the simulation model can be a significant challenge.
4. Validation and calibration: Validating and calibrating the simulation models with field data is crucial to ensure the reliability of the results. However, the availability of field data for CO_2 injection projects is often limited, particularly for long-term storage scenarios.

III.6. Future Trends and Opportunities

As the field of CO_2 injection and storage continues to evolve, there are several emerging trends and opportunities that may shape the future of reservoir simulation in this domain (Juanes et al., 2006; Tan et al., 2022):

1. Integrated modeling approaches: The integration of reservoir simulation with other modeling disciplines, such as geomechanics, geochemistry, and environmental impact assessment, is expected to become more prevalent, providing a more holistic understanding of the CO_2 injection and storage process.

2. Uncertainty quantification and risk assessment: Advancements in computational power and numerical algorithms are enabling more robust uncertainty quantification and risk assessment techniques, which are crucial for the successful deployment of CO_2 injection projects.
3. Data-driven and machine learning-based approaches: The increasing availability of field data and the advancements in data-driven and machine learning-based modeling techniques may lead to the development of more efficient and accurate simulation models for CO_2 injection.
4. Coupling with other technologies: The integration of reservoir simulation with emerging technologies, such as real-time monitoring, digital twins, and automated optimization, may further enhance the planning and management of CO_2 injection operations.

In conclusion, reservoir simulation has become an indispensable tool in the planning and optimization of CO_2 injection for carbon capture and storage. As the field continues to evolve, the development of more advanced and integrated modeling approaches, as well as the incorporation of emerging technologies, will be crucial for the successful deployment of large-scale CO_2 injection projects.

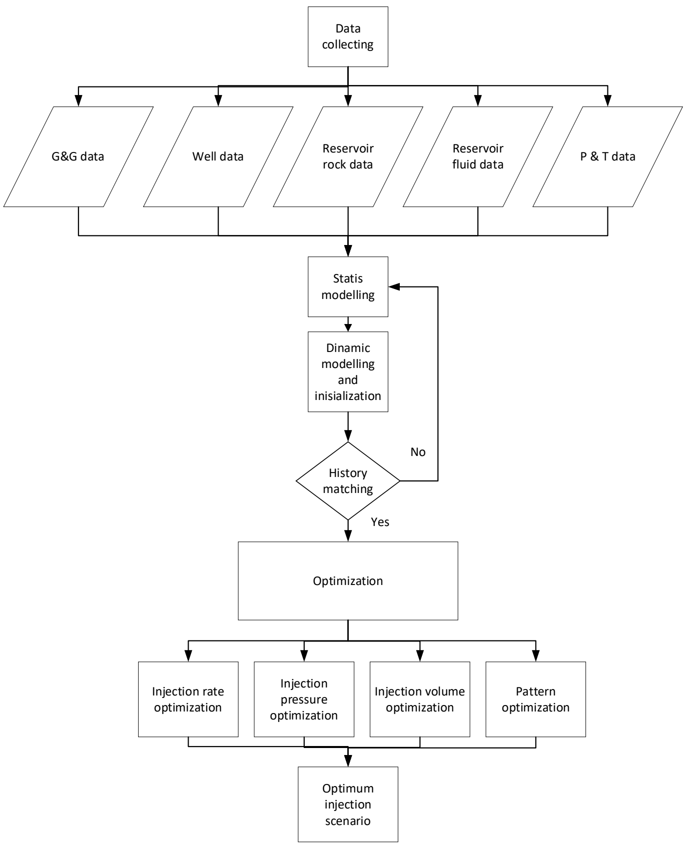

Figure 1. Modelling steps of CO_2 flooding

IV. CONCLUSION

Overall, the reviewed studies conclude that CO_2 injection—both miscible and immiscible—can effectively enhance oil recovery by up to ~20%, particularly in low-permeability, light-oil reservoirs, while also supporting greenhouse-gas mitigation through subsurface CO_2 sequestration. The success of CO_2 injection is strongly governed by reservoir pressure and temperature, and for miscible flooding specifically, reaching the minimum miscibility pressure (MMP) is a key requirement to enable effective CO_2–oil mixing. Because performance depends on many interacting factors, reservoir modeling and simulation are essential to determine optimal injection design (e.g., injection volume, rate/pace, pattern, and operating conditions), thereby reducing the risk of failure and maximizing hydrocarbon recovery. In addition, simulation provides a basis for more accurate forecasting of fluid movement and pressure evolution, enabling better planning and long-term reservoir management after CO_2 injection.

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