Review

A Review of CO$_2$-Enhanced Oil Recovery with a Simulated Sensitivity Analysis

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Abstract: This paper reports on a comprehensive study of the CO$_2$-EOR (Enhanced oil recovery) process, a detailed literature review and a numerical modelling study. According to past studies, CO$_2$ injection can recover additional oil from reservoirs by reservoir pressure increment, oil swelling, the reduction of oil viscosity and density and the vaporization of oil hydrocarbons. Therefore, CO$_2$-EOR can be used to enhance the two major oil recovery mechanisms in the field: miscible and immiscible oil recovery, which can be further increased by increasing the amount of CO$_2$ injected, applying innovative flood design and well placement, improving the mobility ratio, extending miscibility, and controlling reservoir depth and temperature. A 3-D numerical model was developed using the CO$_2$-Prophet simulator to examine the effective factors in the CO$_2$-EOR process. According to that, in pure CO$_2$ injection, oil production generally exhibits increasing trends with increasing CO$_2$ injection rate and volume (in HCPV (Hydrocarbon pore volume)) and reservoir temperature. In the WAG (Water alternating gas) process, oil production generally increases with increasing CO$_2$ and water injection rates, the total amount of flood injected in HCPV and the distance between the injection wells, and reduces with WAG flood ratio and initial reservoir pressure. Compared to other factors, the water injection rate creates the minimum influence on oil production, and the CO$_2$ injection rate, flood volume and distance between the flood wells have almost equally important influence on oil production.

Keywords: CO$_2$-EOR; miscible recovery; immiscible recovery; effective factors; review study; numerical modelling

1. Introduction

Oil is one of the most important substances to modern human civilization. It is still the major source of energy for the world, and is also a critical resource for the petrochemical industry, which is responsible for many household products and medicines. However, in recent years, many oil fields around the world have started to show a decline in production and may not be able to sustain the world's demands [1].

Oil production is generally conducted in three main stages: primary, secondary and tertiary. Primary oil recovery refers to oil production that is reliant on the natural difference in pressure between the reservoir pressure and the production well pressure, also called the "natural drive" of the

reservoir. Pumps may be used to increase production when the natural drive starts to slow. Secondary oil recovery is generally used when primary oil production methods are no longer effective. Usually, fluid (usually water) or gas is pumped into the reservoir to increase the reservoir pressure, which acts as an artificial drive. Typically, primary and secondary oil recovery results in a recovery efficiency of about 33% of original oil in place (OOIP) or the total amount of oil present in the reservoir, as shown in Figure 1 [2].
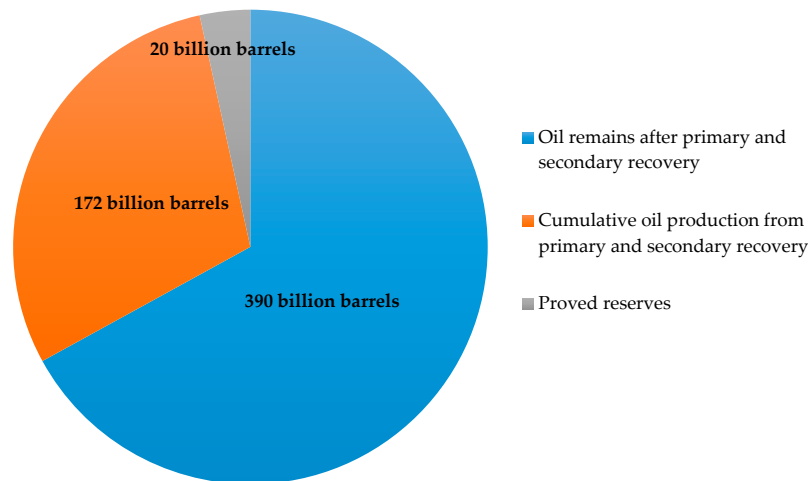
Figure 1. Oil production ability by primary/secondary recovery techniques [3].

Enhanced or tertiary oil recovery usually takes place near the end of the lifespan of the reservoir in order to further increase the total amount of oil recovered, and can be achieved by many techniques including gas injection, chemical injection, ultrasonic stimulation, microbial injection or thermal recovery [4,5]. These recovery mechanisms have been well explained by Lake et al. [4], including conventional (natural flow and water flood) and enhanced (thermal, chemical, solvent and other) recovery processes. Green and Willhite [5] used frontal-advance theory to explain the transport of chemical species in the oil displacement process during the chemical injection EOR process and according to them, continuous injection of chemicals (e.g., polymer, surfactant, or a miscible solvent) is not an economically feasible option due to the high cost. In the case of CO_2-EOR, oil mixed with CO_2 gas has much increased mobility and therefore the injection of CO_2 into oil reservoirs has significant ability to enhance oil production [6]. This is because injecting CO_2 extracts heavy hydrocarbons from the oil phase and accelerates the oil mobility through oil swelling and reducing oil viscosity [7]. Therefore, EOR through CO_2 injection in oil fields (also called CO_2-EOR) significantly increases oil production from reservoirs. CO_2-EOR has been recognized as the second largest EOR process in the world, after the thermal processes used in heavy oil fields [8]. According to Green and Willhite [5], thermal recovery processes are the most advanced EOR processes that contribute significantly to daily oil production in the world. Generally, thermal recovery consists of cyclic stream injection (drive and soak) and in-situ combustion processes, and can be used for a wide range of reservoir conditions, including shallow and deep [5], and in-situ combustion is the only thermal recovery process that can be used in deep, high-pressure reservoirs [5].

Global warming is a major issue for the world, as increased amounts of CO_2 and other greenhouse gases in the atmosphere have resulted in increases in sea levels and changes in climate [9–13]. As a result, in addition to the injection of naturally occurring CO_2 (traditionally, the CO_2 used in CO_2-EOR comes from CO_2 natural reservoirs), significant attention has recently been given to the investigation of the potential of the use of CO_2-EORs as a long-term anthropogenic CO_2 storage application, because unless the CO_2 used is from anthropogenic origins, there are no environmental benefits in the CO_2-EOR process. One such application has recently been reported from Canada, where a large demonstration

project, called the Weyburn CO_2-EOR project using anthropogenic CO_2 was launched, and has been successfully using the CO_2-EOR technique to securely store a large quantity of CO_2 captured from anthropogenic sources [14]. According to Gozalpour et al. [14], although the CO_2-EOR technique can be used to permanently store CO_2 in geological formations under the right reservoir conditions, the use of anthropogenic CO_2 for the process may be subject to considerable economic restrictions.

CO_2-EOR is not a new technology. It has been frequently used in the United States since the mid-1980s, in the Permian Basin, West Texas and Eastern New Mexico. In 2008, there were over 100 CO_2-EOR projects that were collectively responsible for 250,000 barrels per day of incremental oil. The reasons for this success are mainly significant government subsidies, the availability of cheap supplies of CO_2 and an extensive CO_2 pipeline network. However, the technology has only recently started to be used outside the USA in the past 10 years.

The aim of this paper is to provide a detailed study of the carbon dioxide enhanced oil recovery (CO_2-EOR) process, a comprehensive literature review and numerical modelling. For the numerical modelling, the CO_2-Prophet numerical modelling software was used to conduct a comprehensive to investigate the factors affecting the CO_2-EOR process, in order to identify the optimum conditions to recover a maximum amount of oil.

2. A Comprehensive Review of the Enhanced Oil Recovery Process

2.1. Major Oil Recovery Techniques in the Field

Basically, two types of oil recovery techniques are used in the petroleum industry: miscible and immiscible [15]. The process of "miscibility" happens in the miscible oil recovery process and "solubility" happens in the immiscible oil recovery process. Miscibility is the mixing of multiple substances in all proportions and creates a homogeneous phase without the existence of an interface and solubility is the mixing of limited amounts of one substance with another substance, with creating an interface between two phases [6,16,17]. Typically, oil reservoirs with more than $25°$ API oil gravity and located at more than 915 m depths are selected for miscible oil recovery. Therefore, miscibility can only be achieved under certain pressure and temperature conditions and is not viable for every oil field [17]. However, immiscible oil recovery can be applied to moderately heavy oil reservoirs and shallower light oil reservoirs, which do not meet the requirements for miscibility, being located at less than 915 m depths or with oil gravities between $17.5°$ and $25°$ API [18].

2.1.1. Miscible Oil Recovery

Miscible oil recovery can be applied only at pressures higher than the minimum miscibility pressure (MMP), which can be estimated using a slim tube test [19] or available correlations [20]. Therefore, to achieve the highest oil recovery, the reservoir must be capable of withstanding pressure greater than the MMP [21]. One of the main advantages of CO_2 compared to other types of oil enhancing gases such as methane and nitrogen is the significantly lower MMP value. As a result, CO_2 can be used to enhance the miscible oil recovery process in a wide range of oil reservoirs [21]. There are two basic types of miscibility mechanisms in the oil recovery process: first contact miscibility and multiple contact miscibility. First contact miscibility means that the solvent and oil become miscible when they first make contact, and the displacement of light oil using propane or LPG falls into this category. Multiple contact miscibility achieves miscibility through several different contacts, and most of the high pressure gas-enhanced oil recovery belongs to this category [22]. CO_2 cannot achieve first contact miscibility in most oil reservoirs within a reasonable range of pressures and needs multiple contacts, in which components of the oil and CO_2 transfer back and forth until the formation of a homogeneous phase through the processes of vaporization/condensation [21,23]. Jarrell et al. [24] explain this CO_2 miscibility process using the transition zone between the injection and production well. According to them, the mass transfer between oil and CO_2 creates a completely miscible zone in

the oil reservoir without any interface that eventually develops a transition zone that is miscible with oil in the front and with CO_2 in the back.

However, some problems occur with miscible flooding. One is the precipitation of asphaltenes, which may hinder fluid flow and significantly reduce mobility, even in low amounts [25]. This happens more frequently in light oils. Asphaltene deposition starts with precipitation, where solid particles come out of solution, then the solid particles clump together and grow larger, finally being deposited onto a solid surface [25]. This may then lead to formation damage due to the blockage of crucial fluid flow paths, which leads to irreversible damage of the reservoirs. For instance, an oil sample taken from a Malaysian oil reservoir had an asphaltene content of 0.42% and demonstrated precipitation ranging from 0.11% to 0.31% [26] and a Bangestan reservoir of the Ahwaz oilfield containing 18.2% asphaltenes demonstrated severe asphaltene deposition, which completely stopped production in a slim-tube test, due to severe blockage of the capillary tube [26].

2.1.2. Immiscible CO_2-EOR Process

The immiscible CO_2-EOR technique is dominated by the process of oil swelling and its viscosity reduction. It is well established that when CO_2 is dissolved in oil, the oil swells and its viscosity reduces and therefore, injection of CO_2 into the reservoir should clearly enhance immiscible CO_2-EOR. However, since the degree of oil swelling and its viscosity depends on the CO_2 solubility in oil, solubility is often the most influential factor for the effectiveness of CO_2-EOR, particularly for low pressure applications, as has been experienced in a pilot test in Turkey [27,28]. Therefore, detailed descriptions of CO_2 solubility in oil and the corresponding oil swelling and viscosity are given below.

(1) CO_2 Solubility in Oil

Saturation pressure, temperature and oil gravity are the primary factors affecting CO_2 solubility in oil. The solubility of CO_2 in crude oil generally increases with pressure and API gravity and decreases with temperature. However, at temperatures less than the CO_2 critical temperature (i.e., when CO_2 is sub-critical), oil composition and liquefaction pressure also become effective [29]. According to Jarrell et al. [24], CO_2 dissolution in oil causes oil viscosity to be significantly reduced and oil hydrocarbon to be extracted, resulting in enhanced oil recovery, and super-critical CO_2 can extract hydrocarbon components from oil more easily than sub-critical CO_2.

Emera and Sarma [29] have developed highly accurate correlations for CO_2 solubility in oil and the corresponding oil swelling and viscosity using a genetic algorithm technique, and their results have been validated using published experimental data. These correlations can be used for pressures up to 34.5 MPa, oil molecular weights up to 490 g, oil viscosities up to 12,000 cp, and temperatures up to 140 °C. This has also been independently verified by Al Jarba and Al Anazi [30]. Two correlations have been developed for CO_2 solubility in oil for temperatures greater than the critical temperature of CO_2 (under any pressure condition) and less than the critical temperature (under pressures less than CO_2 liquefaction pressure).

For temperatures greater than the critical temperature of CO_2 under any pressure condition:

$$CO_2 \text{ Solubility } \left(\frac{\text{mol}}{\text{mol}} \right) = 2.238 - 0.33y + 3.23y^{0.6474} - 4.8y^{0.25656} \tag{1}$$

where $y = \gamma \left(\frac{T^{0.8}}{P_s} \right) \exp \left(\frac{1}{MW} \right)$.

For temperatures less than the critical temperature (under pressures less than the CO_2 liquefaction pressure):

$$CO_2 \text{ Solubility } \left(\frac{\text{mol}}{\text{mol}} \right) = 0.033 - 1.14y - 0.7716y^2 + 0.217y^3 - 0.02183y^4 \tag{2}$$

where $y = \gamma \left(\frac{P_s}{P_{\text{liq}}} \right) \exp \left(\frac{1}{MW} \right)$, γ is the oil specific gravity (oil density at 15.6 °C), T is the temperature (°F), P_s is the saturation pressure (psi), P_{liq} is the CO_2 liquefaction pressure at the specified temperature (psi), MW is the oil molecular weight, and μ_i is the initial dead oil viscosity at the specified temperature (cp).

(2)   Oil Swelling

Oil swelling can be represented using a swelling factor:

$$\text{Oil swelling factor} = \left(\frac{\text{Volume of } CO_2 \text{ saturated at current temperature}}{\text{Volume of oil at current temperature}} \right) \quad (3)$$

This depends on the CO_2 solubility and size of the oil molecules [29]. Oil swelling with CO_2 solubility can range from 10% to 50% [22]. According to Emera and Sarma [29], the oil swelling factor can be derived from the following equations depending on the oil's molecular weight:

For oil molecular weight $\geqslant 300$,

$$\text{Swelling factor} = 1 + 0.3302y - 0.8417y^2 + 1.5804y^3 - 1.074y^4 + 0.0318y^5 - 0.21755y^6 \quad (4)$$

For oil molecular weight <300,

$$\text{Swelling factor} = 1 + 0.48411y - 0.9928y^2 + 1.6019y^3 - 1.2773y^4 + 0.48267y^5 - 0.06671y^6 \quad (5)$$

where $y = 1000 \left\{ \left(\frac{\gamma}{MW} \right) [CO_2 \text{solubility}]^2 \right\}^{\exp\left(\frac{\gamma}{MW} \right)}$, γ is the oil specific gravity (oil density at 15.6 °C) and MW is the oil molecular weight.

(3)   Oil Viscosity

Oil viscosity is highly dependent on the CO_2 solubility and pressure, and decreases with saturation pressure up to liquefaction pressure, and after liquefaction, the viscosity starts to increase again due to the effect of pressure and oil compressibility [29]. According to Emera and Sarma [29] oil viscosity can be derived from the following equation:

$$\text{Oil viscosity} = y\mu_i - 10.8 \left(\frac{CO_2 \text{ solubility}}{\mu_i} \right) \quad (6)$$

where $y = x^{-0.74}$, $x = \left[\mu_i \left(\frac{P_s}{\mu_i} \right)^{0.2} \right]^{\frac{\gamma}{CO_2 \text{solubility}}}$, P_s is the saturation pressure (psi), and μ_i is the initial dead oil viscosity at the specified temperature (cp).

2.2. How Does CO_2 Injection Enhance Oil Recovery?

It is important to have a clear understanding of the processes underlying CO_2-EOR for successful field application. In addition to maintaining or increasing the reservoir pressure, which provides the "artificial drive" for oil production, CO_2 injection is responsible for other effects, which enhance oil recovery. According to Rojas and Ali [31] and Tunio et al. [8], there are four major processes which are responsible for CO_2-enhanced oil recovery: (1) oil viscosity reduction; (2) oil swelling; (3) oil and water density reduction; and (4) vaporization and extraction of portions of oil. To explain these processes, carbon dioxide has high solubility in oil's hydrocarbons, which causes the oil to swell and consequently reduces the oil's viscosity and density. In addition, there is some water in the oil reservoir and therefore, carbon dioxide injection causes this water density also to be reduced, which eventually causes both water and oil densities to become similar, resulting in the reduction of the gravity segregation effect [7]. However, the importance of the each of these processes depends on the pressure and temperature of the reservoir, as shown in Figure 2 [32]. According to the figure, there is a

clear distinction between the miscible and immiscible processes, the miscible process occurring at high temperatures and pressures, and the immiscible process at lower pressure and temperature conditions. The roles of various reservoir and operational parameters on the mechanism and the displacement behaviour of the CO_2-EOR process have been explained by Jarrell et al. [24]. According to them, continuous CO_2 injection, continuous CO_2 injection followed by water, conventional water-alternating gas (WAG) followed by water, trapped WAG and WAG followed by gas are the main CO_2-EOR recovery methods, and the applicability of each depends on the reservoir geology, fluid and rock properties, timing relative to water flooding and well-pattern configuration.
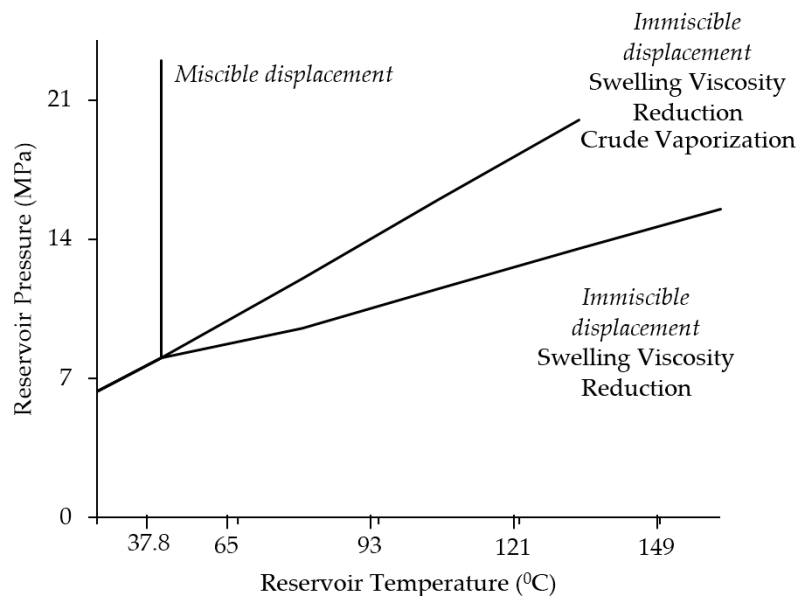

Figure 2. Effect of reservoir temperature and pressure on CO_2—enhanced oil recovery [32].

2.3. Economics of CO_2-EOR

The initiation of a CO_2-EOR project needs capital costs for drilling or reworking wells for both injection and production, the establishment of a CO_2 recycling plant and corrosion-resistant field production infrastructure, the laying of CO_2 capturing pipelines and the purchase of CO_2. The economics of CO_2-EOR are therefore highly dependent on several basic factors, including the prevailing oil prices, the reservoir conditions, and the availability of cheap sources of CO_2. As a result, the economics of CO_2-EOR vary from country to country, depending on the availability of CO_2 and existing pipeline systems. For example, in the case of USA there are many cheap sources of CO_2 from natural sources (\$US 1–2 mmscf/day) and a readily available CO_2 pipeline system, which causes the CO_2-EOR application to be economically attractive [33,34].

The prevailing oil price also plays a very important role in the economy of the CO_2-EOR process. Figure 3 shows how the number of CO2-EOR projects in USA varied with the oil price during the 1980–2008 period. Assuming an average oil price of US\$70/barrel, a US government study gave a reasonable cost estimation for CO_2-EOR, and according to Table 1 [35], the estimated profit is US\$30–40 per barrel before any tax is applied. Although the increasing oil price has significantly improved the profits from oil production, CO_2-EOR is still considered to be a risky investment by many operators due to the significantly high up-front cost and problems related to the time required to achieve considerable oil production, which may be significantly delayed by the risk of unexpected geologic heterogeneity [36].
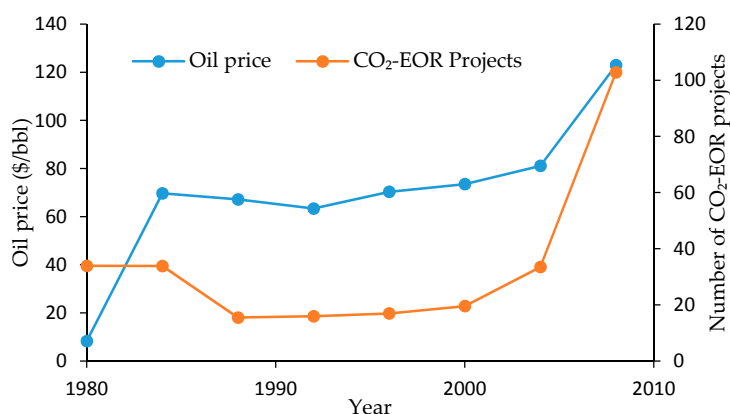
Figure 3. CO$_2$-EOR projects and oil prices in the US during 1980–2008 period [37].

Table 1. Costs involved in CO$_2$-EOR [35].

Cost Category	Cost US$/barrel
CO$_2$ costs	15
Well/Lease operation and management	10–15
Capital costs	5–10
Total (without any tax included)	30–40

2.4. Environmental Impacts of CO$_2$-EOR

A life-cycle analysis of enhanced oil recovery in the Permian Basin concluded that CO$_2$-EOR offers a huge CO$_2$ storage capacity, minimal process emissions, and is almost carbon-neutral when comparing the net storage potential and gasoline emissions from the additional oil extracted [38].

Another life-cycle analysis of a Norwegian enhanced oil recovery project, which took into account global warming potential, acidification, human toxicity, eutrophication, wastes and resources, concluded that CO$_2$-EOR offers significant environmental benefits compared to conventional oil production, with a weighted score difference of about 150% [39]. One of the important advantages of sequestering CO$_2$ in oil reservoirs is the large storage capacity. A study has identified about 139 Giga tonnes of CO$_2$ storage capacity in global oil reservoirs [2] which is significant, considering that roughly 34 billion tonnes of CO$_2$ were emitted in 2011 and the cumulative CO$_2$ emissions during 2000 to 2011 were around 420 billion tonnes [40]. Furthermore, oil reservoirs have been trapping oil inside them for millions of years and would thus form good CO$_2$ "traps", as well as having extensive operating histories, which is highly important in terms of safety [41]. Although CO$_2$ storage in reservoirs has less uncertainty than CO$_2$ storage in aquifers [42], there are still significant knowledge gaps in terms of the assessment of the risk of the underground storage of CO$_2$ [43].

2.5. Field Enhanced Oil Recovery Projects

The miscible CO$_2$-EOR technique has been frequently used all over the world and has recovered significant amounts of additional oil from reservoirs. One is the Permian Basin, located in New Mexico and West Texas. This reservoir had a capacity of 95.4 billion oil barrels, of which only 35% could be recovered by primary and secondary recovery. The remainder needed the enhanced oil recovery technique, which was started using CO$_2$ injection in 1970 [18]. The current oil production rate in the basin is around 2200 mmcfp/day [44]. The largest CO$_2$-EOR project in Canada was started in 2000 in the Weyburn Basin, which had around 1.4 bbls (billion barrels) crude OOIP. This is the largest CO$_2$ storage project in the world, and has been used to store around 13 million tonnes of CO$_2$ to date. It is expected to recover an additional 130 million barrels of oil from this field by miscible or near-miscible displacement with CO$_2$ [45].

Currently, typical miscible CO_2-EOR efficiencies achieved are quite low (about 10% of OOIP), but still higher than immiscible CO_2-EOR. However, the miscible CO_2-EOR technique has the potential to obtain up to about around 20% of OOIP, which has been successfully achieved in certain basins in the USA by using alternative practices such as closer spacing between injection and production wells [2,46].

On the other hand, many field projects have successfully used immiscible the CO_2-EOR technique to enhance oil recovery. One is the Jilin oil field located in Changshen, China. In this project, four pilot tests of oil recovery used the immiscible CO_2-EOR technique and it is expected to obtain an extra 5%–10% of OOIP. These reservoirs had a pressure of about 20 MPa, temperatures of around 100 °C. CO_2 injection in one of the pilot projects (Hei59) achieved a CO_2 solubility of 64% (mol/mol), an oil swelling of around 47% and viscosity reduction of around 63.2%, with an average depth of 2400 m, a continuous CO_2 injection rate of 30–40 tonnes/day, and using a hexagonal configuration with one injection well surrounded by six production wells. The primary challenges include low permeability of less than 10 md, poor reservoir quality and continuity and high water saturation [47].

In south-eastern Turkey, there are a number of immiscible CO_2-EOR projects. The oil in this field has high molecular weight and the miscibility pressure is much higher than the reservoir pressure. For these reasons, only immiscible displacement was applicable, which was achieved through oil swelling created by the injected CO_2 and the corresponding viscosity reduction [28]. The first application was in 1986 in the Bati Raman heavy-oil field, which contains low API gravity oil (about 12) at a depth of 1300 m, which had low reservoir energy and unfavourable oil properties (high viscosity). The oil–water contact was at around 600 m below sea level. 65 active wells with a spacing of around 500 m were producing 1500 STB/day of oil at a reservoir pressure of 1800 psi. Before the CO_2 injection, the reservoir pressure had dropped to 400 psi. A gas drive mechanism was used instead of direct injection, as the injected gas remained in the wellbore vicinity, which greatly increased pressure around the wellbore. Cumulative CO_2 injected was about 124 mmscf/day with a corresponding 34 million STB (stock tank barrel) of incremental oil. However, CO_2 was also produced from the well, which was then recycled using recycling compressors. It was expected that primary production would only recover about 2% of OOIP. However, through the use of immiscible CO_2-EOR, the project has sustained economic production levels for over 10 years and has successfully recovered about 6% of OOIP [28].

Another field project that has used the immiscible CO_2-EOR technique to achieve an extra recovery of 8.6% of OOIP is the Ikiztepe oil field. This field contains low gravity (10° to 12° API) and high viscosity (936 cp) oil at an average depth of 1350m, with average porosity of 15%–23% and average permeability of 50–400 md. CO_2 was injected in an inverted 5 spot pattern in a 200 m × 200 m grid at a pressure of 2500 psi. It was found that the CO_2 injectivity increased from 0.9 to 3.8 mmscf/day/psi in 2 years after "huff-and-puff" CO_2 injection, where CO_2 was directly injected for short periods of time, then stopped and then restarted. The improvement in injectivity is probably due to improved gas permeability with increased gas saturation. Cumulative CO_2 injected was about 339.42 mmscf/day with a corresponding 17,284 bbls of oil. In this project, the primary factor influencing recovery efficiency was the solubility of CO_2 in oil [28].

In addition, four immiscible CO_2-EOR pilots have been implemented in Trinidad. The reservoir consisted of thick sands containing medium-gravity oil (API gravity of 17–29). It was predicted that immiscible CO_2-EOR would result in extra oil recovery of about 2%–8% of OOIP [48].

2.6. Opportunities for CO₂-EOR Process Improvement

Although the current CO_2-EOR process has typical incremental oil recoveries of only 10%–20%, it can be significantly improved by the following measures [46].

2.6.1. Increase in the Amount of CO_2 Injected

Traditional practice has used only about 0.4 HCPV (hydrocarbon pore volume) of CO_2. Using a computer model developed for a field reservoir in the San Joaquin Basin, it was found that it is theoretically possible for 67% of the OOIP to be recovered by injecting 2.0 HCPV of CO_2 [44]. However, in order do this, CO_2 should contact a larger proportion of the residual oil, instead of being limited to certain areas with high CO_2 saturation. Comberiati and Zammerilli [49] also observed a significant positive influence of CO_2 slug size on oil production, basically due to the increased amount of CO_2 with increased slug size (Figure 4a). However, according to these researchers, increase of pore volume or slug size causes the operating cost to be proportionally increased. They also showed the ability to enhance the CO_2-EOR process by using liquid CO_2 injection rather than gas [49].
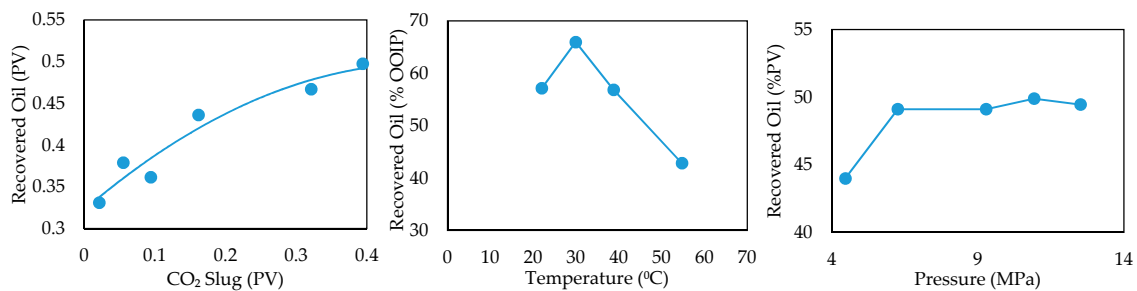
Figure 4. Effects of reservoir and injecting CO_2 properties on oil recovery [49].

2.6.2. Innovative Flood Design and Well Placement

Innovative flood design and well placement may be able to ensure that a higher proportion of the residual oil can be contacted by the CO_2. Some innovations include isolation of poorly-swept reservoir intervals for CO_2 injection, altering injection and production well patterns, using horizontal wells, using physical or chemical diversion materials to "divert" the CO_2 into poorly-swept area, and using much closer well spacing [50].

2.6.3. Improving the Mobility Ratio

By using chemicals that increase the viscosity of the injected water, the mobility ratio can be improved [51].

2.6.4. Extending Miscibility

By the use of miscibility-enhancing agents, the minimum miscibility pressure can be reduced, which will allow miscible recovery to be possible for reservoirs previously unsuitable for miscible CO_2-EOR. The "real-time" flood performance measurement technique also has been identified as an area of improvement [35].

In addition, reservoir properties such as pressure and temperature also significantly affect the CO_2-EOR process, though they are difficult to control. Regarding the reservoir temperature effect, Comberiati and Zammerilli [49] observed a maximum oil recovery closer to the critical temperature of CO_2 (31.8 °C) at 7.98 MPa constant pressure (Figure 4b). According to these researchers, at the critical temperature CO_2 converts to the super-critical state. After that, further increase of temperature causes more CO_2 to be vaporized from the oil phase and therefore, less CO_2 mixes with oil, which reduces oil recovery. In the case of reservoir pressure on oil production, Comberiati and Zammerilli [49] observed a generally increasing trend of oil production with increasing pressure, and the miscibility pressure was observed at around 12.5 MPa reservoir pressure for any temperature condition for the tested reservoir (Figure 4c).

3. A Numerical Study to Investigate the Effective Factors for the CO_2-EOR Process

3.1. Model Development

A 3-D numerical model was developed in the next stage of the study to examine the enhanced oil recovery process and factors affecting it. In order to do this, the CO_2-Prophet numerical modelling software, which has been widely used in many engineering applications to simulate fluid transport in porous media, was used [17,52,53]. In this software, streamlines are first generated for fluid flow between the injection and production wells, and then displacement and recovery calculations are performed along the stream tubes [54]. The selected model grid block with the injection and production well locations are shown in Figure 5. The selected model parameters are shown in Table 2. As shown in the table, the Cooper Basin's (the largest on-shore oil and gas field in Australia) properties have been used to develop the model.
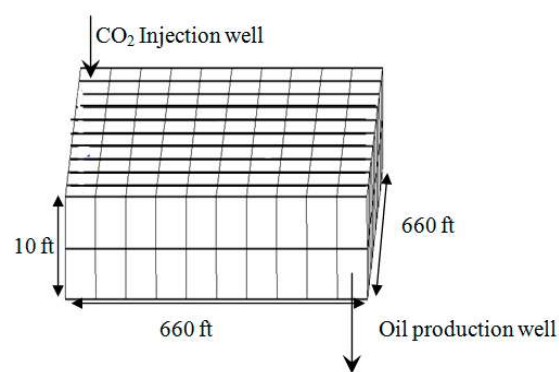
Figure 5. The selected model grid block with injection and production well locations.

Table 2. Model parameters [47].

Variable	Value
Dykstra-Parsons Coefficient	0.7
Reservoir Temperature	137 °C
Average Reservoir Pressure	22 MPa
Porosity	0.15
Initial oil saturation	54%
Minimum Miscibility Pressure	19 MPa
Oil Viscosity	0.14 cp
Oil Formation Volume Factor (swelling factor)	2.10 rb/STB
Solution Gas-Oil Ratio (solubility)	1444 scf/STB
Oil Gravity, API	30
CO_2 Specific Gravity (relative to air)	1.5189
Water Viscosity	0.2 cp
Water Salinity	2000 ppm

3.2. Model Simulation

Model simulation was carried out in two main phases to investigate: (1) the ability of the pure CO_2; and (2) the WAG process to enhance the oil recovery process and to investigate the effects of CO_2/water injection rate, flood volume (HCPV), temperature, pressure, WAG ratio, and well pattern on oil production. 15 years of flood injection was considered for all cases, with the exception of the first case, the effect of CO_2 injection rate on oil production. In this case, it was possible to check the effect for only two years, because very high CO_2 injection rates caused the simulator to fail after around two years, probably due to reservoir failure with such a high CO_2 volume.

Before conducting any model simulation, the developed model was first validated. However, the model could not be validated using Cooper Basin data due to the missing parameters. Therefore, the applicability of the CO_2-rophet software for the simulation of the EOR process was tested by validating the model using data from the SACROC project in the Permian Basin, Texas [55]. Figure 6 shows the comparison between predicted model data and actual SACROC project data. According to the results, the developed model can successfully re-produce the actual data in the SACROC project, showing the applicability of CO_2-Prophet software in simulating the EOR process. The applicability of the CO_2-Prophet simulator for CO_2-EOR process has also been shown by Saini [56].
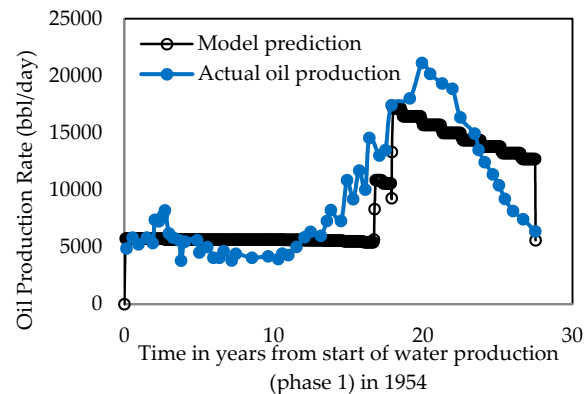

Figure 6. Comparison of predicted and actual oil production rates.

(1) Pure CO_2 Injection

Pure CO_2 injection was first performed through the injection well given in Figure 5 and the effects of CO_2 injection rate and amount and reservoir temperature on oil recovery were investigated.

(2) Effect of CO_2 Injection Rate

The CO_2 injection rate was changed from 5 mmscf/day to 20 mmscf/day while maintaining all other parameters as constants (temperature at reservoir temperature and pressure at reservoir pressure). The variation of total oil production with CO_2 injection rate within the first two years of injection was observed (Figure 7).
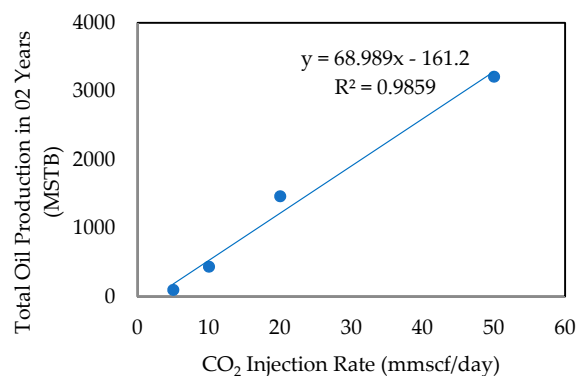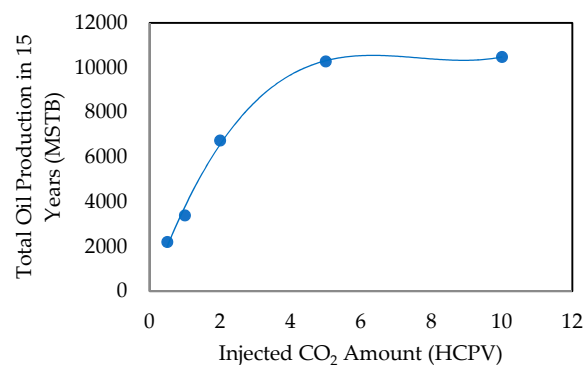

Figure 7. Variation of oil production with CO_2 injection rate.

As shown in the figure, an almost linear relationship between CO_2 injection rate and oil production was observed, possibly due to the fact that increasing CO_2 injection rate creates a higher driven force, which causes more CO_2 molecules to penetrate the voids in the oil reservoir, creating more contacts between oil and CO_2 molecules. This linearly increasing oil production with CO_2 injection rate shows

the benefits of as high a CO_2 injection rate as possible to reach maximum oil production. However, such a high injection rate will also cost more in terms of CO_2 cost and injection facilities, and it is important to take into account the availability of CO_2. In addition, maintaining a high CO_2 injection rate may cause the reservoir pore pressure to be drastically increased and consequently the reservoir cap rock to be damaged, causing the injected CO_2 to back-migrate into the atmosphere after some time of CO_2 injection.

(3)　Effect of Amount of CO_2 Injected

After checking the CO_2 injection rate, the total amount of CO_2 injected was changed to 0.5, 1, 2, 5 and 10 HCPV (hydrocarbon pore volume), keeping all the other parameters constant, and the corresponding oil production variation was observed and recorded for 15 years of injection (Figure 8).
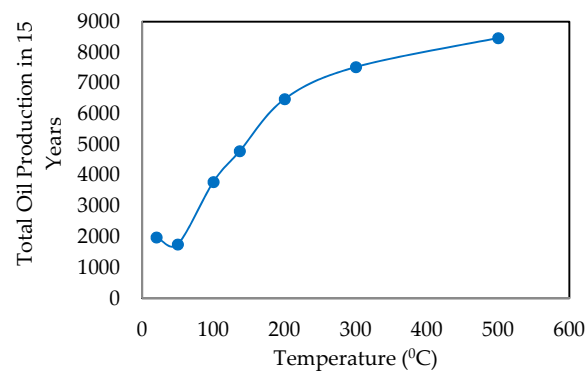

Figure 8. Variation of oil production with amount of injected CO_2.

According to Figure 8, there is a significant increment in oil production with the increase of total injected CO_2 from 0.5 HCPV to 10 HCPV. This is consistent with the findings of Comberiati and Zammerilli [49], who also showed an increment in oil production with increasing flood volume. This oil production increment with increasing CO_2 volume arises because, with the increased amount of injected CO_2, all the CO_2-induced oil production enhancing mechanisms (viscosity reduction, promotion of swelling, density reduction of oil and water and vaporization and thus extraction of portions of oil [7,57]) are accelerated. However, according to the figure, past 5 HCPV, there is no further benefit in oil production, probably because almost all the possible oil has been recovered by the 5 HCPV CO_2 injected volume. According to Ghedam [58], the reservoir fluid and CO_2 normally reach a one-contact miscible state when the CO_2 concentration is greater than 60 mol%, at which the swelling factor varies between 1.25–1.6. This variation in swelling factor allows the CO_2 to greatly swell oil, which eventually enhances the oil recovery. However, according to Jarrell et al. [24], adequate purity in the injecting CO_2 (90%–98%) is required, particularly for miscible oil recovery. In addition to the swelling factor, oil viscosity reduction caused by the injecting CO_2 is also favourable for oil recovery, and according to Yongmao et al. [59] and Srivastava et al. [60], injection of CO_2 into an oil reservoir may cause oil viscosity in the reservoir to be reduced by around 10%–70%, significantly enhancing oil productivity. Importantly, Azzolina and co-workers' [61] statistical analysis of 31 CO_2-EOR candidates clearly shows the dominant role of the injecting CO_2 volume on oil production enhancement. These existing findings therefore support the predicted relationship between the injected CO_2 amount and total oil production in 15 years in the present study (Figure 8).

(4)　Effect of Temperature

The reservoir temperature was then changed from 20 °C to 500 °C while keeping all other parameters constant (CO_2 injection rate of 5 mmscf/day and pressure at reservoir pressure) to check the effect of temperature on oil production (Figure 9).

According to Figure 9, oil production appears to be first reduced with increasing temperature up to around 50 °C and then starts to increase with increasing temperature. The reduction of oil production with increasing temperature from 20 to 50 °C is consistent with the findings of Comberiati and Zammerilli [49], who also observed a reduction of oil recovery after the critical temperature of CO_2 (31.8 °C) up to 55 °C. According to these researchers, after the critical temperature, CO_2 starts to vaporize from the oil phase, producing less contact with oil. However, these researchers checked this temperature effect only up to 55 °C. Figure 9 clearly shows the inaccuracy of that statement for high temperature conditions (>100 °C), where oil production is significantly increased with increasing temperature. Increasing the temperature causes the kinetic energy of CO_2 molecules to increase, which creates a more active CO_2 phase [62,63]. This may cause a higher degree of contact of CO_2 molecules with residual oils in the reservoir, which increases oil production. It is probable that the effect of kinetic energy increment and the corresponding increment in CO_2 mobility with increasing temperature is much higher than the CO_2 vaporizing effect under high temperature conditions (>100 °C). This also exhibits the importance of an appropriate numerical model to study the extreme conditions in oil recovery, which are normally difficult to achieve under laboratory experimental conditions, such as CO_2-EOR under very high pressure and temperature conditions.

Figure 9. Variation of oil production with reservoir temperature.

As explained by Green and Willhite [5], increasing the reservoir temperature reduces its oil viscosity. This eventually accelerates oil productivity, because low viscous oil can more easily and quickly move towards the production well, which is consistent with the findings of the present study given in Figure 9. However, according to Shaw and Bachu [64], reservoirs with low temperatures and high pressures are more favourable for the CO_2-EOR process compared to high temperature and pressure reservoirs, because both CO_2 and oil densities and viscosities are similar under such conditions, which minimizes the fingering and gravity-override effect and therefore enhances oil recovery. These findings show the complexity of the influence of this particular parameter on oil production and the in-depth knowledge required of the subject before coming to a final conclusion.

If these three effects on oil production are now compared, 100% increment in CO_2 injection rate (5 to 10 mmscf/day), injected CO_2 volume (0.5 to 1 HCPV) and temperature (50 to 100 °C) causes oil production to be generally enhanced by 344%, 65% and 39%, respectively (note that here the general trend has been considered for all the cases). This implies that, compared to other factors, the CO_2 injection rate has the maximum influence on oil production in the pure CO_2 injection process. This is due to the fact that increasing the injection rate not only provides a higher volume of CO_2, but also offers a higher driving force for CO_2 molecules to contact oil molecules.
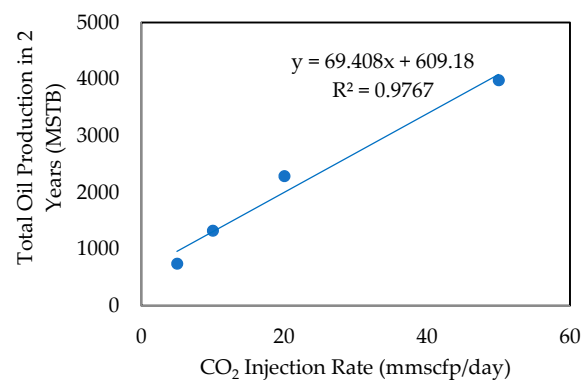
(5) WAG CO_2 Injection

In the next stage of the study, water was injected alternately with CO_2 into the reservoir to enhance oil production using a 2000 bbl/day water injection rate, 5 mmscf/day CO_2 injection rate and

a 0.5 WAG flood ratio (0.5 WAG flood ratio = 50% of the time water is injected and 50% of the time CO_2 is injected). In this case, a parametric study was also conducted to investigate the effects of CO_2 and water injection rates, total injected flood volume in HCPV, WAG flood ratio, and initial reservoir pressure and flood well pattern on oil production.

(6)　Effect of CO_2 Injection Rate

The CO_2 injection rate was first considered and changed from 5 mmscf/day to 20 mmscf/day, while maintaining all the other parameters constant (temperature at reservoir temperature, pressure at reservoir pressure, water injection rate of 2000 bbl/day, WAG flood ratio of 0.5). The observed variation of oil production with CO_2 injection rate is shown in Figure 10.

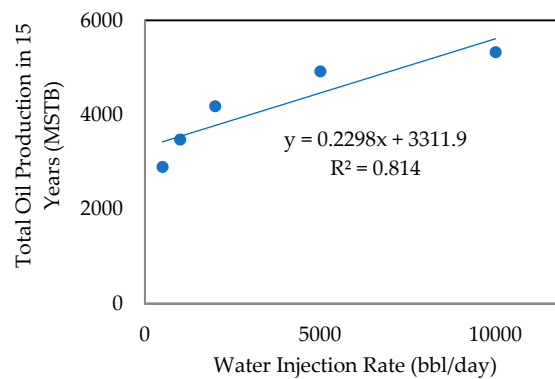**Figure 10.** Variation of oil production with CO_2 injection rate (WAG).

According to the figure, similar to pure CO_2 injection, there is an almost linear relationship between the CO_2 injection rate and the oil production rate. As mentioned earlier, the higher CO_2 injection rate offers a higher driving force to produce a greater amount of oil from the reservoir with increasing degree of contact between oil and CO_2.

In the present study, the model was run gradually increasing both CO_2 and water injection rates from 1 to 80 mmscf/day and from 100 to 15,000 bbl/day, respectively, and the injection rates were increased until cap rock/reservoir rock failure, and the failure point was identified by the sudden oil recovery enhancement observed at one stage of each injection rate. This is because a sudden increment can only occur through sudden permeability enhancement in the reservoir/cap rock mass with the initiation of fractures when the water/CO_2 injection-induced pore pressure exceeds the reservoir rock/cap rock fracturing pressure. The sudden productivity enhancements were observed when the CO_2 and water injection rates were at around 75 mmscf/day and 12,000 bbl/day, respectively. Therefore, only CO_2 and water injection rates below the failure condition were used for the sensitivity analysis to identify the effects of pure injection rates.

(7)　Effect of Water Injection Rate

In order to check this, the water injection rate was changed from 2000 bbl/day to 10,000 bbl/day while maintaining all other parameters constant (temperature at reservoir temperature, pressure at reservoir pressure, CO_2 injection rate of 5 mmscf/day, WAG flood ratio of 0.5). Figure 11 shows how the oil production varied with water injection rate.

As can be seen in the figure, there is a clear increment in oil production with increasing water injection rate. However, the effect is much less than the effect of CO_2 injection rate. This is because, although water is injected alternately with CO_2 during the WAG process to create a more favourable environment to enhance oil production, CO_2 plays the major role. Therefore, the greater influence of CO_2 injection rate on oil production was expected.

Figure 11. Variation of oil production with water injection rate (WAG).

(8)　WAG Flood Ratio

The WAG flood ratio is the amount of water relative to CO_2 when the CO_2 is 1, and a WAG flood ratio of 1:1 means that 50% (on a reservoir volume basis) of the total fluid injection is water and 50% is CO_2. In order to check the effect of the WAG flood ratio on oil production, the WAG flood ratio was changed from 1:10 to 5:1 while maintaining all other parameters constant (temperature at reservoir temperature, pressure at reservoir pressure, CO_2 injection rate of 5 mmscf/day and water injection rate of 2000 bbl/day) and the corresponding effect on oil production was investigated (Figure 12).
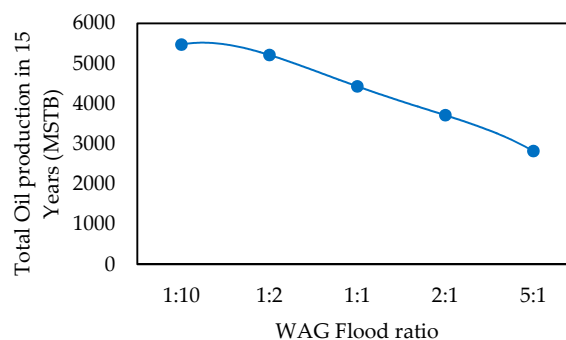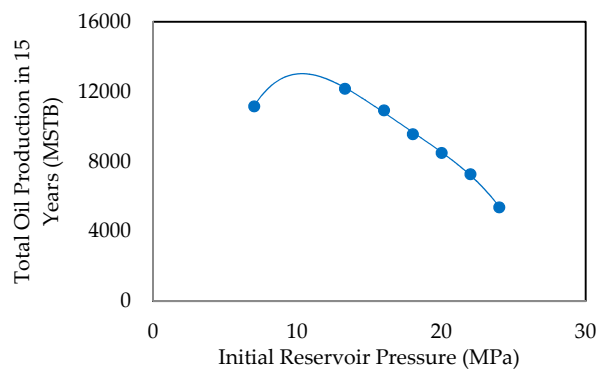

Figure 12. Variation of oil production with WAG flood ratio.

According to the figure, oil production reduces with increasing WAG flood ratio, showing the benefit of less volume allocation for water injection. This also relates to the greater influence of CO_2 on the oil enhancement process compared to that of water. This has been explained by many researchers [51,65,66]. According to Jackson et al. [65], oil recovery efficiency clearly reduces with increasing WAG flood ratio, and Ghedan [58] has clearly shown the importance of carefully selecting the CO_2-WAG flood ratio, as an unnecessarily high WAG flood ratio may cause the oil production to be delayed with the injection of a greater proportion of water that acts as a barrier for CO_2 to reach the oil, reducing the displacement efficiency of the CO_2. Many laboratory studies have also found similar effects of WAG flood ratio on sweep efficiency [67,68].

(9)　Initial Reservoir Pressure

The effect of initial reservoir pressure on oil production was then investigated by changing the initial reservoir pressure from 7 MPa to 24 MPa while maintaining all other parameters constant (temperature at reservoir temperature, CO_2 injection rate of 5 mmscf/day, water injection rate of 2000 bbl/day). Figure 13 shows how oil production varied with initial reservoir pressure.

Figure 13. Variation of oil production with initial reservoir pressure in WAG process.

It is interesting to see an increasing trend of oil production at the beginning (from 7.0 to 13.3 MPa) and a reduction of oil production after that (13.3 to 24 MPa) with increasing reservoir pressure. The initial oil production increment with increasing reservoir pressure is likely to be related to the minimum miscible pressure (MMP) of the reservoir. It is probable that by around 13 MPa the selected reservoir reaches its MMP, which leads to initiation of the miscible oil recovery process, resulting in an increment in oil production. This has also been observed by Comberiati and Zammerilli [49] by around 12.5 MPa, which was the MMP of the reservoir they studied. However, according to Figure 13, a further increase of initial reservoir pressure after reaching the MMP in very deep formations causes the oil production to be significantly reduced. This is because, at higher initial reservoir pressures, there is less "room" for CO_2 to be injected into the reservoir, causing a reduction in CO_2 injectivity, which in turn leads to reduced oil production, which is important in miscible CO_2 floods. This observation is consistent with the findings of Rivas et al. [69] and Thomas [51]. Rivas et al. [69] found an increment in average oil production with reservoir pressure up to 1.3 MMP, however, it started to reduce with pressure with further increase of reservoir pressure (>1.3 MMP). According to these researchers, this is related to the correlation between CO_2 formation factor and live oil viscosity. According to Bachu et al. [70], Kovscek [71], Taber et al. [72] and Shaw and Bachu [64], the reservoir pressure required to screen favourable oil pools for CO_2-EOR is generally above 7.6 MPa, which is at least 1.38 MPa greater than the reservoir MMP (reservoir pressure/MMP ratios as low as 0.95 are acceptable). These findings also show the importance of selecting a reservoir located at a suitable depth for the CO_2-EOR process, which should not be too shallow or too deep.

(10)   Effect of Total Injected Volume in HCPV

In order to check this, the total injected amount of water and CO_2 in HCPV was changed from 0.2 HCPV to 2 HCPV, while maintaining all other parameters constant (temperature at reservoir temperature and pressure at reservoir pressure) and the effect on oil production was observed (Figure 14).

The figure shows that oil production increases with increasing total injected flood volume (HCPV). However, the effect is diminished by increasing the injected volume past 2 HCPV. As mentioned earlier, it is probable that almost all of the possible oil has been recovered by the 2 HCPV flood volume in the WAG process. Similar to pure CO_2 injection, there are many additional costs associated with increasing the amount of CO_2 injected, and this needs to be weighed against the expected benefit of injecting the extra CO_2.
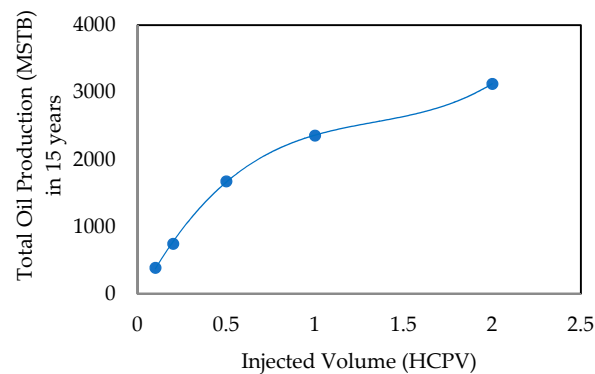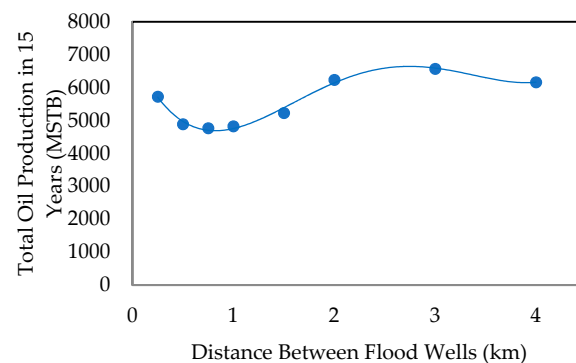
Figure 14. Variation of oil production with injected flood volume (HCPV) in WAG process.

(11)   Effect of Injecting Well Pattern

The effect of the pattern of injection (flood) wells on oil production was then checked and the results are shown in Figure 15. According to the figure, increasing the distance between the flood wells causes oil production to be first reduced and then increased. This is because increasing the distance between the wells affects the reservoir productivity in two different ways. On one hand, increasing the distance between wells causes the amount of CO_2 injected into a particular area in the reservoir to be reduced, which in turn slows the CO_2-ECBM process in that area. On the other hand, reduction of the distance between the wells means that injection wells are located at closer distances. Injecting high-pressure CO_2 into the reservoir causes a high pore pressure area to develop around the injection well, and injecting CO_2 into the reservoir from an adjunct area may therefore not be effective, due to the already developed high pore pressure created in that area by the former injection well. This greatly reduces the CO_2/water injectibility into the reservoir from the second well and also creates a reduction of injectibility in the former well. This implies that maintaining sufficient distance between the injection wells is necessary for effective CO_2 injectibility into the reservoir, which in turn affects the oil productivity from it. Therefore, the combined effect of these contradictory effects, (1) CO_2 injection-induced reservoir pore pressure development causes CO_2 injectibility limitation; and (2) the amount of possible CO_2 injection with a greater number of wells at closer distances, governs the final influence of the distance between the wells. According to Figure 15, when the distances between the wells are as small as less than 1.5 km, the negative effect of pore pressure development is dominant, and when there is a sufficient distance among the wells, the latter effect (the greater amount of CO_2 injection into the reservoir through more wells) is dominant. However, reservoir productivity is not affected by the well distance when the wells are located longer distances apart (>3 km), in which case the influence of each well seems to be independent.

Figure 15. Variation of oil production with distance between injecting wells.

If all of these influences on oil production are now considered, in general a 100% increment in CO_2 injection rate (5 to 10 mmscf/day), water injection rate (500 to 1000 bbl/day), injected flood (CO_2 plus water) and volume (0.5 to 1 HCPV) cause oil production to be enhanced by 78%, 20% and 40%, respectively. However, a 100% increment in WAG flood ratio (1:1 to 2:1) and initial reservoir pressure (10 to 20 MPa) cause the oil production to be reduced by 32% and 54%, respectively. This implies that, compared to other factors, the water injection rate has the minimum influence on oil production, and the CO_2 injection rate and flood volume are the most important influences on oil production. This minimum influence of water injection rate on oil production was expected, because the only purpose of water injection in the WAG process is to increase the reservoir pressure to miscible pressure. Interestingly, the effect of CO_2 injection rate on oil production is much higher for pure CO_2 injection compared to the WAG process (more than four times higher). The influence of the distance between the flood wells is not as significant as other factors.

4. Conclusions

A comprehensive study of the CO_2 injection-enhanced oil recovery process and the factors affecting it was conducted by undertaking a detailed literature review and developing an advanced numerical model.

According to the literature review, there are basically two types of oil recovery techniques in the field: miscible and immiscible. Oil reservoirs with more than 25° API oil gravity and located at more than 915 m depth are selected for miscible oil recovery and others are selected for immiscible recovery. The process of "miscibility" happens in the miscible oil recovery process and "solubility" happens in the immiscible oil recovery process. Of the two processes, miscible oil recovery has greater ability to produce additional oil from the reservoir. When CO_2 is injected into the reservoir, it increases the reservoir pressure, swells the oil, reduces its viscosity and density, and vaporizes the oil hydrocarbons. All of these processes cause both miscible and immiscible oil recovery to be enhanced. However, miscible oil recovery can only be achieved at pressures higher than the minimum miscibility pressure (MMP) and therefore WAG (water injected alternately to gas) technique is used in the field to increase the reservoir pressure to MMP. One of the main advantages of CO_2 compared to other types of oil-enhancing gases is the significantly lower MMP value, meaning that CO_2 can be used for a wide depth range of oil reservoirs. The economics of CO_2-EOR depend on the prevailing oil prices, the reservoir conditions, the availability of cheap sources of CO_2 and existing pipeline systems, and therefore vary from place to place. To date, miscible and immiscible CO_2-EOR techniques have been widely applied in oil fields in the USA, Canada, China, Turkey and some other countries, leading to the recovery of a considerable amount of additional oil. The amount recovered could be significantly further increased by applying promoting methods, such as increasing the amount of CO_2 injected, applying innovative flood design and well placement, improving the mobility ratio, extending miscibility and controlling the reservoir depth and temperature.

In the next stage of the study, the CO_2-Prophet software was used to develop a 3-D numerical model to study the effective factors for the CO_2-EOR process. Pure CO_2 injection with no water injection was considered first. A linearly increasing oil production trend with increasing CO_2 injection rate was observed. The effect of injected volume of CO_2 (in HCPV) on oil production was then checked and increasing oil production with the injected volume of CO_2 (HCPV) was observed. In terms of reservoir temperature, although there was a reduction of oil production with increasing reservoir temperature from the critical temperature of CO_2 to around 50 °C, a further increase of temperature caused the oil production to be significantly increased.

The WAG process was then considered, where water is injected alternating with CO_2. A significant improvement in oil production was observed with increasing CO_2 and water injection rates, and the effect is much higher for CO_2 [24]. The flood ratio was then studied and a reduction of oil production with increasing WAG flood ratio was observed, proving the benefit of having less time allocated to water injection. Subsequently, the effect of initial reservoir pressure was checked. Although oil

production exhibited an increasing trend with increasing reservoir pressure until it reached the minimal miscible pressure (MMP), further increase of pressure caused the oil production to be reduced. The effect of the total amount of flood injected into the oil reservoir was then checked and it was found that an increase in HCPV injected led to significant increases in oil production. The effect of injection well pattern on oil production was finally examined and it was found that increased distance between the injection wells causes more oil production due to the reduction of the coincidence of pressure contours created by each well.

Author Contributions: Andrew Koay, Tharaka Dilanka Rathnaweera and Mandadige Samintha Anne Perera did the numerical modelling work and drafted the manuscript. Ashani Savinda Ranathunga contributed to draft the manuscript. Xavier Choi mentored the modelling work. Ranjith Pathegama Gamage reviewed the final paper and made important suggestions and recommendations for paper revision.

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Abbreviations

The following abbreviations are used in this manuscript:

EOR	Enhanced Oil Recovery
HCPV	Hydrocarbon pore volume
mmcf/day	Million cubic feet per day
bbl/day	Barrel per day
STB	Stock tank barrel
MMP	Minimum miscibility pressure
MSTB	Million stock tank barrels
OOIP	Original oil in place
PV	Pore volume
WAG	Water alternating gas

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