Scientific Research Publishing

Open Journal of Yangtze Oil and Gas, 2026, 11(1), 1-33
https://www.scirp.org/journal/ojogas
ISSN Online: 2473-1900
ISSN Print: 2473-1889

Optimizing the Utilization of Carbon Dioxide for Enhanced Oil Recovery in Matured Reservoirs Using the Petroleum Expert Suite

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How to cite this paper: Yinbil, P.J., Atarah, J.J.A. and Miezah, E.B. (2026) Optimizing the Utilization of Carbon Dioxide for Enhanced Oil Recovery in Matured Reservoirs Using the Petroleum Expert Suite. *Open Journal of Yangtze Oil and Gas*, **11**, 1-33.
https://doi.org/10.4236/ojogas.2026.111001

Received: November 28, 2025
Accepted: January 19, 2026
Published: January 22, 2026

Abstract

The growing global demand for energy, coupled with the decline in production from mature oil reservoirs, has necessitated the adoption of advanced recovery strategies that align with both economic and environmental objectives. This study focuses on optimizing the utilization of carbon dioxide (CO_2) for Enhanced Oil Recovery (EOR) in mature reservoirs using the Petroleum Expert Suite (MBAL and PROSPER). A reservoir model was constructed and simulated to evaluate the performance of various CO_2 injection scenarios, with a focus on determining the optimal injection rate and analyzing its impact on oil recovery, pressure maintenance, and sweep efficiency. Sensitivity analyses were performed to assess the impact of varying injection parameters on cumulative oil production and reservoir performance. The results demonstrate that optimized CO_2 injection not only improves recovery factors but also enhances reservoir pressure support and delays gas breakthrough, indicating a more efficient utilization of injected gas. Beyond technical optimization, the study underscores the environmental significance of CO_2-EOR in reducing the carbon footprint and methane emissions associated with oil production. Ultimately, this research illustrates that CO_2-EOR, when optimized through robust simulation tools, represents a viable pathway for extending the productive life of mature reservoirs while supporting global decarbonization goals. The simulation indicates that a significant fraction of injected CO_2 remains sequestered within the reservoir. Under the optimal injection scenario (70 MMscf/day), approximately 35% of CO_2 remains trapped at the end of the simulation period, resulting in a net storage volume of 26827.5 MMscf. This demonstrates that CO_2-EOR simultaneously increases hydrocarbon recovery while contributing to permanent geological sequestration.

Keywords

Carbon Dioxide (CO_2), Enhanced Oil Recovery (EOR), Mature Reservoirs, CO_2 Injection Optimization, Reservoir Simulation, Oil Recovery Factor, Pressure Maintenance, Sweep Efficiency, Decarbonization, Environmental Sustainability

1. Introduction

1.1. General Information

The growing global energy demand and the concurrent decline in production from mature oil fields have driven the need for innovative recovery strategies in the petroleum industry. Among these, Enhanced Oil Recovery (EOR) techniques have gained significant prominence due to their potential to recover additional oil from mature reservoirs, which constitute a large proportion of the world's oil-producing fields [1]. Enhanced Oil Recovery (EOR) technologies, especially those involving carbon dioxide (CO_2), have emerged as dual-purpose methods capable of increasing the number of recoverable hydrocarbons while mitigating greenhouse gas emissions [2]. Mature reservoirs, characterized by declining natural drive energy and reduced production rates, still hold significant volumes of trapped oil. Carbon dioxide (CO_2) injection, a prominent EOR method, has shown considerable promise in improving oil recovery, especially in depleted and mature fields. It enhances oil mobility through viscosity reduction and oil swelling while contributing to reservoir pressure maintenance [1] [3]. More importantly, CO_2-EOR presents a dual benefit: it not only increases hydrocarbon recovery but also facilitates carbon sequestration, thereby contributing to global efforts to mitigate climate change.

Furthermore, in the context of global climate policy and decarbonization efforts, carbon capture, utilization, and storage (CCUS) technologies are becoming a central component of energy transition frameworks. CO_2-EOR not only improves oil recovery but also provides an avenue for permanent geological sequestration of carbon, aligning energy production with environmental sustainability targets [4]. This project explores the optimization of CO_2-EOR operations using Petroleum Expert Suite (PETEX), focusing on maximizing hydrocarbon recovery while reducing the carbon and methane emissions associated with conventional EOR processes.

1.2. Background of Study

The oil and gas industry is currently under immense pressure to balance energy production with environmental stewardship. The combustion of fossil fuels is one of the largest contributors to greenhouse gas (GHG) emissions, particularly carbon dioxide and methane. As the global community moves toward a low-carbon future, carbon management strategies have become essential. Carbon Capture, Utilization, and Storage (CCUS) technologies are integral to this transition. CCUS involves capturing CO_2 emissions from industrial processes and either reusing or storing them underground to prevent their release into the atmosphere. When integrated with EOR, captured CO_2 can be injected into mature oil fields to displace residual oil, achieving two objectives simultaneously: enhanced oil recovery and long-term CO_2 sequestration [5].

Numerous studies have demonstrated the feasibility and effectiveness of CO_2-EOR in increasing recovery factors by 10% to 20% of the original oil in place (OOIP) in mature fields [6]. However, the efficiency of this process is highly dependent on reservoir characteristics, injection strategies, and operational parameters. This necessitates the use of advanced simulation and optimization tools. Field trials and full-scale operations, such as the Weyburn-Midale project in Canada and the SACROC Unit in Texas, have demonstrated the technical feasibility and economic viability of CO_2-EOR. These projects have reported an increase in oil recovery of up to 20% of the original oil in place (OOIP), while simultaneously sequestering millions of tonnes of CO_2 underground [7] [8]. Despite these successes, optimization remains critical, especially in adapting injection strategies to heterogeneous reservoir conditions and minimizing gas breakthrough.

The Petroleum Expert Suite, particularly its components such as MBAL, PROSPER, and GAP, offers a powerful platform for modeling, simulating, and optimizing CO_2-EOR processes. By integrating these tools, engineers can develop accurate forecasts, perform sensitivity analyses, and design economically and environmentally sustainable recovery strategies.

1.3. Purpose and Scope of the Paper

The global drive toward decarbonization necessitates innovative solutions to reduce carbon emissions. Mature oil fields often face declining production rates, and traditional EOR methods can be costly and inefficient.

Carbon Utilization offers a dual benefit of emission reduction and enhanced oil recovery. However, optimizing these processes requires advanced tools capable of accurately modeling complex reservoir dynamics and injection scenarios.

The deployment of CO_2-EOR in mature reservoirs faces multiple challenges. Inefficient injection strategies can result in poor sweep efficiency and early CO_2 breakthrough, undermining both recovery and storage goals. Economic uncertainty, especially with fluctuating oil prices and CO_2 acquisition costs, further complicates decision-making. Additionally, many existing models overlook the environmental dimension, particularly methane emissions that may occur during CO_2-EOR operations.

This study addresses these gaps by applying a robust simulation and sensitivity analysis framework to optimize injection parameters, improve oil recovery, and reduce overall carbon intensity. The use of the Petroleum Expert Suite ensures data-driven decision-making that integrates technical, economic, and environmental performance indicators.

2. Background on Oil Recovery Mechanisms and the Role of CO_2-EOR

After discovery, an oilfield is initially developed and produced through primary recovery methods, utilizing natural reservoir energy, expansion of dissolved gases, rock volume changes, gravity, and aquifer influx to move hydrocarbons to the wellbore. Typically, primary recovery extracts only 5 to 20 percent of the original oil-in-place (OOIP) [3] [9]. These modest recovery rates encourage operators to enhance recovery via secondary methods, which add energy to the reservoir. Secondary recovery involves injecting water or natural gas to repressurize or sustain pressure, and can also serve as a water or gas drive to displace oil. This strategy helps maintain higher production levels and prolongs the reservoir's productive period. Usually, natural gas is injected into the gas cap or at the reservoir's top, while water is injected below the oil-water contact. Overall, the combined recovery from primary and secondary methods ranges from 20 to 40 percent of the OOIP, though it can vary [1] [10]. Despite this, a significant portion of oil remains after secondary recovery, which is targeted with tertiary or enhanced oil recovery (EOR) techniques to produce additional oil [10].

There are three primary techniques of EOR:

1) Gas injection, which uses gases such as natural gas, nitrogen, or carbon dioxide (CO_2), accounts for nearly 60 percent of EOR production in the United States.

2) Thermal injection, which involves the introduction of heat, accounts for 40 percent of EOR production in the United States.

3) Chemical injection, which can involve the use of long-chained molecules called polymers to increase the effectiveness of water floods, accounts for about one percent of EOR production in the United States.

The focus of this Project is Gas (CO_2) injection, or utilization for enhanced oil recovery in depleting reservoirs, as well as the environmental impact of CO_2-EOR on decarbonization [11]. Gas injection or miscible flooding is currently the most commonly used approach in enhanced oil recovery. Miscible flooding is a general term for injection processes that introduce miscible gases into the reservoir [3]. A miscible displacement process maintains reservoir pressure and improves oil displacement because the interfacial tension between oil and water is reduced. This refers to removing the interface between the two interacting fluids. This allows for total displacement efficiency [10]. Gases used include CO_2, natural gas, or nitrogen. The fluid most commonly used for miscible displacement is carbon dioxide because it reduces the oil viscosity and is less expensive compared to the other methods [2] [9]. Oil displacement by carbon dioxide injection relies on the phase behavior of the mixtures of that gas and the crude, which are strongly dependent on reservoir temperature, pressure, and crude oil composition [12].

2.1. Sources of CO_2 and Carbon Capture and Storage (CCS)

There are three (3) possible sources of CO_2:

1) Natural hydrocarbon gas reservoirs containing CO_2 as an impurity (generally less than 25 percent),

2) Industrial or anthropogenic sources with a wide variation of CO_2 percentage in the effluent.

3) Natural CO_2 reservoirs. Depending on the purity, the source gas would require processing in order to bring the CO_2 concentration high enough (90 - 98 percent) for EOR, especially for a miscible process.

2.1.1. Carbon Capture and Storage (CCS)

Carbon capture and storage (CCS) is the process of capturing waste carbon dioxide (CO_2), usually from large point sources, such as a cement factory or biomass power plant, transporting it to a storage site, and depositing it where it will not enter the atmosphere, normally an underground geological formation [4]. The aim is to prevent the release of large quantities of CO_2 into the atmosphere from heavy industry. It is a potential means of mitigating the contribution to global warming and ocean acidification of carbon dioxide emissions from industry and heating [11]. Carbon dioxide can be captured out of air, industrial sources, or power plant flue gas using a variety of technologies, including absorption, adsorption, chemical looping, or membrane gas separation technologies [13]. Amines are the leading carbon scrubbing technology. CCS applied to a modern conventional power plant could reduce CO_2 emissions to the atmosphere by approximately 80% - 90% compared to a plant without CCS [14].

2.1.2. CO_2 Capture by Adsorption

Carbon dioxide adsorbs to a metal organic framework (MOF) through physisorption or chemisorption based on the porosity and selectivity of the MOF, leaving behind a Greenhouse gas-poor gas stream that is more environmentally friendly. The carbon dioxide is then stripped off the MOF using temperature swing adsorption (TSA) or pressure swing adsorption (PSA) so the MOF can be reused.

2.1.3. CO_2 Capture by Chemical Looping Combustion

Chemical looping uses a metal oxide as a solid oxygen carrier. Metal oxide particles react with a solid, liquid, or gaseous fuel in a fluidized bed combustor, producing solid metal particles and a mixture of carbon dioxide and water vapor. The water vapor is condensed, leaving pure carbon dioxide, which can then be sequestered. After capture, the CO_2 would have to be transported to suitable storage sites. This would most likely be done by pipeline, which is generally the cheapest form of transport for large volumes of CO_2.

2.2. Carbon Dioxide (CO_2) Flooding

Carbon dioxide (CO_2) flooding is a process whereby carbon dioxide is injected into an oil reservoir in order to increase output when extracting oil. When a reservoir's pressure is depleted through primary and secondary production, carbon dioxide flooding can be an ideal tertiary recovery method. It is particularly effective in reservoirs deeper than 2500 ft, where CO_2 will be in a supercritical state, with API oil gravity greater than 22˚ - 25˚, and remaining oil saturation greater than 20%. Carbon dioxide flooding is not affected by the lithology of the reservoir area, but simply by the reservoir porosity and permeability, so it is viable in both sandstone and carbonate reservoirs. By injecting CO_2 into the reservoir, the viscosity of any hydrocarbon will be reduced, and hence it will be easier to sweep to the production well. In CO_2 flooding, the first step is the injection of water into the reservoir, which will cause the reservoir pressure to increase. Once the reservoir has sufficient pressure, the next step is to pump the CO_2 down through the same injection wells. The CO_2 gas is forced into the reservoir to come into contact with the oil. This creates a miscible zone that can be moved more easily to the production well. Normally, the CO_2 injection is alternated with water injection, and the water acts to sweep the oil towards the production zone.

2.2.1. Reservoir Selection for CO_2 Flooding

The CO_2 from a natural or industrial source is injected into a selected oil reservoir either as continuous gas or as water-alternating-gas injection, also known as WAG [10]. Not all reservoirs are suitable for CO_2-EOR and are screened based on factors such as reservoir geology, minimum miscibility pressure (MMP), oil gravity, and viscosity to help identify the most likely candidates for miscible CO_2 injection [9]. Most commonly selected reservoirs have a minimum midpoint reservoir depth of 3000 ft., because the temperature and pressure at that depth foster miscibility of CO_2 with the reservoir oil and also help to accommodate high-pressure CO_2 injection [3]. Reservoir selection is a critical determinant of the success of CO_2 flooding as an Enhanced Oil Recovery (EOR) technique. Ideal reservoirs for CO_2-EOR should have favorable geological, petrophysical, and fluid properties that facilitate the efficient displacement of residual oil and maximize CO_2 utilization [12]. Key parameters considered include reservoir depth, pressure, temperature, oil gravity, permeability, porosity, and residual oil saturation.

1) Depth and Pressure

Reservoirs must be deep enough (typically >800 meters) to maintain CO_2 in a supercritical state, enhancing its miscibility with crude oil. A pressure above the Minimum Miscibility Pressure (MMP) is required to achieve miscible flooding, which promotes better oil recovery by reducing interfacial tension [10].

2) Temperature

Moderate reservoir temperatures (generally between 30˚C and 120˚C) are ideal, as higher temperatures can hinder CO_2 miscibility with oil, while too low temperatures may reduce CO_2 mobility [3].

3) Oil API Gravity

CO_2 flooding is most effective in reservoirs with light to medium oils (typically >22˚ API). Heavy oils show poor miscibility and require additional thermal or chemical support [15].

4) Porosity and Permeability

High porosity (≥10%) and permeability (≥10 mD) facilitate better CO_2 injectivity and oil displacement. Heterogeneous formations may lead to CO_2 channeling and early breakthrough, thus affecting recovery efficiency [16]. Screening Criteria for miscible flooding in CO_2-EOR are summarized below (**Table 1**).

Table 1. Screening criteria for application of CO_2 miscible flood [17].

Parameter	Typical Range
Depth	>800 m
Pressure	>Minimum Miscibility Pressure (MMP)
Temperature	30˚C - 120˚C
Oil API Gravity	>22˚
Porosity	≥10%
Permeability	≥10 mD
Residual Oil Saturation	>20%

5) Residual Oil Saturation and Original Oil in Place (OOIP)

Reservoirs with high residual oil saturation after primary and secondary recovery (>20%) and substantial OOIP are attractive candidates for CO_2-EOR, as they provide significant incremental recovery potential.

2.2.2. Fundamentals of CO_2 Flooding Process

The CO_2-EOR process recovers oil that remains in the reservoir after primary and secondary recovery by contacting and mobilizing stranded oil through improving the volumetric sweep (Ev) and displacement Efficiencies (Ed), which are further discussed in the section Oil Recovery Factor or Efficiency. The injected CO_2 may become miscible or remain immiscible with oil, depending on reservoir pressure, temperature, and oil properties [18]. The miscible CO_2-EOR process typically achieves higher recoveries than the immiscible process, and therefore, it is a preferred option.

2.3. CO_2 Injection Mechanism in CO_2-EOR

In mature reservoirs, the natural energy of the reservoir is depleted, making external energy input necessary for continued production. CO_2 injection operates under two mechanisms, that is: 1) Miscible, 2) Immiscible.

2.3.1. Miscible Flooding

The pressure at which miscibility occurs is defined as the minimum miscibility pressure (MMP). MMP is defined as the pressure at which more than 80 percent of oil-in-place (OIP) is recovered at CO_2 breakthrough [3] [10]. Oil recovery increases rapidly with increasing pressure, then flattens out when MMP is reached. When injected, CO_2 mixes completely with oil, eliminating the interface between the fluids. This process typically requires that the reservoir pressure exceed the minimum miscibility pressure (MMP). Miscible CO_2-EOR offers higher recovery efficiency and is ideal for light oil reservoirs [19]. At pressures above the Minimum Miscibility Pressure (MMP), CO_2 becomes miscible with reservoir oil. This miscibility eliminates the interfacial tension between oil and CO_2, allowing the two fluids to mix and displace oil efficiently. Miscible CO_2 flooding is more effective and leads to higher recovery [3].

There are three types of hydrocarbon miscible mechanisms: first contact, vaporizing gas drive, also known as high-pressure gas drive, and the condensing gas drive, sometimes called enriched gas drive [3] [10]. First-contact miscible solvents mix with reservoir oil in all proportions, and the mixture remains in one phase. Other solvents, like CO_2, are not miscible on the first contact, but they do develop miscibility on multiple contacts, known as dynamic miscibility, resulting in much-improved oil recovery. The vaporizing gas-drive process achieves dynamic miscibility by in situ vaporization of the intermediate molecular weight hydrocarbons from the reservoir oil into the injected gas or CO_2.

The condensing gas-drive process achieves dynamic miscibility by in-situ transfer of intermediate molecular-weight hydrocarbons (or CO_2 in the case of CO_2-EOR) into the reservoir oil. When the reservoir pressure is above the MMP, miscibility between CO_2 and reservoir oil is achieved with time, as displacement occurs in what is classified as multiple-contact or dynamic miscibility. The intermediate and higher molecular weight hydrocarbons from the reservoir oil vaporize into the CO_2 (vaporization gas-drive process), and part of the injected CO_2 dissolves into the oil (condensation gas-drive process). This mass transfer between the oil and CO_2 allows the two phases to become completely miscible without any interface and helps to develop a transition zone that is miscible with oil in the front and with CO_2 in the back. Slim-tube tests are normally conducted in a laboratory to determine the MMP and are considered more reliable than the mathematical models or correlations [10] [19]. Because slim-tube tests are expensive, mathematical models and correlations are two additional options available to estimate MMP.

2.3.2. Immiscible Flooding

When the reservoir pressure is below MMP, CO_2 injection leads to immiscible flooding. While less efficient than miscible flooding, it still improves oil mobility by reducing viscosity and swelling oil volume [20]. When the reservoir pressure is below the MMP or the reservoir oil composition is not favorable, the CO_2 and oil will not form a single phase and will not be miscible. However, CO_2 will dissolve in the oil, causing oil swelling and viscosity reduction that both help to improve sweep efficiency and will facilitate additional oil recovery. Like hydrocarbon gases, CO_2 solubility in oil increases with pressure and decreases with temperature at pressures below MMP. CO_2 is only partially soluble in oil. Though not as effective as miscible flooding, immiscible CO_2 injection can still enhance recovery by reducing its viscosity and increasing reservoir pressure [10].

At lower pressures (<200 psia), CO_2 solubility in oil is relatively low. As pressure increases (600 - 800 psia), Solubility increases significantly, enhancing oil swelling and viscosity reduction (Figure 1). Beyond the Minimum Miscibility Pressure (MMP), further pressure increases may not substantially increase solubility, but they support miscibility conditions.

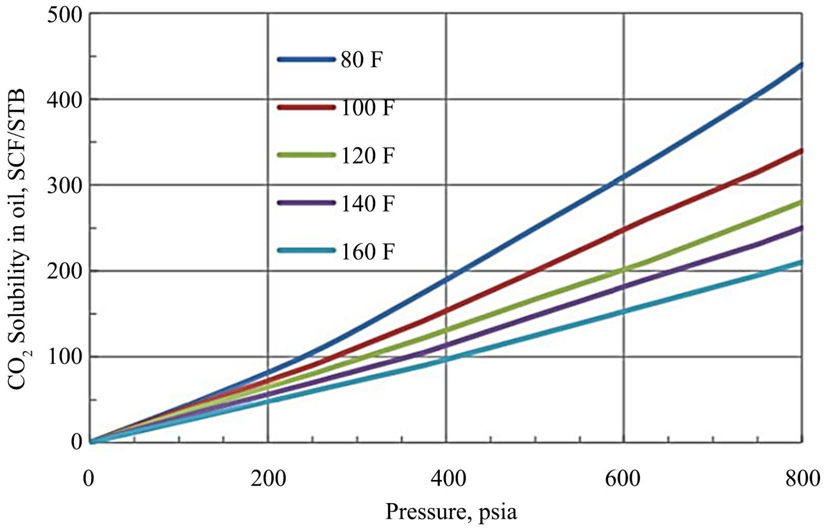

Figure 1. CO_2 Solubility variation with pressure and temperature.

2.3.3. Key Physical Effects of Miscible CO_2 Flooding

Oil Swelling: CO_2 dissolves in crude oil, causing it to swell and expand. This increases oil volume and drives it toward production wells.

Viscosity Reduction: CO_2 significantly reduces the viscosity of oil, improving its mobility within the reservoir [20].

Reduction in Interfacial Tension: In miscible floods, interfacial tension approaches zero, helping mobilize oil droplets trapped in pore spaces.

Reservoir Pressure Maintenance: CO_2 injection helps maintain or increase reservoir pressure, counteracting the depletion effects from earlier recovery phases.

Process Types

Continuous CO_2 Injection: Pure CO_2 is continuously injected until economic oil recovery is achieved.

Water-Alternating-Gas (WAG) Injection: CO_2 and water are injected in alternating slugs to improve sweep efficiency and reduce gas channeling. WAG is the most commonly applied CO_2-EOR technique [19].

Thermodynamic and Phase Behavior: Understanding CO_2-oil phase behavior is critical. At reservoir conditions, CO_2 often exists in a supercritical state (dense like a liquid, mobile like a gas), which enhances its ability to penetrate small pores and mix with oil [21].

2.4. CO_2 Flooding Systems/Injection Designs

After screening the oil reservoirs for CO_2-EOR candidates, the task of developing a design for optimal recovery efficiency of the flooding process follows. Depending on the reservoir geology, fluid, and rock properties, timing relative to water flooding, and well-pattern configuration, the CO_2-EOR flood may use one of several recovery methods as described below:

Continuous CO_2 injection: This process involves the continuous injection of a predetermined volume of CO_2, with no other fluid added. Sometimes a lighter gas, such as nitrogen, follows CO_2 injection to maximize gravity segregation. This approach is implemented after primary recovery and is generally suitable for gravity drainage of reservoirs with medium to light oil, as well as reservoirs that are strongly water-wet or are sensitive to water flooding.

Continuous CO_2 injection followed by water: This process is the same as the continuous CO_2 injection process except for chase water that follows the total injected CO_2 slug volume. This process works well in reservoirs of low permeability or moderately homogeneous reservoirs.

Conventional water-alternating-gas (WAG) followed by water: In this process, a predetermined volume of CO_2 is injected in cycles alternating with equal volumes of water. The water alternating with CO_2 injection helps overcome the gas override and reduces the CO_2 channeling, thereby improving overall CO_2 sweep efficiency. This process is suitable for most of the reservoirs with permeability contrasts among various layers.

Tapered WAG: This design is similar in concept to the conventional WAG but with a gradual reduction in the injected CO_2 volume relative to the water volume. With an objective to improve CO_2 utilization, tapered WAG is the method most widely used today because this design improves the efficiency of the flood and prevents early breakthrough of the CO_2, thus less recycled CO_2 and better oil recoveries. The CO_2 utilization is the volume of CO_2 used to produce a barrel of oil and is reported either as a gross volume, including the recycled CO_2, or a net volume.

WAG followed with gas: This process is a conventional WAG process followed by a chase of less expensive gas (for example, air or nitrogen) after the full CO_2 slug volume has been injected.

2.5. Oil Recovery Factor or Efficiency

Oil recovery efficiency (ER) is a measure of the effectiveness of the enhanced oil recovery process and has two components: volumetric sweep efficiency (EV) and displacement efficiency (ED) [22].

Volumetric sweep efficiency (EV) is a measure of the volume of a reservoir contacted by the injected fluid and depends on the injection pattern selected, fractures in the reservoir, position of gas-oil and oil-water contacts, reservoir thickness, permeability, and areal and vertical heterogeneity, mobility ratio, density difference between the displacing and the displaced fluid, and flow rate. The displacement efficiency (ED) relates to the displacement or mobilization of oil at the pore level and is defined as the fraction of oil that has been recovered from a zone swept by a waterflood or other displacement process.

Displacement efficiency is a function of reservoir pressure and temperature, oil composition, fluid behavior and properties, saturation history of rock-fluid system, slug size, mobility ratio, rock wettability, rock-pore geometry, and structure [22] [23]. Displacement efficiency is equal to $(1 - S_{wi} - S_{or})/(1 - S_{wi})$, where S_{Wi} is the initial or connate water saturation and Sor is the residual oil saturation.

Typical Values [3] [10]:

- ED = 90% - 100% in miscible CO_2 floods
- ED = 30% - 70% in immiscible CO_2 floods

Volumetric efficiency (EV) is a product of both areal efficiency (EA) and vertical efficiency (EI), as shown by the following equation. EV = EA × EI.

The areal sweep efficiency (EA) is defined as the fraction of the pattern area from which reservoir fluid is displaced by the injected phase at the time of breakthrough, and it is affected by parameters such as formation dip angle and dip azimuth, presence of fractures, mobility ratio, injection pattern, and directional permeability. The vertical displacement efficiency (EI) is defined as the ratio of the cumulative height of the vertical sections of the pay zone that are contacted by injection fluid to the total vertical pay-zone height, and it depends on parameters such as mobility ratio, total volume of fluid injected, and the permeability contrast between different pay zones [3].

2.6. Feasibility and Simulation Planning for CO_2-EOR

Before implementing a CO_2-EOR project, it is essential to assess its feasibility through a combination of laboratory investigations, empirical correlations, and reservoir screening criteria. One of the primary considerations is the miscibility of CO_2 with the reservoir oil. This is typically evaluated using empirical correlations [20] [23] or, when high accuracy is required, laboratory experiments such as slim-tube tests to determine the Minimum Miscibility Pressure (MMP) and the oil-CO_2 interfacial behavior. Establishing miscibility ensures high displacement efficiency and lower interfacial tension between CO_2 and oil, leading to improved microscopic sweep [3].

Once the reservoir meets favorable miscibility and geologic conditions (e.g., adequate permeability, thickness, and mobility ratio), a pilot CO_2-EOR test is typically conducted. This pilot test helps assess the behavior of the CO_2 slug on a small scale under actual field conditions and provides insight into breakthrough times, injectivity, and recovery potential. If the pilot test results validate simulation forecasts and confirm economic viability, the CO_2-EOR process is scaled up to a full-field deployment [10]. A key aspect of scaling up includes determining the hydrocarbon pore volume (HCPV) to be injected, typically expressed as a fraction of the total reservoir pore volume that contains movable hydrocarbons. The HCPV serves as a baseline for designing injection slug volumes and optimizing water-alternating-gas (WAG) cycles, which improve macroscopic sweep by reducing gas channeling and improving areal and vertical coverage [19].

2.6.1. Reservoir Simulation in CO_2-EOR Planning

Reservoir simulation plays a critical role in the design and planning phase of CO_2-EOR projects. It allows engineers to test various injection strategies, quantify potential recovery, and optimize the field development plan. The simulation process typically involves three major phases:

1) Data Input and Initialization

This phase involves inputting all reservoir and fluid parameters, ensuring an accurate representation of physical and chemical conditions. Essential inputs include reservoir geometry, porosity, permeability, fluid PVT data, relative permeability curves, and well configuration. Initialization also defines initial saturations and pressure conditions [3].

2) History Matching

The simulator's output is compared with actual historical field data, including oil, gas, and water production as well as reservoir pressure. Sensitive parameters such as aquifer strength, relative permeability endpoints, and transmissibility are tuned to improve the match between modeled and observed performance. A good history match validates the model and builds confidence in subsequent forecasts [24].

3) Forecasting

In the forecasting phase, multiple simulation scenarios are run using varying WAG ratios, injection rates, and total HCPV volumes to determine the optimum configuration. This allows for the evaluation of different development strategies and estimation of potential recovery enhancement. Key forecast outputs include cumulative oil production, CO_2 utilization factor, and gas breakthrough times [19].

2.6.2. Monitoring and Optimization during CO_2-EOR

Post-implementation, the performance of the CO_2-EOR process is continuously monitored. The monitoring program focuses on:

1) CO_2 slug integrity and the alternating water slugs;

2) Oil production rate and GOR;

3) Water cut trends;

4) Fluid distribution among reservoir layers and zones.

These parameters are monitored using production logs, pressure gauges, tracer studies, and periodic PVT sampling. The performance of injection and production wells is analyzed, and if necessary, remedial actions such as zonal isolation, mobility control (e.g., foam), or re-perforation are undertaken to improve sweep efficiency and oil recovery [21] [25].

Among all design parameters, the CO_2 and water injection volumes and their alternation ratio (WAG ratio) are the most influential in determining the overall Recovery Factor (RF). A well-optimized injection strategy enhances both the displacement efficiency (ED) by achieving miscibility and volumetric sweep efficiency (EV) by minimizing bypassed zones.

2.7. Infrastructure Needs for CO_2 EOR

CO_2 EOR projects require infrastructure to handle the injection, production, separation, and recycling of CO_2 in a closed-loop system. This infrastructure includes equipment within the oil field and outside the field. Infrastructure outside the field is commonly shared among several CO_2 EOR projects, creating economies of scale.

Within the Field

The addition of new facilities and equipment within the field is needed when developing CO_2 EOR projects. This infrastructure is used to receive CO_2 that is delivered to the field and to distribute it to the injection wells located throughout the field. On the production side, well testing and fluids separation equipment, often located at centralized processing facilities called central tank batteries, must be modified to accept the gaseous CO_2 that is produced, then to recompress the CO_2 so that it may be reinjected in the closed-loop process.

The key specific equipment needed for CO_2 EOR is:

1) Injection manifolds capable of accommodating a WAG process.

2) Injection well instrumentation and metering capable of measuring the two separate fluids associated with WAG injection water and dense phase CO_2, each with different volumetric properties.

3) Producing well instrumentation and metering to measure the amount of gas, oil, and water of each producer well.

4) Produced-fluid handling systems, including a remote well testing facility (satellite) and a central tank battery designed to separate oil, water, and gas streams and that can accommodate high concentrations of CO_2. Before entering the high-pressure, three-phase separator, the EOR fluid production mixture is typically treated with demulsifiers, scale inhibitors, and corrosion inhibitors to aid the fluid's separation process and protect the process equipment.

5) Reinjection Compression Plant (RCP) for produced gas from the high-pressure three-phase separator (that contains CO_2 and hydrocarbon gas) to compress the mixture for transmission to a gas recovery plant where CO_2 will be separated from hydrocarbon gases for recycling. The CO_2 content in the gas stream impacts compressor operation and requires careful monitoring and adjustments. Sensors may be located upstream of this compressor to quantify the amount of CO_2 being produced.

6) CO_2 recovery plant capable of separating a pure CO_2 stream from the produced gas for recompression and reinjection, and the collection of natural gas liquids for sale. There are several CO_2 separation options available (chemical solvents, physical solvents, membranes, cryogenic processes, etc.), depending on the nature of the produced gas, the throughput rate, and other factors. Each has advantages and disadvantages, and sometimes a combination of these is required. An alternative to building a CO_2 recovery plant is to reinject the produced gas stream using the RCP, which is only viable if the gas composition does not adversely affect the MMP.

High-volume artificial lift systems capable of handling high volumes of liquid before gas breakthrough in the reservoir and CO_2 in the produced gas after breakthrough. One option is to use compressed, recycled CO_2 as a gas lift fluid.

3. Methodology

3.1. Introduction

This section outlines the methodological approach adopted to achieve the two main objectives of this study:

1) Modeling and simulating various CO_2 injection scenarios to assess their impact on hydrocarbon recovery.

2) Performing sensitivity analysis to determine the optimal injection parameters, and this approach allows a comprehensive assessment of the microscopic and macroscopic efficiency improvements due to CO_2-EOR while estimating potential oil recovery in terms of volumetric sweep and displacement efficiencies. The simulation workflow involves the use of MBAL (Material Balance Software) for dynamic reservoir behavior prediction and PROSPER for wellbore modeling and injection optimization.

3.2. Materials

3.2.1. The Simulation Tool (PETEX Suite—MBAL & PROSPER)

MBAL is a dynamic reservoir simulation tool developed by Petroleum Experts as part of the Integrated Production Modelling (IPM) suite. It is primarily used for material balance analysis and production forecasting under various reservoir drive mechanisms, including depletion, water drive, gas cap expansion, and enhanced oil recovery (EOR) scenarios such as CO_2 injection.

MBAL enables reservoir models using actual field data for history matching and forecasting. In CO_2-EOR studies, it simulates various injection schemes (e.g., continuous CO_2, WAG) and evaluates impacts on oil recovery, gas breakthrough, and reservoir pressure.

3.2.2 PROSPER (Production System Performance Evaluation Tool)

PROSPER is a well performance modeling tool, also developed by Petroleum Experts, used to design and optimize the behavior of individual wells under production or injection operations. It simulates well inflow and outflow performance by integrating reservoir, tubing, and surface conditions, enabling engineers to assess well deliverability and injectivity under various operating scenarios.

In the context of CO_2-EOR, PROSPER is utilized to:

1) Simulate CO_2 injection wells, considering the fluid properties (e.g., CO_2 viscosity and density), and injection conditions.

2) Perform sensitivity analysis on injection rates, bottomhole pressure (BHP), and tubing size to optimize injectivity and prevent formation damage.

The simulation workflow includes:

1) Reservoir Characterization using available geological and PVT data.

2) Material Balance Modeling (MBAL) to estimate remaining oil and potential recovery under CO_2 flooding.

3) CO_2 Injection Modeling in PROSPER to evaluate injection feasibility and optimize operational parameters.

4) Integration of results to compute overall recovery efficiency ($RF = ED \times EV$).

3.2.3. Data Requirement for Simulation

The MBAL simulator requires comprehensive data to create a dynamic model of the reservoir under study.

1) Reservoir Data (Logs or Core).

2) Average Reservoir pressure measurements.

3) Production History, including all Fluids (Injection if available).

4) Representative PVT Data.

5) Rock and water compressibility.

3.2.4. Model Approach

This model will be used to perform the classical history matching to determine the fluid originally in place. Prediction can also be made using relative permeabilities and well performance (IPR, VLP) to evaluate future reservoir performance based on different production strategies. In this model, a tank represents the total hydrocarbon pore volume of the reservoir; hence, all hydrocarbons in the reservoir are fit into the tank (Zero-dimensional representation).

STEP 1—Reservoir Type Definition: The MBAL tool allows the definition of the reservoir type in terms of fluid content. That is, the reservoir can be defined as oil, gas, or retrograde condensate. In the first step, the fluid type for each reservoir will be defined by the integration of available engineering and petrophysical data.

STEP 2—PVT Parameters Input: This step will involve the entry of basic PVT parameters. Validation of the PVT parameters is key, as these data sets must be valid for the process to run and to suggest the suitability of the data for the evaluation. This stage will be followed by the entry of PVT laboratory data.

STEP 3—Entry of Reservoir Data: Next, enter reservoir data such as temperature, initial pressure, porosity, and connate water saturation. Rock compressibility values for the simulation can be generated from correlations within the model.

STEP 4—Pressure and Production Data: Validity checks will be made on the average reservoir pressure data by plotting these on an Excel spreadsheet. Invalid pressure points will be excluded.

STEP 5—History Matching: This is a process of modifying the input data in a reservoir model until a reasonable comparison is obtained between the observed data and the simulated data. This step is necessary before any prediction of reservoir performance. History matching is carried out using two methods:

1) Analytical History method (non-linear regression)

2) Graphical History method.

STEP 6—Run Simulation Results: After obtaining a history match, the validity of the match will be established by simulating with the final material balance model. The results obtained from the simulations should be compared with the historical input data for pressure, cumulative oil, and injection.

Limitations of the Tank Model

The tank model provides a quick and effective means of estimating the hydrocarbon volumes and predicting overall reservoir performance. However, its zero-dimensional representation presents key limitations. The model assumes uniform or homogenous reservoir properties and pressure distribution, meaning it cannot capture spatial variations such as heterogeneity, permeability layering, fractures, or gravity effects. The model also cannot simulate areal and vertical sweep efficiency, fluid channeling, or conformance issues that commonly affect CO_2-EOR performance in mature reservoirs. As a result, while useful for screening and preliminary forecasting, the tank model simplifies the complex flow dynamics that occur in an actual reservoir.

3.3. CO_2 Injection Modeling in PROSPER

The fluid properties and reservoir parameters used for the simulation are summarized in Table 2. The data (Table 2) provides critical input for the PROSPEPR simulation in evaluating CO_2-EOR feasibility. Static reservoir pressure and reservoir temperature directly influence CO_2 solubility and phase behavior, which are essential in determining miscibility conditions.

Table 2. Fluid (PVT) properties [26].

IPR Model	Parameters
Static Reservoir Pressure	2000 psig
Reservoir Temperature	200˚F
Water Gas Ratio	0 stb/MMscf
Condensate Gas Ratio	0 stb/MMscf
Compaction Permeability Reduction Model	No
Reservoir permeability	150 mD
Reservoir thickness (true stratigraphic thickness)	100 ft
Drainage Area	340 acres
Dietz shape factor	31.6
Wellbore radius (Drill bit radius)	0.354 ft
Perforation interval	100 ft
Time since Production started	10
Reservoir porosity	25%
Connate water saturation	20%
Non-Darcy flow factor (D)	Calculated
Permeability entered	Total permeability
Mechanical skin	+5
Minimum miscibility pressure (MMP)	2100 psia

STEP 1—SYSTEM OPTIONS: Open the prosper file and select "options" to display the system summary and enter the fluid type and well type (Injector).

STEP 2—PVT DATA INPUT: The "PVT input data" section is selected to input the basic PVT data set. **Table 3** provides a summary of the injection fluid PVT parameters.

Table 3. Injection fluid PVT data [26].

Parameter	Value
Gas gravity	0.6 (Air = 1)
Separator pressure	250 psig
Condensate to Gas ratio	0 stb/MMscf
Condensate gravity	50 API
Water to Gas ratio	0 stb/MMscf
Water salinity	10,000 ppm

STEP 3—SYSTEM EQUIPMENT DESCRIPTION: This stage involves the selection and description of the various components in or around the wellbore. This includes the surface equipment, downhole equipment, geothermal gradient, deviation survey, and average heat capacities.

Now, by selecting "Edit", the software will take the user through all the screens necessary to input the equipment data, starting with the deviation survey. The data input for the deviation survey is provided in **Table 4**.

Table 4. Deviation survey data input [27].

Measured Depth in ft	True vertical Depth in ft
0	0
8000	8000

Deviation Survey

Downhole Equipment

The downhole equipment includes the tubings, casings, nipples, sub-surface safety valves, etc.

As indicated in **Table 5**, the deepest entry in the downhole equipment section is the datum depth for the static reservoir pressure that will be entered in the IPR section. It is recommended, as per the model, to take the top perforation as the reference depth for the static reservoir pressure. This would mean that the downhole equipment description shall stop at the top of the perforation. This is also true for multiple-zone completion because the pressure drop between the zones will be considered by the appropriate inflow model (multi-layer IPR model with dP or multilateral IPR model). Selecting is done after the data entry proceeds to the next screen: the geothermal gradient.

Table 5. Downhole equipment data input [27].

Equipment type	Measured Depth in (down to)	Internal diameter, inches	Roughness, inches	Rate Multiplier
N/A	N/A	N/A	N/A	N/A
Tubing	7800	3.992	0.0018	1
Casing	8000	8.3	0.0018	1

Geothermal Gradient

The available geothermal gradient data are provided below (Table 6).

Table 6. Geothermal gradient data input [27].

Measured depth in ft	Static temperature in ˚F
0	70
8000	200

The overall heat transfer coefficient is 3 btu/h/ft2/˚F.

STEP 4—Inflow Performance Relation (IPR) (Table 7): For the selection of the IPR model, simply select “System”, “Inflow performance”, and make the appropriate choices as follows:

Table 7. Data input for IPR curve plot.

Reservoir Permeability	150 md
Reservoir Thickness	100 feet
Drainage Area	340 acres
Dietz Shape Factor	31.6
Wellbore Radius	0.354 feet
Perforation Interval	100 feet
Time since Production Started	10 days
Reservoir Porosity	0.25 fraction
Connate Water Saturation	0.2 fraction

Generating an IPR Plot:

Once the IPR data input is completed, it is a good practice to create an IPR plot to verify that everything makes sense. For this, simply selecting “Calculate” enables the software to create and display the plot.

Also, the concept of AOF does not apply to an injection well. The values displayed correspond to the highest rate for which the IPR pressure was computed.

Estimation of the Well Injection Flow Rate

The response of a well bore combines fluid properties (PVT), reservoir data (IPR), and tubing response (VLP). The fluid properties are used to compute the reservoir response (IPR) and the tubing response (VLP). For a given set of boundary conditions (given reservoir pressure and well head flowing pressure), the well flow rate is the intersection between the IPR curve and the VLP curve. This is calculated in this PROSPER model by selecting "Calculation|System" in the model.

The top node pressure is the pressure downstream of the system. Since there is no pipeline in this PROSPER model, the top node pressure is the wellhead flowing pressure. One can then proceed to calculate and afterward select "Plot" to visualize the system plot.

3.4. Lift Curve Generation for Gas Injectors

Lift curves express the pressure drop across a tubing for a given set of variables. Different software providers use different formats and acronyms for lift curves. In this model, the lift curves that will be considered include;

VLP—Vertical Lift Performance;
IPR—Inflow performance relation;
VFP—Vertical Flow Performance.

To generate wells using vertical lift performance (VLP), the relevant variables, including liquid gas rates and wellhead flowing pressure (WHFP), must be identified [28]. Subsequently, values for these variables should be selected to enable the host application, such as MBAL, to interpolate effectively and determine the required solution. Extrapolation and large variable spacing should be avoided.

4. Results Interpretation and Performance Assessment

4.1. Introduction

The simulation results in this chapter are derived from a constructed model of a mature oil reservoir undergoing CO_2-enhanced oil recovery (CO_2-EOR). The model incorporates a vertical injection well and a deviated production well positioned to maximize sweep efficiency and contact between injected CO_2 and the remaining oil in place.

In this configuration, the vertical injection well delivers CO_2 downward through the reservoir layers, while the deviated production well provides efficient horizontal drainage of mobilized fluids. This arrangement reflects typical field practices where optimized well trajectories improve displacement efficiency, especially in heterogeneous or layered formations.

The simulation was performed using the Petroleum Expert Suite, integrating MBAL for material-balance behavior and PROSPER for injection profiling. The reservoir grid captures both areal and vertical heterogeneity, allowing realistic evaluation of CO_2 movement, pressure evolution, oil recovery, and overall reservoir performance under CO_2-EOR conditions.

4.2. Model of the Reservoir

Table 8 illustrates the historical production data of the reservoir. The trend demonstrates a consistent decline in reservoir pressure accompanied by an increase in cumulative oil and gas production. This trend reflects ongoing reservoir depletion and fluid withdrawal, with gas-oil ratio (Cumulative GOR) also exhibiting a rising pattern.

Table 8. Results of the simulated reservoir model.

Time (date d-m-y)	Reservoir Pressure (psig)	Cum Oil Produced (MMstb)	Cum Gas Produced (MMscf)	Cum Wat. Produced (MMstb)	Cum Gas Injected (MMscf)	Cum Wat. Injected (MMstb)	Cum GOR	Regression Weighting (scf/STB)
01-01-2017	10535.00	0.000	0.000	0.000			0.00	Medium
01-02-2017	10527.00	0.076	0.047	0.002			0.61	Medium
01-03-2017	10519.00	0.152	0.123	0.002			0.81	Medium
01-04-2017	10502.00	0.211	0.189	0.002			0.89	Medium
01-05-2017	10293.00	0.363	0.360	0.002			0.99	Medium
01-06-2017	10076.00	0.545	0.587	0.002			1.08	Medium
01-07-2017	9806.00	0.719	0.899	0.002			1.25	Medium
01-08-2017	9784.00	0.902	1.045	0.002			1.16	Medium
01-09-2017	9356.00	1.454	1.803	0.002			1.24	Medium
01-10-2017	9142.00	1.639	2.096	0.002			1.28	Medium
01-11-2017	9035.00	1.951	2.590	0.002			1.33	Medium
01-12-2017	9003.00	2.097	2.823	0.002			1.35	Medium
01-01-2018	9013.00	2.227	3.024	0.002			1.36	Medium
01-02-2018	9023.00	2.227	3.153	0.002			1.42	Medium
01-03-2018	8912.00	2.307	3.388	0.002			1.47	Medium
01-04-2018	8800.00	2.458	3.641	0.002			1.48	Medium
01-05-2018	8689.00	2.612	3.910	0.002			1.50	Medium
01-06-2018	8697.00	2.775	4.176	0.002			1.50	Medium
01-07-2018	8604.00	2.941	4.264	0.002			1.45	Medium
01-08-2018	8607.00	3.103	4.354	0.002			1.40	Medium
01-09-2018	8705.00	3.269	4.600	0.002			1.41	Medium
01-10-2018	8637.00	3.384	4.291	0.002			1.27	Medium
01-11-2018	8797.00	3.385	4.548	0.002			1.34	Medium
01-12-2018	8712.00	3.389	4.355	0.002			1.28	Medium
01-01-2019	8709.00	3.396	4.456	0.002			1.31	Medium
01-02-2019	8597.00	3.472	4.612	0.002			1.33	Medium
01-03-2019	8488.00	3.582	4.799	0.003			1.34	Medium

Continued

01-04-2019	8380.00	3.660	4.907	0.003	1.34	Medium
01-05-2019	8001.00	3.731	5.147	0.003	1.38	Medium
01-06-2019	7915.00	3.810	5.296	0.005	1.39	Medium
01-07-2019	7510.00	3.954	5.376	0.006	1.36	Medium
01-08-2019	7327.00	4.234	5.478	0.008	1.29	Medium
01-09-2019	7100.00	4.310	5.709	0.008	1.32	Medium
01-10-2019	6900.00	4.489	5.988	0.008	1.33	Medium
01-11-2019	6497.00	4.521	6.145	0.009	1.36	Medium
01-12-2019	6000.00	4.719	6.478	0.012	1.37	Medium
01-01-2020	5670.00	4.800	6.658	0.024	1.39	Medium
01-02-2020	5102.00	4.814	6.808	0.036	1.41	Medium
01-03-2020	4643.00	4.680	6.366	0.009	1.36	Medium
01-04-2020	4300.00	4.968	6.966	0.039	1.40	Medium

4.2.1. Analysis

Figure 2 presents the historical production performance of the mature reservoir, showing the relationship between cumulative oil production (MMSTB) and reservoir pressure (psig) from January 2017 to July 2020. The blue curve illustrates a consistent decline in reservoir pressure from an initial value of approximately 10,800 psig to below 5000 psig by mid-2020, indicating significant depletion.

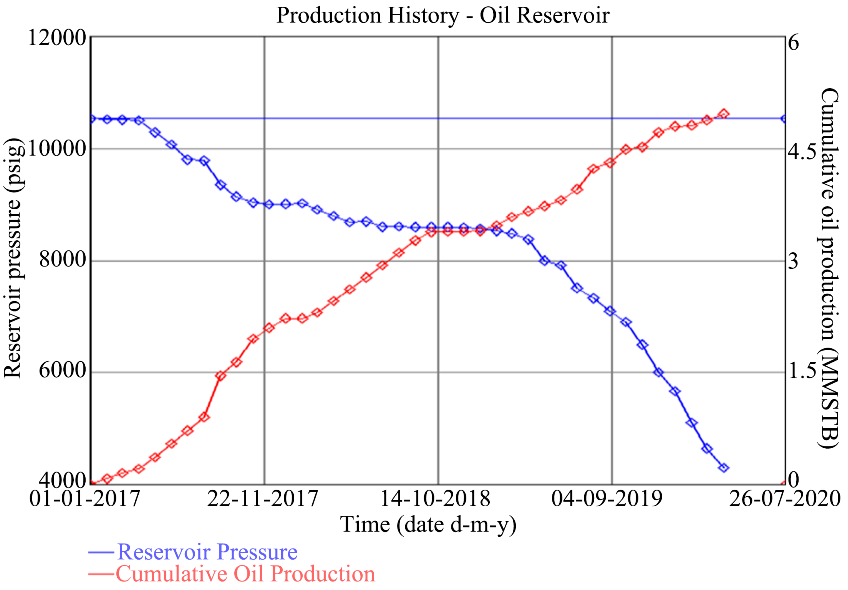

Figure 2. Reservoir pressure against cumulative oil production over time.

Concurrently, the red curve depicts a continuous rise in cumulative oil production, reaching approximately 4.7 MMSTB by the end of the period.

The inverse relationship between pressure and production confirms that the reservoir was predominantly operating under natural depletion. The temporary stabilization of pressure around mid-2018 may suggest either transient aquifer support or early-stage workover operations. However, the sharp decline in pressure beyond 2019 emphasizes the diminishing drive energy within the reservoir, reinforcing its classification as a mature asset.

This production history justifies the application of enhanced oil recovery techniques. With declining pressure and still-increasing cumulative oil production, the opportunity exists to inject CO_2 to restore pressure, improve oil displacement efficiency, and enhance the overall recovery factor. This plot forms the baseline for comparing post-injection performance in subsequent sections.

4.2.2. History Matching

A history matching was conducted to validate the dynamic reservoir model before forecasting. **Figure 3** below illustrates the comparison between the observed historical reservoir pressures and the simulated pressures generated by the calibrated model. The history match plot demonstrates a close alignment between measured pressure-decline trends and the model prediction when aquifer influx is included in the simulation. The "with Aquifer Influx" case (blue curve) successfully represents the characteristic pressure decline from 10,535 psia at the start of production to about 4300 psia after 3.5 MMSTB of cumulative oil production, consistent with the historical dataset. In contrast, the "without aquifer influx" case (red curve) significantly under-predicts reservoir pressure, confirming that edge-water support is an essential component of the reservoir's depletion behaviour. The validated model parameters include a radial Hurst-Van Everdingen-Drake aquifer with an estimated aquifer volume of 13582.4 $MMft^3$.

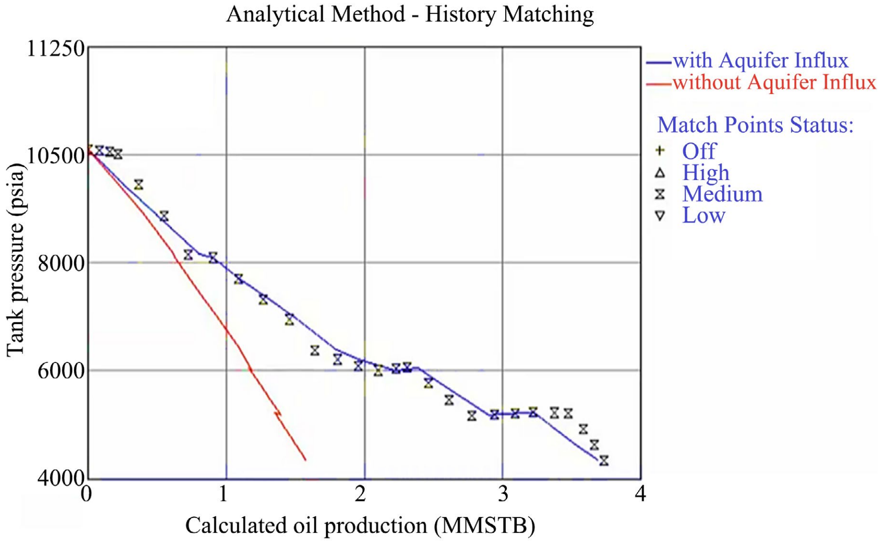

Figure 3. History match of observed historical data against simulated model output.

The close alignment between observed and simulated pressures indicates that the model accurately captures the reservoir drive mechanisms, fluid properties, and production response. This validation strengthens reliability on the subsequent CO_2-EOR optimization forecast.

4.3. CO_2 Injection Design and Simulation Results

In this study, CO_2 Enhanced Oil Recovery (EOR) is simulated using PROSPER, focusing strictly on subsurface behavior from reservoir inflow to the wellhead. The simulation excludes surface facilities, isolating the analysis to the wellbore and reservoir interaction.

4.3.1. IPR and VLP Integration

PROSPER calculates the intersection of the Inflow Performance Relationship (IPR), representing reservoir deliverability, and Vertical Lift Performance (VLP), capturing wellbore pressure losses, without the complexity of surface pipeline network modelling. PROSPER uses PVT properties applicable to CO_2 or oil systems and selected multiphase correlations to compute the VLP results, such as injection rates at specified pressures, which are derived directly from these subsurface interactions. The inflow performance relationship calculation results for the CO_2 injection well design are summarized below (**Table 9**).

Table 9. Inflow calculation results.

Gas Injection Rate (MMscf/day)	Reservoir Pressure (psig)	dP Total (psi)	Skin Total	dP Perforation (psi)	dP Damage (psi)	dP Completion (psi)	Completion Skin	Sand Control Skin
0.299	2000.59	0	0	0	0	0	0	0
157.636	2562.23	0	0	0	0	0	0	0
314.973	3502.94	0	0	0	0	0	0	0
472.31	4746.72	0	0	0	0	0	0	0
629.647	6307.26	0	0	0	0	0	0	0
786.984	8228.34	0	0	0	0	0	0	0
944.321	10557.77	0	0	0	0	0	0	0
1101.658	13289.36	0	0	0	0	0	0	0
1258.995	16410.41	0	0	0	0	0	0	0
1416.332	19920.94	0	0	0	0	0	0	0
1573.669	23820.93	0	0	0	0	0	0	0
1731.006	28110.4	0	0	0	0	0	0	0
1888.343	32789.34	0	0	0	0	0	0	0
2045.68	37857.74	0	0	0	0	0	0	0
2203.017	43315.62	0	0	0	0	0	0	0
2360.354	49162.96	0	0	0	0	0	0	0
2517.691	55399.77	0	0	0	0	0	0	0
2675.028	62026.05	0	0	0	0	0	0	0
2832.365	69041.8	0	0	0	0	0	0	0
2989.702	76447.02	0	0	0	0	0	0	0

Figure 4 below illustrates a sketch of the subsurface of the injection well. Upon entering the data for the various subsurface parameters into the reservoir model (data for deviation survey, downhole equipment, geothermal gradient, and average heat capacities), it simulates the subsurface, indicating optimum tubing and casing sizing as well as the depth or trajectory of placement.

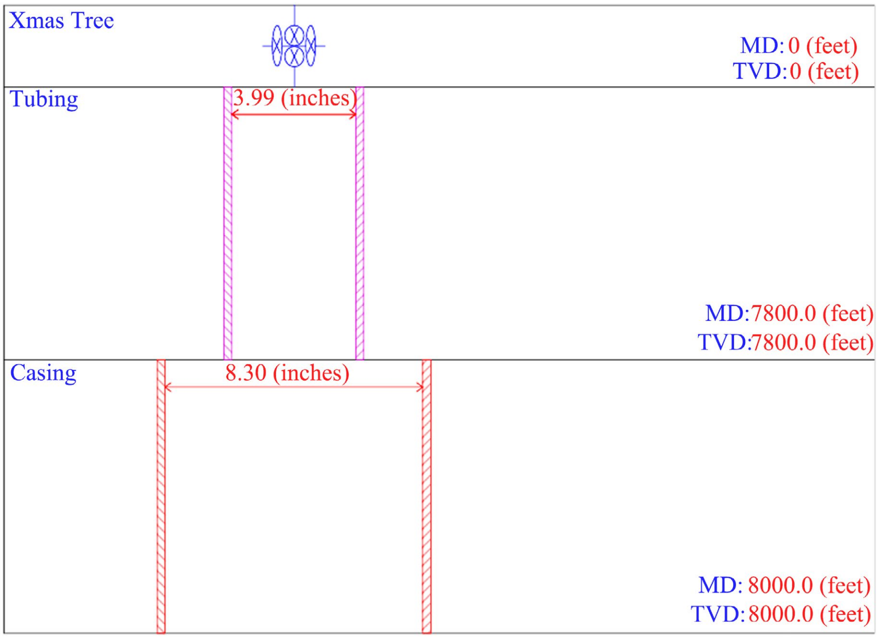

Figure 4. Illustration of the subsurface of the injection well.

4.3.2. Inflow Performance Relationship and Vertical Lift Performance Curves (IPR + VLP)

The IPR (Inflow Performance Relationship) curve is a powerful diagnostic tool that reveals how the reservoir and near-wellbore region respond to varying bottomhole pressures and CO_2 injection rates (**Figure 5**). At high bottomhole pressures, the IPR curve appears nearly linear, which represents single-phase oil flow where the production rate increases directly with pressure drawdown. The slope here is the Productivity Index (PI), which depends on factors like permeability, thickness, porosity, and near-wellbore skin. The point where the line meets the axis at zero pressure is known as the Absolute Open Flow (AOF), indicating the maximum possible oil flow.

As the bottomhole pressure reduces below the bubble point, gas starts to come out of solution. The IPR deviates downward, becoming curved, which reflects two-phase flow where oil mobility lowers and gas resistance increases. This behavior matches the well-known Vogel IPR model for two-phase flow. After implementing CO_2 injection, the entire IPR curve shifts upward and to the right, demonstrating improved reservoir support and better oil mobility. This shift yields a higher AOF and increased PI, showing that CO_2 injection not only lifts reservoir pressure but also helps reduce near-wellbore damage, likely by cleaning or reducing skin.

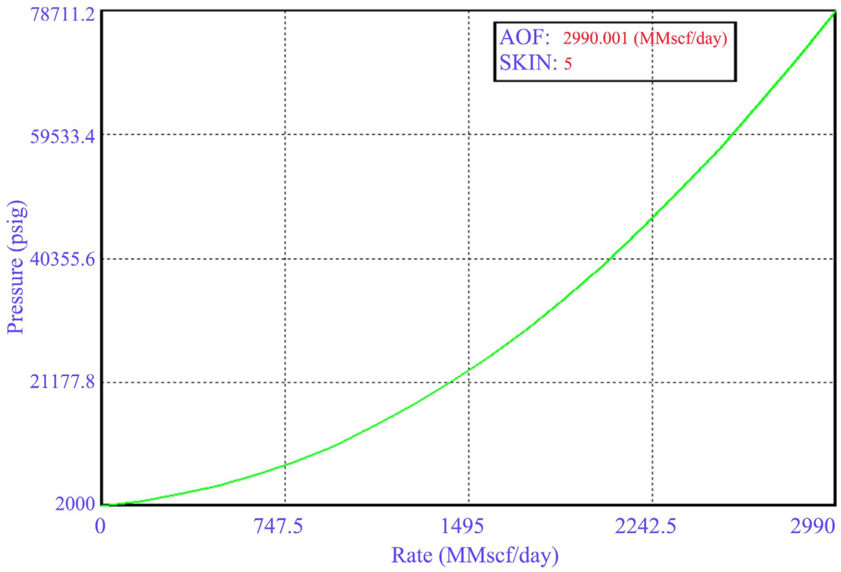

Figure 5. IPR curve for CO_2 Injection model.

Finally, at very high flow rates, the curve may flatten again due to non-Darcy flow effects, such as inertial losses, highlighting practical limits to maximum flow achievable.

In essence, the shape and position of the IPR curve from its linear high-pressure region, through the Vogel curvature, to its post-CO_2 shift indicates how CO_2 injection significantly enhances oil production in a mature reservoir.

4.3.3. Vertical Lift Performance (VLP) Curve

The VLP (tubing) curves generated in the CO_2 injection model illustrate how much bottomhole pressure is required to lift fluid to the surface at different gas injection rates. Each red curve represents a specific top-node (wellhead) pressure condition; from 1500 psig up to 6000 psig, showing the pressure drop through the tubing as gas injection increases (0 - 150 MMscf/d).

At low injection rates, the VLP curve shows relatively small pressure losses, mostly hydrostatic. As injection rates increase, the curve slopes down more steeply due to added frictional and inertial pressure losses (gravity + friction + kinetic head drop) typical in multiphase flow situations. The shape accurately reflects common behavior: flow becomes harder to lift at high rates. Any intersection between the VLP curve and the IPR curve represents the actual operating point; the achievable steady-state production or injection rate at that bottomhole pressure. Shifting the VLP upward (by increasing wellhead pressure, or using smaller tubing) would reduce intersection flow rate, while optimizing tubing or reducing surface backpressure would shift the VLP downward, increasing the achievable rate.

In this CO_2 injection model (**Figure 6**), the VLP curve demonstrates how increasing the injection rate demands greater bottomhole pressure to overcome lift resistance. It also highlights operational constraints: at very high rates, the curves flatten, meaning additional injection delivers diminishing returns due to friction and gas column weight. Therefore, to optimize the injection strategy, I can examine these curves and select an injection rate that balances reservoir capability with manageable lift pressure.

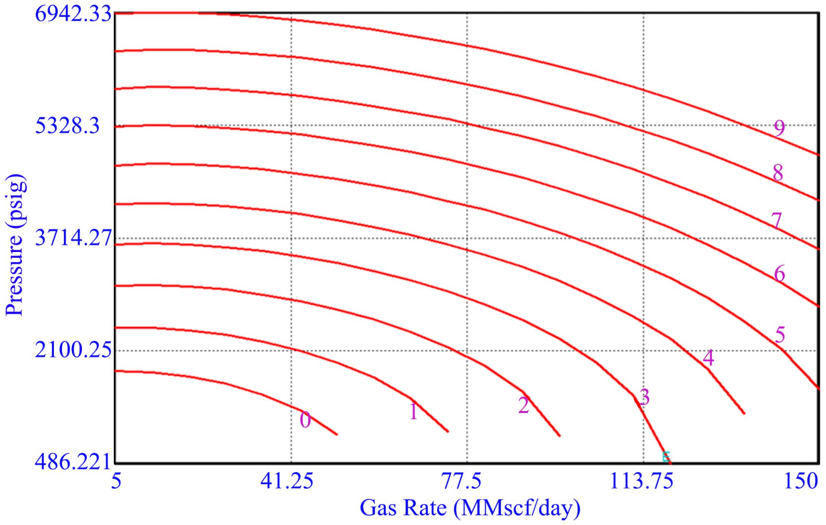

Figure 6. VLP curve for CO_2 injection model.

4.3.4. Determination of Optimum CO_2 Injection Rate—Inflow (IPR) + Outflow (VLP) Plot

Green line—Inflow Performance (IPR) Line

Red line—Vertical Lift Performance (VLP) Line

1) The IPR (Inflow Performance Relationship) curve represents reservoir behavior, which is the rate at which the reservoir can deliver CO_2 to the bottom hole at varying bottomhole pressures.

2) The VLP (Vertical Lift Performance) curve reflects the well's ability to lift that injected gas to the surface, accounting for tubing friction, hydrostatic pressure, and tool string effects (**Figure 7**).

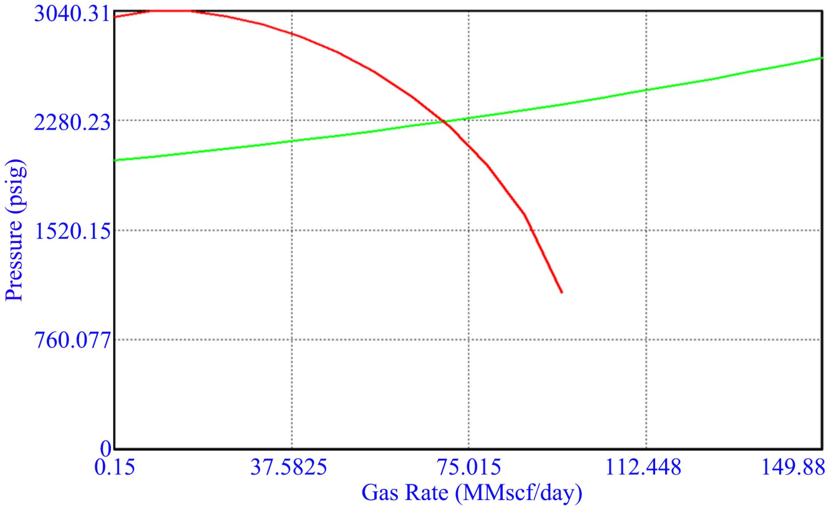

Figure 7. Optimum CO_2 injection rate.

According to nodal analysis principles, the operating (or solution) point occurs at the intersection of these two curves, where inflow equals outflow. In this plot, which occurs at approximately 70 MMscf/day of CO_2 injection at around 2287 psig bottomhole pressure.

This identifies the maximum CO_2 injection rate that can be sustained without exceeding the pressure the well can lift, ensuring system balance. Any injection rate above this curve means the wellbore can't return fluid efficiently to the surface; below it, the reservoir is underutilized.

The curve also visually shows diminishing returns: as injection rates climb, the red VLP curve slopes downward more steeply due to greater hydrostatic and frictional losses, eventually flattening, indicating lift limitations that will cap further injection.

The intersection point sets the optimum CO_2 injection rate (70 MMscf/day) that matches both reservoir supply and surface lift capability.

4.3.5. Risks of Improper Injection Rates

Too high injection rates could lead to early CO_2 breakthrough, poor sweep efficiency, and high recycling costs.

Too low injection rates lead to insufficient pressure maintenance and slow oil mobilization.

4.4. Effects of Different Gas Injection Rates on Oil Production and Recovery

The impact of CO_2 injection rates on oil production and overall recovery was assessed through a series of simulation scenarios, each with varying gas injection volumes ranging from 30 MMscf/day to 100 MMscf/day (**Figure 8**). The reservoir's response was evaluated in terms of cumulative oil recovered, breakthrough time, pressure behavior, and injection efficiency.

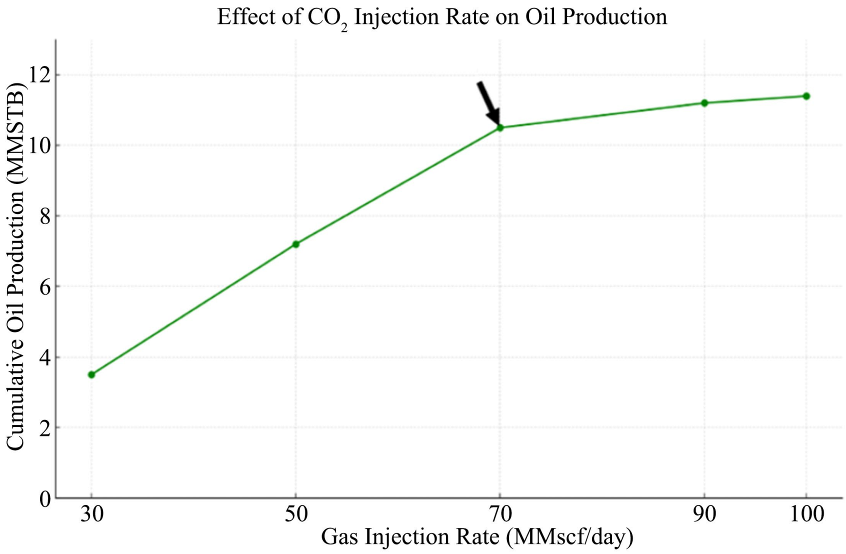

Figure 8. Graph of simulated CO_2 Injection rates against cumulative oil production.

Based on comparison between the reservoir pressure and the minimum miscibility pressure (MMP), the simulated CO_2 flood in this study operates under miscible conditions. The MMP for the reservoir fluid system is 2100 psia [26]. Historical reservoir pressures from the MBAL model range between 10,500 psig and 4300 psig, all of which are substantially higher than the MMP. Also, the corresponding injection pressure at 70 MMScfd (2287 psig) exceeds the MMP. Since miscibility is achieved whenever reservoir pressure exceeds MMP, the CO_2 injected under these conditions would form a miscible transition zone with the reservoir oil. Therefore, the displacement mechanism in this simulation is miscible CO_2 flooding, characterized by near-zero interfacial tension, oil viscosity reduction, oil swelling, and enhanced displacement efficiency.

4.4.1. Oil Recovery Trends with Varying Injection Rates

The cumulative oil recovery profiles for each CO_2 injection scenario show a clear improvement in oil recovery with increasing gas injection rate up to a certain threshold. Specifically:

1) At 30 MMscf/day, recovery increased marginally, reflecting slow reservoir pressurization and low displacement efficiency.

2) At 50 - 70 MMscf/day, a significant boost in oil recovery was observed, with faster mobilization of residual oil and improved sweep coverage.

3) Beyond 70 MMscf/day, gains in recovery began to plateau. At 90 and 100 MMscf/day, additional injected CO_2 did not proportionally increase oil production, indicating diminishing returns.

This trend highlights the existence of an optimum injection rate, identified earlier as 70 MMscf/day, where oil recovery is maximized without incurring excessive gas usage or operational inefficiencies.

4.4.2. Breakthrough Time and Sweep Efficiency

A critical observation from the simulation is the effect of injection rate on CO_2 breakthrough time. At higher injection rates (≥80 MMscf/day), breakthrough occurred significantly earlier, reducing the contact time between CO_2 and residual oil. This resulted in channeling effects and reduced areal sweep efficiency.

Conversely, moderate injection rates (50 - 70 MMscf/day) delayed breakthrough, promoting a more uniform flood front and improved contact with the oil-bearing zones. These rates ensured better volumetric displacement and reduced the likelihood of gas fingering.

4.4.3. Pressure Maintenance and Injectivity

Pressure trends across the scenarios confirm that increased gas rates restore reservoir pressure more rapidly. However, very high rates caused local over-pressurization near the injection well, posing potential fracturing risks or injectivity issues, especially in heterogeneous zones.

Table 10 illustrates the average reservoir pressure trends under each injection scenario. While all cases show pressure stabilization post-injection, the 70

MMscf/day case maintains pressure above the minimum miscibility pressure (MMP) for the longest duration, ensuring miscible CO_2-oil interaction and efficient recovery.

Table 10. Summary of injection rate effects.

Injection Rate (MMscf/day)	Cumulative Oil Recovery (MMSTB)	Breakthrough Time (days)	Pressure Maintenance	Sweep Efficiency	Efficiency Score
30	Low	Long	Weak	Poor	Low
50	Moderate	Delayed	Good	Fair	Moderate
70	High	Optimal	Strong	Good	High (Optimal)
90	Slightly Higher	Early	Overpressurized	Poor	Moderate
100	Plateaued	Very Early	Excessive	Poor	Low

This analysis confirms that 70 MMscf/day offers the most balanced injection rate, providing optimal recovery with delayed breakthrough, stable pressure support, and effective displacement, in line with nodal analysis results.

4.4.4. CO_2 Storage and Recycling Performance

Figure 9 below illustrates the cumulative CO_2 mass balance over a three-year injection period, explicitly separating the volumes permanently sequestered in the reservoir from those produced and recycled. In this study, CO_2 was injected continuously at a rate of 70 MMscf/day, corresponding to 25,550 MMscf per year and a total of 76,650 MMscf over the full study period. Applying a sequestration efficiency of 35%, representative of the fraction of injected CO_2 retained in the pore space through solubility trapping, residual trapping, and stratigraphic containment, the cumulative volume of CO_2 stored in the reservoir reached 26827.5 MMscf by the end of the third year. The remaining 65% of the injected CO_2 (49822.5) MMscf cumulatively) was produced back to the surface with the associated gas stream and subsequently recycled into the injection system. The divergence between the cumulative injected curve and the sequestered curve in **Figure 9** quantifies the reservoir's long-term carbon retention capacity. This clear partitioning of CO_2 flows indicates that a significant fraction of the injected CO_2 (over one-third) in this case, remains trapped within the formation, reflecting the study's environmental objective of reducing net atmospheric carbon emissions.

Using a conversion factor of 1 MMscf/day = 55.6 tonnes CO_2, the cumulative CO_2 volumes in the plot show a net injected volume of 4.6 million tonnes (4.26 Mt CO_2) of CO_2, a net volume of 1.50 million tonnes (1.49 Mt CO_2) of CO_2 sequestered, and a net volume of 2.78 million tonnes (2.77 Mt CO_2) produced and recycled.

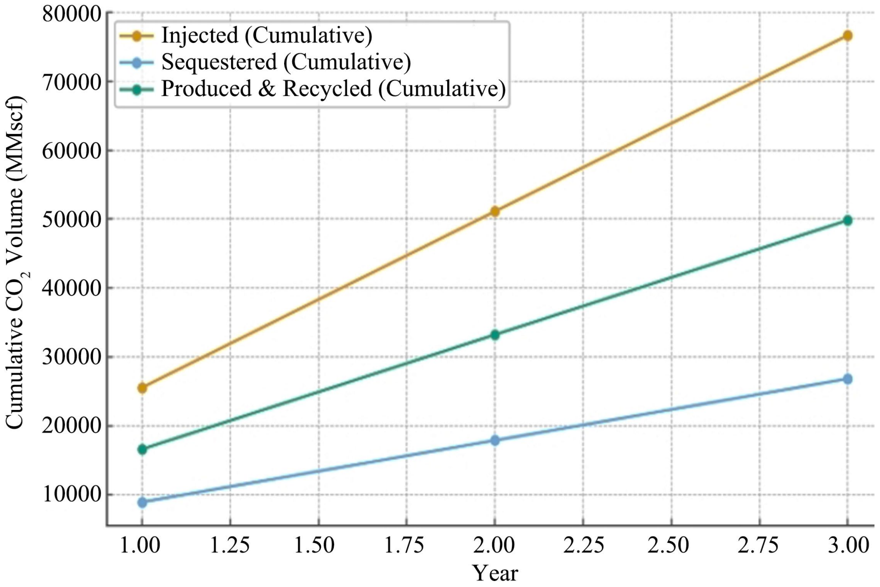

Figure 9. Graph of cumulative CO_2 injected per year versus CO_2 sequestered, and CO_2 produced/recycled.

5. Conclusions

The study investigated the application of carbon dioxide (CO_2) injection as an enhanced oil recovery (EOR) technique in a mature reservoir, using simulation tools within the Petroleum Expert Suite, notably MBAL and PROSPER. The objective was to optimize oil production and recovery efficiency while evaluating the impact of various CO_2 injection rates on reservoir performance. From the simulation results obtained, I observed that:

1) CO_2 injection significantly improves oil recovery by increasing reservoir pressure, enhancing oil mobility, and extending the productive life of a mature reservoir.

Through nodal analysis, the optimum CO_2 injection rate was determined to be 70 MMscf/day, which delivered a substantial increase in oil production with minimal operational inefficiencies. Injection rates above this threshold showed diminishing returns and posed risks such as early gas breakthrough and poor sweep efficiency. Sensitivity analysis on injection rates reinforced that a balanced and controlled CO_2 injection strategy yields optimal recovery with economic and operational viability.

2) The analysis of Inflow Performance Relationship (IPR) and Vertical Lift Performance (VLP) curves demonstrated how CO_2 injection alters the inflow dynamics and lift behavior, improving both productivity index and flow assurance.

3) While the simulation identified 70 MMscf/day as the optimal CO_2 injection rate, it is important to note that this value is specific to the reservoir model used in this study, and not a universally applicable value; however, the generalizable contribution of this study is the methodology and optimization workflow, which can be applied to other fields using their own reservoir-specific data.

4) The CO_2-EOR process evaluated in this study not only enhances oil recovery but also contributes to emissions reduction by storing a significant portion of the injected CO_2 within the reservoir. Over the three-year injection period, approximately 4.26 Mt CO_2 was injected, of which 1.49 Mt CO_2 remained permanently sequestered while 2.77 Mt CO_2 was produced and recycled. This closed-loop utilization of CO_2 minimizes atmospheric emissions, converts a waste-stream greenhouse gas into a productive resource, and aligns the enhanced oil recovery process with broader climate-mitigation goals.

Recommendations

Based on the findings and limitations encountered in this study, the following recommendations are proposed for practical application. These suggestions aim to enhance the efficiency and understanding of CO_2-enhanced oil recovery (EOR) in mature reservoirs, especially in the context of field-scale implementation and the integration of alternative modeling strategies.

1) Adopt CO_2 Injection at Optimum Rate: Operators should implement CO_2 injection at or near the determined optimum rate to maximize oil recovery without incurring operational inefficiencies or early gas breakthrough.

2) Include Surface Facilities Modeling in Future Simulations: Although this study focused on subsurface behavior, future work should incorporate surface facilities and pipeline networks to capture the full-field operational dynamics and economic assessments.

3) Utilize More Detailed Geological Models: For more accurate predictions, detailed reservoir characterization and 3D geological modeling should be integrated into the simulation to reflect heterogeneities and fracture behavior.

4) While the simulation identifies a technically optimal CO_2 injection rate, the final selection for field implementation must also consider economic factors. The cost of CO_2 supply, compression, and recycling, as well as the prevailing and forecasted oil prices, significantly influence the economic viability of the flood. Higher injection rates increase operating costs and may not justify the incremental oil recovery when oil prices are low; hence, practical field applications must balance technical performance with profitability. This requires optimizing the injection rate not only for maximum recovery but also for economic returns, ensuring that the cost of CO_2 acquisition, compression, and recycling is outweighed by the revenue generated from cumulative oil production.

Conflicts of Interest

The authors declare no conflicts of interest regarding the publication of this paper.

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