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MASTER'S THESIS

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ABSTRACT

The objective of this project is to maximize oil recovery and the CO_2 stored during CO_2-EOR. To reach that goal there are two important things to be achieved: gas production rate reduction and the oil production rate improvement. To attain the co-optimization, the following CO_2 injection approaches were compared: CO_2 continuous injection, WAG, Continuous water injection over continuous CO_2 injection, and intermittent water injection over continuous CO_2 injection. The comparison was done by using a commercial simulation program CMG GEM 2015. It was learned from this work that the water injection over the CO_2 injector would offer the best way to increase the CO_2 stored. It was found that increasing the water injection rate and injection length would increase the CO_2 stored in the reservoir due to the reduction in gas-oil mobility ratio. However, the oil recovered would be reduced due to the increase of water-oil mobility ratio. This project presented the importance of carefully adjusting the water injection configuration during the lifetime of CO_2-EOR on achieving the co-optimization goal. Compared to the continuous CO_2 injection scenario, the highest oil recovery case resulted in the following: 4.46% OOIP oil recovery increase, 8% more CO_2 stored, and reduction in CO_2 utilization factor from 5.22 tCO_2/Sm^3 oil to 4.15 tCO_2/Sm^3 oil. The reduction in the CO_2 utilization factor shows that this approach would be economically and practically attractive.

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1. INTRODUCTION

The rise in the Earth's average temperature is an issue that world leaders have to mitigate. The Paris Agreement in December 2015 (FCCC, 2015) agreed to hold the global average temperature to well below 2 °C above pre-industrial levels and to pursue efforts to limit the temperature increase to 1.5 °C above pre-industrial levels. To achieve this goal, the amount of CO_2 in the atmosphere need to be maintained below 530 ppm in the year of 2100. The correlation between CO_2 content in the atmosphere and global temperature increase derived from IPCC's 5th Assessment Report of Working Group III (2014) can be seen in

Table 1-1. In April 2016 at Mauna Loa Observatory (2016) the CO_2 concentration is observed to be 407.57 ppm. As shown in Figure 1-1, the CO_2 concentration would surpass the 2 degree target if there is no mitigation action taken.

Table 1-1- CO_2-eq concentration and the impact in global temperature increase

CO_2-eq Concentrations in 2100 (ppm)	**Temperature change in 2100 (^{0}C)**
430-480	1.5-1.7
480-530	1.7-1.9
530-580	2.0-2.2
580-650	2.1-2.3
650-720	2.3-2.6
720-1000	3.1-3.7
1000	4.1-4.8

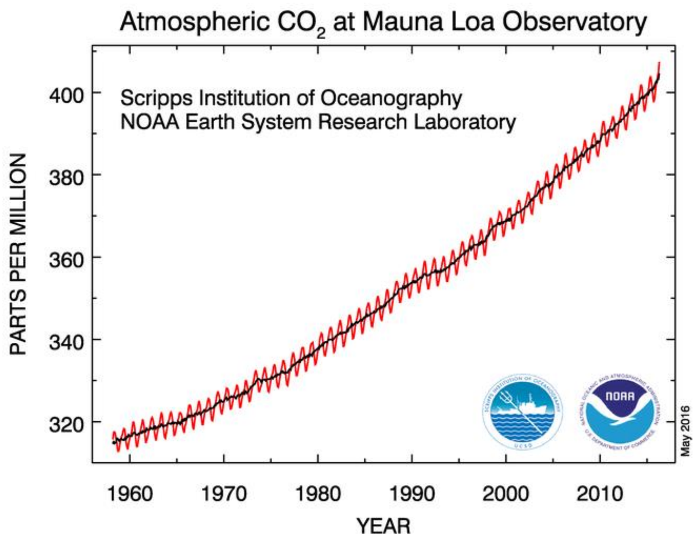
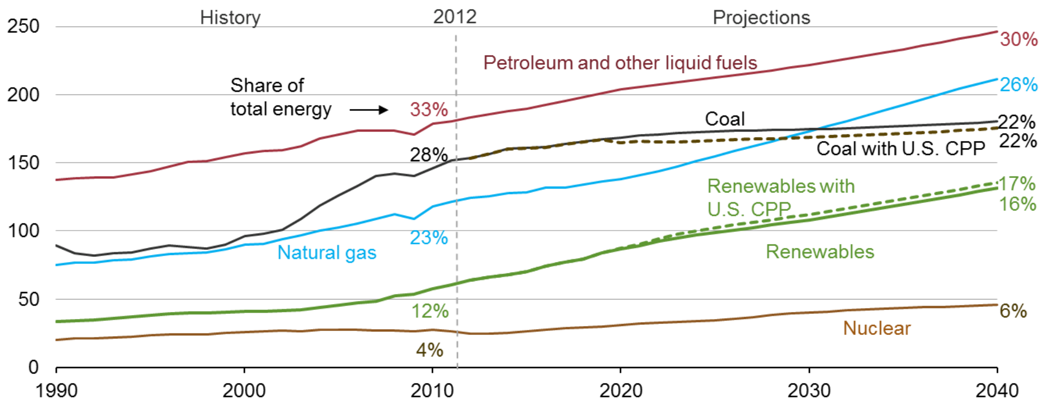


Figure 1-1- Atmospheric CO_2 concentration at Mauna Loa Observatory from March 1958 to April 2016. Source:Tans (2016)

IPCC (2014) stated that there are a very limited scenario where the 2 degree target can be achieved without BCCS, it means that CCS is a significant part of mitigating the climate change.

It was also predicted that without CCS the mitigation cost will be +138%, compared to with CCS scenario which ranged from around +10% to +60%.

It can be observed in Figure 1-2, as the need for clean energy increase, the energy share of renewables and natural gas is expected to be increasing rapidly. However, “Petroleum and other liquid fuels” consumption trend still shows the increasing volume demand and maintain its position as the main source of energy in the world. The world will need an increasing amount of oil to be produced in order to fulfill its energy demand.



Source: EIA, International Energy Outlook 2016 and EIA, Analysis of the Impacts of the Clean Power Plan (May 2015)

Figure 1-2- Energy Consumption Forecast from Adam Sieminski (2016)

As the world needs to decrease CO_2 concentration in the atmosphere, and the world demand an increasing volume of oil. As such, an EOR method that could co-optimize between maximizing oil production and maximizing the amount of CO_2 stored would be desired. In this project, an effort to conduct CO_2-EOR that could achieve that goal was pursued.

1.1 PROJECT OBJECTIVES AND TASKS

The world energy demand will continue to increase in which petroleum oil continues to be the main energy source. Meanwhile, the global effort to reduce the amount of CO_2 in the atmosphere shows the importance of CO_2 storage to reach the 2 degree target. As such, the objective of this project is to study on how to co-optimize CO_2-EOR for maximizing the oil recovery and increase the CO_2 stored. Several approaches were addressed in this thesis. The used tool for this study was CMG-GEM 2015 reservoir simulator.

The first task was to investigate how to reduce the CO_2 production. Several approaches were assessed: CO_2 continuous injection, WAG, continuous water injection into the top reservoir layer and continuous CO_2 injection, and intermittent water injection and CO_2 injection. Then, by using the injection approaches above, a number of different injection strategies were explored to maximize the oil recovery while also increasing the CO_2 stored.

The second task is to conduct sensitivity studies. The investigated parameters are the injection rate and the injection interval. From the sensitivity study, the positive and negative impacts of each changes on the incremental oil recovery and the CO_2 stored were realized. The promising cases were further investigated for co-optimization.

The third task is to compare the oil recovery increase, the CO_2 stored, and the CO_2 utilization factor of the various injection methods and configurations. The oil recovery increase and the CO_2 utilization factor decrease would serve as the economic justification for selecting the case.

1.2 METHODOLOGY

A literature review was first conducted to better understand CO_2 EOR and CO_2 storage. Publications from credible organizations such as IEA, IPCC, World Bank, NETL, etc. were studied to understand the most current facts, trends, insights, and projections of current climate issues, energy issues, CO_2 EOR, and CCS. Publications from various journals and papers are also studied to better understand the co-optimization of CO_2-EOR and CO_2-storage.

As simulation is the main tool of analysis in this project, a reservoir model was constructed. The simulation model then was subjected to the sensitivity analysis of various injection approaches, injection rates, and injection strategies. The learning from the sensitivity analysis would be the basis of optimization in order to be able to co-optimize CO_2-EOR and CO_2-storage.

Lastly, the selected approach for co-optimization was subjected to four reservoir sensitivity analysis: reduction in gas mobility, reduction in reservoir permeability, increase in reservoir anisotropy, and lastly reduction in water salinity.

2. LITERATURE REVIEW

A conventional CO_2 optimization project would be aiming at maximizing oil production at an optimized rate of CO_2 injection. This conventional view is due to the CO_2 gas is seen as an operating cost. Therefore, the aim of reducing the total amount of CO_2 gas utilized while optimizing oil production is an economically justified aim.

In this project however, the objective is to maximize oil recovery while maximizing the CO_2 stored during CO_2-EOR. To reach this goal, a literature research to justify the motivation of such aim is required. Also, a literature research that served as the technical foundation on how to effectively achieve the goal of this project is required. By having a strong motivation and adequate technical proficiency, this project report will offer a robust study on how to achieve the co-optimization of CO_2-EOR and CO_2-storage.

2.1 CO_2 impact on climate changes

The fact that GHG emission as the cause of climate change is well accepted. The clear correlation between GHG emission, temperature increase, and sea level changes can be seen in Figure 2-1 and Figure 2-2.

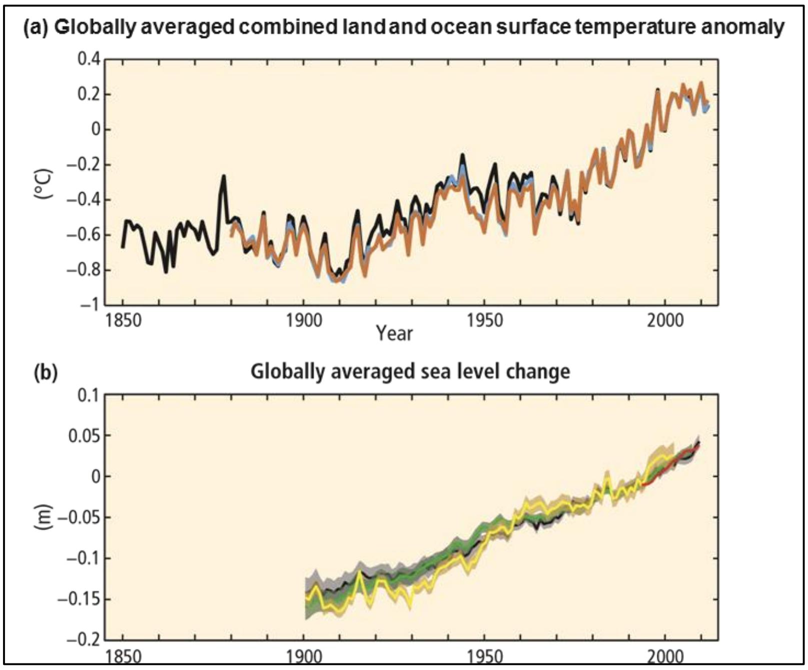


Figure 2-1- Temperature (a) and sea level (b) increases over the years (IPCC, 2014)

From Figure 2-2 it can be observed that the quantity of CO_2 emission is the highest among other GHG emission. Thus, the urgency to mitigate CO_2 emission in the atmosphere is the issue that the author would like to address. Figure 2-3 shows that anthropogenic CO_2 emission rate is accelerating rapidly in the last 50 years, which would accelerate the increase of CO_2 concentration in the atmosphere.

The IPCC (2014) projected Anthropogenic GHG emissions by respecting the changes in population size, economic activity, lifestyle, energy use, land use patterns, technology, and climate policy. Those factors are the basis of modelling The Representative Concentration Pathways (RCPs) in order to produce the following projections: GHG emissions and atmospheric concentrations, air pollutant emissions, and land use. Four RCPs scenarios are presented: RCP2.6 for strong mitigation aims to keep likely below 2°C, business as usual scenario RCP6.0 and RCP8.5, and intermediate scenario RCP4.5.

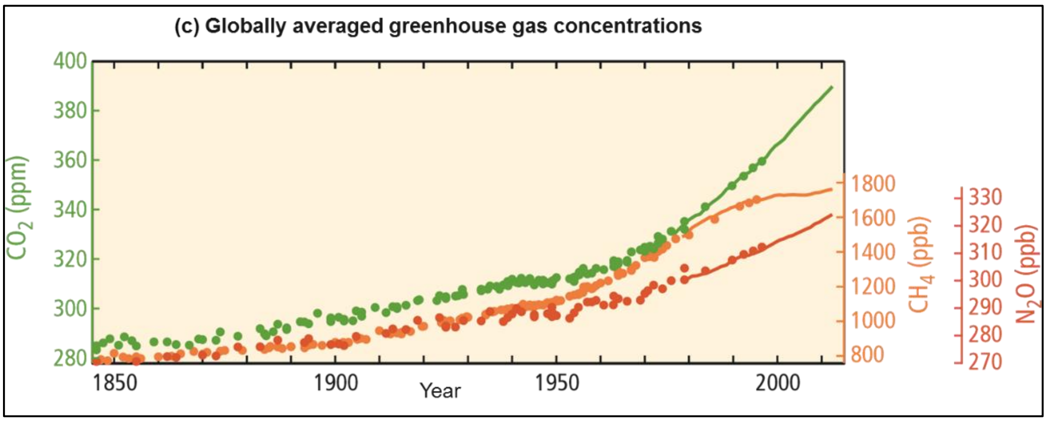


Figure 2-2- Greenhouse Gas Emission (IPCC, 2014)

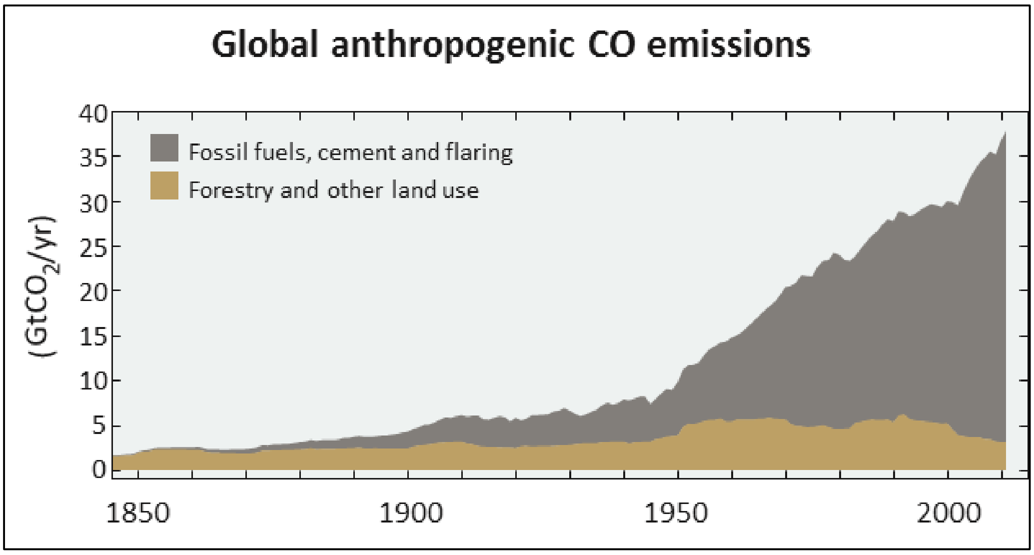


Figure 2-3- Anthropogenic CO_2 emission rate increases in a disturbing level (IPCC, 2014)

The projections of the RCPs models presented in Figure 2-4 shows that in the business as usual scenario the earth is on the path of 4°C. A really strong effort is desired to keep the warming to well below 2°C. To achieve the 2°C scenario, then a reduction of CO_2 emission to around half from the baseline is needed.

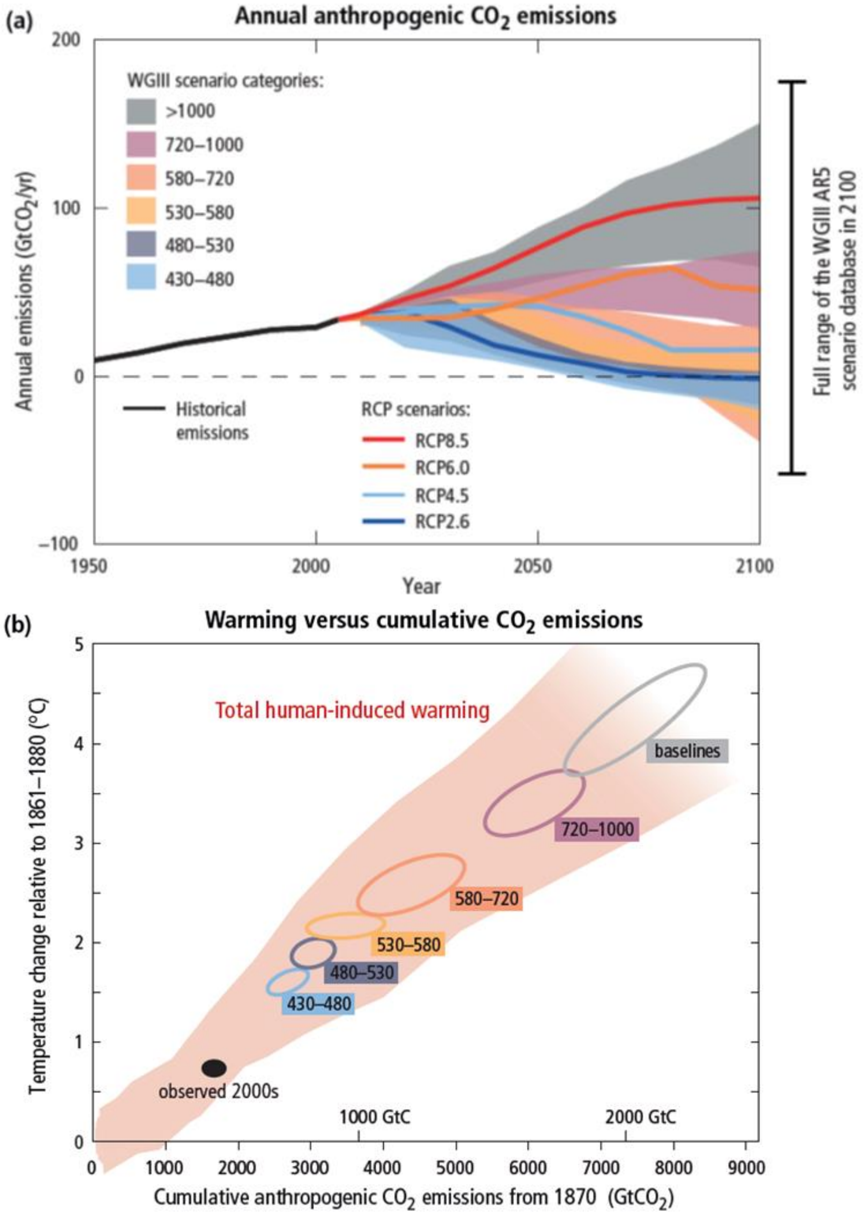


Figure 2-4-Anthropogenic CO_2 Emissions trends (a) and their effect on earth's temperature changes (b) on various RCPs to the year 2100. Source: IPCC (2014)

World Bank (2014) identified that the projected impacts of future climate change scenarios include the following:

1. Under an emissions pathway associated with a 4°C world, the occurrence of *highly unusual* and *unprecedented* heat extremes increases rapidly. In a 2°C *world, unprecedented* heat extremes would likely remain largely absent.
2. Under continued warming, precipitation changes are projected with substantial consequences for water availability.
3. Above 1.5°–2°C warming, the risks of reduced crop yields and production losses increase rapidly.
4. With increasing temperatures and changes in precipitation patterns, ecosystem shifts are projected, resulting in significantly diminishing ecosystem services
5. With rising temperature, substantially adverse effects on marine ecosystems and their productivity are expected, increases in ocean acidity, and likely reductions in available oxygen due to their combined effects
6. For the period 2081–2100 compared to the reference period 1986–2005, in a 1.5°C world sea level rise is projected to increase by 0.36 m (range of 0.20 m to 0.60 m) and by 0.58 m (range of 0.40 m to 1.01 m) in a 4°C world. The rising sea level will significantly increase the risk of storm surges and tropical cyclones. Furthermore, the sea level rise could contribute to increased salt-water intrusion in freshwater aquifers.
7. In a 4°C world, a complete deglaciation in Tropical glaciers in the Central Andes is projected. For a 2°C and a 4°C world, substantial losses of around 50 percent and up to 80 percent are projected in Central Asian glaciers.
8. Poverty reduction effort can be weakened and new groups can be pushed into poverty due to shocks and stresses related to climate change

The effort of reducing CO_2 concentration in the atmosphere has been agreed upon in COP21 Paris (2015), which was signed by 195 country leaders. The agreement was to hold the global average temperature to well below 2 °C above pre-industrial levels and to pursue efforts to limit the temperature increase to 1.5 °C above pre-industrial levels. The governments also agreed that the global emissions need to peak as soon as possible and then to undertake rapid reductions thereafter.

2.2 Carbon Capture and Storage

IPCC (2005) stated Carbon dioxide (CO_2) capture and storage (CCS) is a process consisting of the separation of CO_2 from industrial and energy-related sources, transport to a storage location and long-term isolation from the atmosphere. As can be seen in Figure 2-5, the potential storage for CO_2 includes geological storage, ocean storage, and mineral carbonation. For now, only the geological storage is widely applied, while the ocean storage and mineral carbonation is still in research phase.

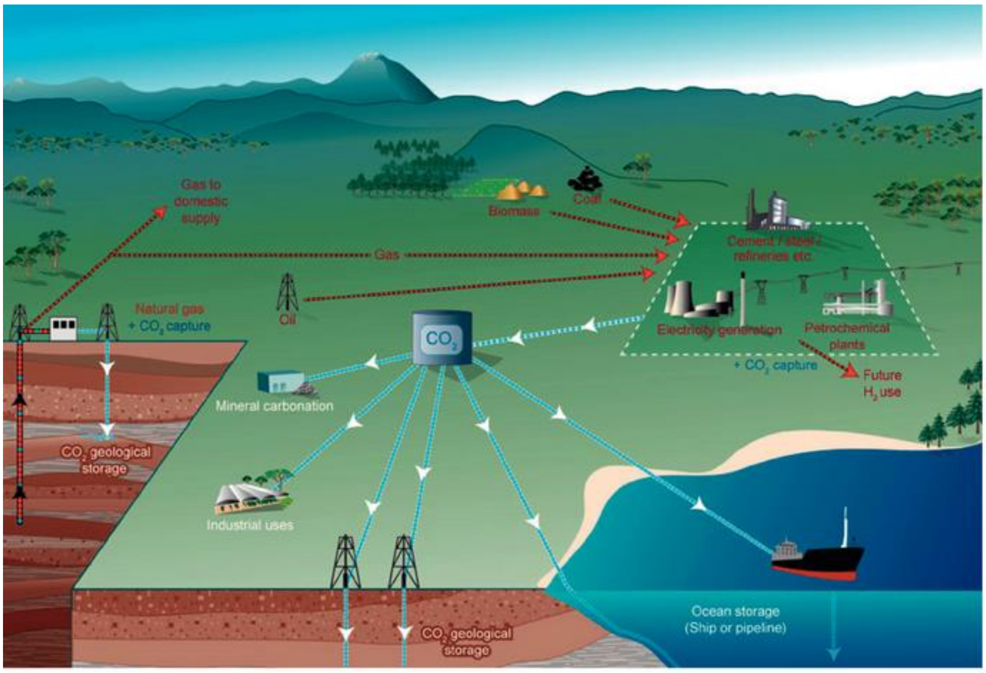


Figure 2-5- CCS systems showing the carbon sources for which CCS might be relevant, and options for the transport and storage of CO_2. Source IPCC (2005)

The importance of CCS on fighting global warming was stated in the IPCC's (2014) Fifth Assessment Report (AR5). Without CCS the cost to reach the 1.5°–2°C target will increase the mitigation cost by 138%. Also in the report of the Work Group III of the climate change mitigation IPCC (2014) the models that could achieve the 1.5°–2°C target reduced from 22-36 scenarios with CCS to only 3-6 scenarios without CCS.

The cost of electricity in order to adhere CO_2 emission limits is predicted by The Zero Emission Platform (ZEP) to be significantly higher without CCS. Without CCS, ZEP (2015) predicted that in 2050 the cost of decarbonizing European power is 20-50% higher. As in Figure 2-6, not having CCS leads to a projected cost electricity generation increase of 16 €/MWh.

Industries that are producing CO_2 are subjected to either carbon credit or CO_2 tax in some countries. In the case of USA's Carbon Dioxide Sequestration Credit, CO_2 sequestration into qualified geological storage will benefit the companies by 21.85 USD/Metric Ton for CO_2 storage and 10.92 USD/Metric ton for CO_2-EOR (IRS, 2015). In Alberta (Canada) and Norway, the CO_2 tax of 15CAD/metric ton CO_2 and 4-69USD/metric ton CO_2 are imposed respectively (World Bank, 2014). The increase of Carbon credit and CO_2 tax could be the driving force that will accelerate CCS and CO_2-EOR projects around the world.

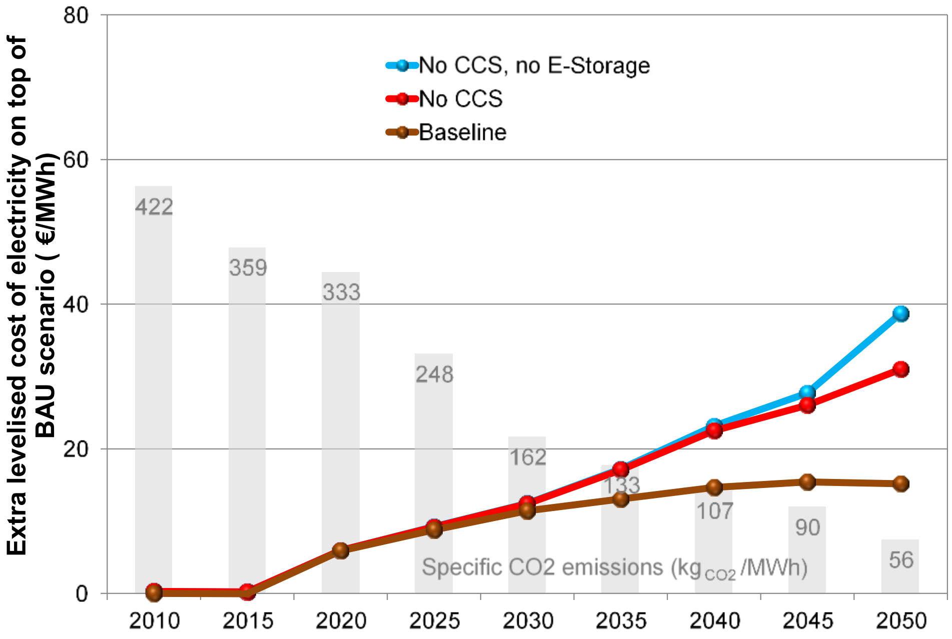


Figure 2-6- Cost of electricity will increase significantly without CCS. Source ZEP (2015)

2.2.1 CO_2 Geological Storage

The injection of CO_2 into geological storage was first done commercially by Statoil in 1996 to avoid CO_2 tax in the Sleipner Field. The CO_2 avgift (CO_2 tax) was introduced in 1991 in Norway at the rate of 210NOK/ metric ton CO_2, this tax was increased to 410NOK/ metric ton CO_2 in 2013. The Sleipner Field is a gas field with CO_2 content in the range of 4-9 percent. With the market specification of CO_2 content less than 2.5%, then the CO_2 should be separated from the produced gas. The CO_2 capture technology is using amine based process. The Captured CO_2 then injected into a saline reservoir at the rate of almost 1 million metric ton per year. Around 15.5 million metric ton of CO_2 have been injected (GCSSI, 2016). The sketch of The Sleipner project is shown in Figure 2-7.

Deep saline aquifers, depleted oil and gas fields, and also un-mineable coal are considered to be potential CO_2 geological storages. Three essential elements to consider a CO_2 geological storage projects technically feasible are as the following: Adequate capacity, safe containment, and sufficient injectivity (CO2 Capture Project, 2009). When a geological storage candidate fulfills those requirements then the CO_2 storage project can proceed.

According to the Carbon Storage Atlas (NETL, 2015), the capacity of a CO_2 storage in general is determined by the total area (A), thickness (h), porosity(Ø), CO_2 density(ρ), and the storage efficiency factor(E):

- In Oil and Natural Gas Reservoirs the efficiency factor derived from local experience or reservoir simulation. The volumetric equation calculation accounts water saturation (Sw) and formation volume factor (B) as the following:

$$G_{CO2} = A\, h_{net}\, Ø\, (1\text{-}S_w) B\, \rho\, E$$

- In Saline formations the efficiency factor for the P10, P50, and P90 percent confidence intervals are 0.51%, 2.0%, and 5.5%, respectively. The volumetric equation calculation is as follows:

$$G_{CO2} = A\, h_{gross}\, Ø\, \rho\, E$$

- In un-mineable coal, the efficiency factor for the P10, P50, and P90 percent confidence intervals are 21%, 37%, and 48%, respectively. The volumetric equation calculation accounts the fraction of adsorbed CO_2 (C_s) and CO_2 density ($r_{s,max}$) as the following:

$$G_{CO2} = A\, h_{gross}\, C_s\, r_{s,max}\, E$$

Caprocks or seals are the permeability barriers (mostly vertical but sometimes lateral) that prevent or impede migration of CO_2 from the injection site, IPCC (2005). As CO_2 injected, when it has a lower density than the surrounding fluid then due to buoyancy it will migrate upwards. When the seal is weak then the risk of CO_2 leak will increase, thus reducing the reliability of the CO_2 storage candidate.

The injectivity characteristic of a CO_2 storage is dictated by the permeability of the reservoir itself. Permeability is a measurement of the easiness of fluid flow in a porous medium. Higher permeability allows higher CO_2 injection rate, thus the CO_2 stored would be higher. However, very high permeability streaks would induce CO_2 migration along a concentrated pathways reducing the storage efficiency (CO2 Capture Project, 2009).

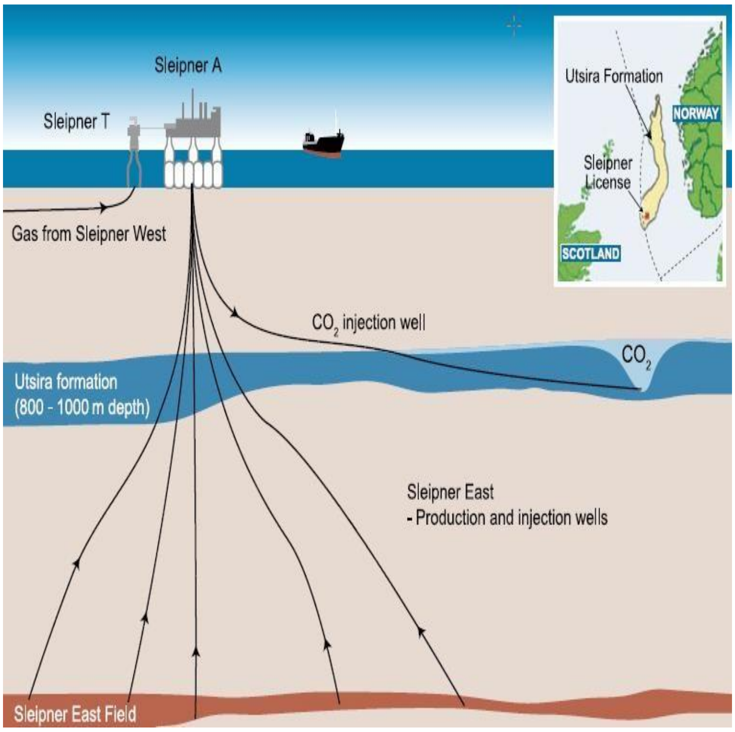


Figure 2-7- Sleipner Project, the first commercial CCS project in the world. Source: Statoil (Hagen, 2015)

2.2.2 CO_2 Geological Storage Mechanism

IPCC Special Report on Carbon Dioxide Capture and Storage (2005) explained that once CO_2 is injected into the formation, the primary flow and transport mechanisms that control the spread of CO_2 include:

- Fluid flow (migration) in response to pressure gradients created by the injection process;
- Fluid flow in response to natural hydraulic gradients;
- Buoyancy caused by the density differences between CO_2 and the formation fluids;
- Diffusion;
- Dispersion and fingering caused by formation heterogeneities and mobility contrast between CO_2 and formation fluid;
- Dissolution into the formation fluid;
- Mineralization;
- Pore space (relative permeability) trapping;
- Adsorption of CO_2 onto an organic material.

As shown in Figure 2-8, IPCC (2005) recognize 4 trapping mechanisms: Structural and Stratigraphic Trapping, Residual CO_2 Trapping, Solubility Trapping, and Mineral Trapping. The safety of CO_2 storage will improve with the order of the trapping mechanism where the structural trapping as the least secure and mineral trapping as the most secure.

Structural trapping is an impermeable caprock containing the geological storage. Stratigraphy trapping is a seal due to unconformities, sealing faults, and pinchouts. Injected CO_2 into the geological storage, as it has a lower density than its surrounding fluid will rise to the impermeable layer above and spread horizontally as the CO_2 injection continues. To prevent the seal integrity from being compromised, it is important to avoid over pressuring the injection.

Residual trapping happens as the CO_2 migrates, some of it is retained in the pore space by capillary forces. A significant amount of CO_2 may be immobilized by this trapping mechanism. Figure 2-9 shows the residual trapping of CO_2 as the CO_2 migrates. Kumar (2004) in his work shows that residual trapping is an important trapping mechanism as it can immobilize a considerable amount of CO_2.

The injected CO_2 will interact with the formation water as it shares the same pore space. From IPCC (2005) it explains that the interaction will result in the dissolution of CO_2 in formation water. The CO_2 solubility in the formation water decreases as temperature and salinity increase. Dissolution occurs rapidly, however when the formation fluid is saturated with CO_2 the rate slows down and is controlled by diffusion and convection rates. The dissolved CO_2 in the formation water exist not as gaseous phase anymore, therefore the buoyancy drive is eliminated. This process is called solubility trapping.

CO_2 mineralization is a process whereby the CO_2 that is injected into a geological formation dissolves into the formation water, reacts with the insitu minerals and ions, and precipitates as carbonate minerals (Thibeau, Nghiem, & Ohkuma, 2007). This process is called mineral trapping. Mineral trapping is a permanent form of geological storage (Gunter, Perkins, & McCann, 1993)

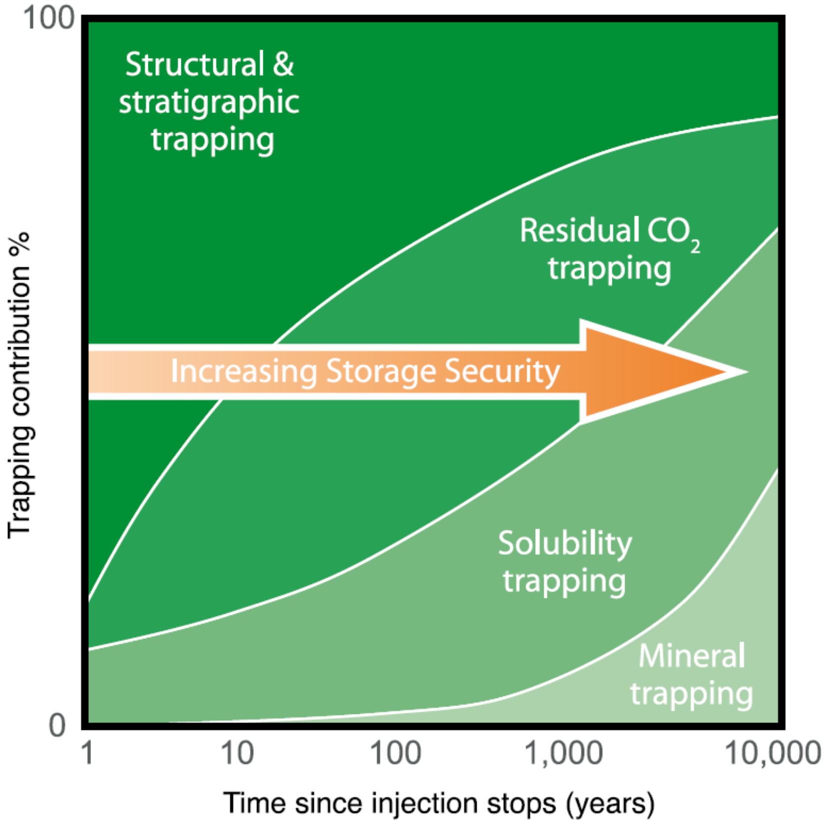


Figure 2-8- CO_2 Trapping mechanisms. Source: IPCC (2005)

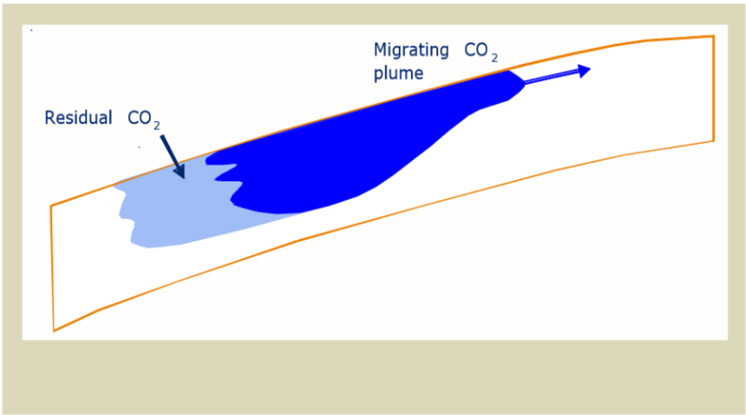


Figure 2-9- CO_2 residual trapping. Source: CO_2 Capture Project (2009)

2.2.3 CO_2 Geological Storage Optimization

Nghiem (2009) stated that an important endeavor in designing a CO_2 storage process is to speed up the storage security by accelerating solubility and residual trapping. Water (brine) injection is normally used to achieve that goal. In his work, he discovered that a water injector located above the CO_2 injector (Figure 2-10) can improve both solubility trapping and residual gas trapping.

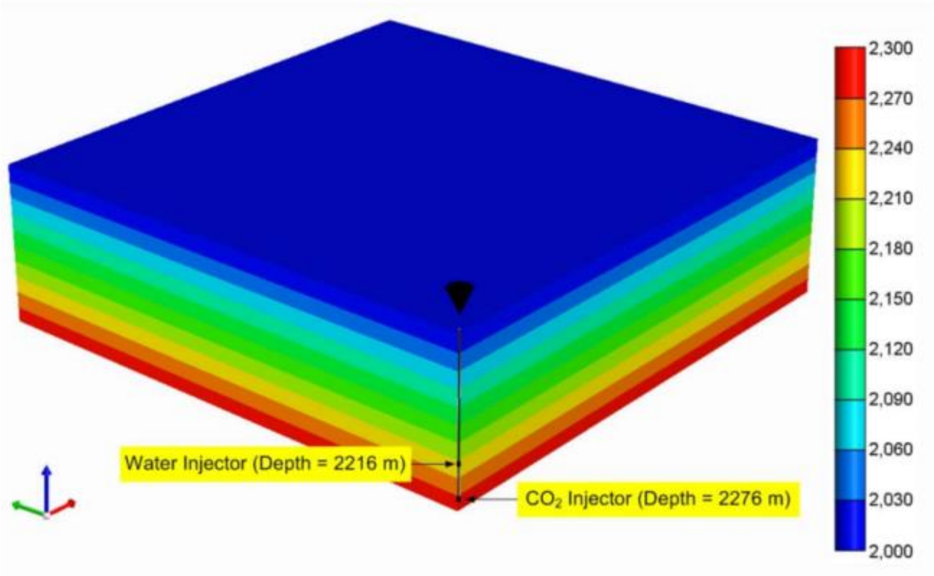


Figure 2-10- Injection strategy to improve both solubility trapping and residual trapping. Source: Nghiem et al. (2009)

Nghiem (2009) works simulated several CO_2 injection cases in low permeability cases of kh = 100md and kv =10md and also in high permeability cases of kh = 500md and kv = 50md. The success parameter was to maximize the total trapping efficiency index (TEI) of both residual trapping index (RTI, Total mass of CO_2 trapped as residual gas divided by total mass of CO_2 injected) and solubility trapping index (STI, Total mass of CO_2 trapped as soluble in brine divided by total mass of CO_2 injected). In the case of low permeability, the method of water injection above CO_2 injection was able to increase the TEI to 0.971 compared to 0.801 without water injection. In the case of high permeability, the method was not able to give a notable improvement in TEI.

An injection method of WAG to improve the performance of CO_2 storage was assessed by Juanes et al. (2006). The work concluded that alternating water injection stimulates more trapping and a significant decrease in the amount of CO_2 that accumulated at the top of the aquifer. The trapping was enhanced due to water displacing CO_2 radially away from the wells, which can be seen as a forced imbibition process. The decrease of gas saturation in the top layer can be seen in Figure 2-11.

From the works above, it can be concluded that brine injection into the CO_2 geological storage could improve the trapping which immobilizes the CO_2. The increased amount of immobile CO_2 could greatly increase the security of the storage. However, injecting water into the storage will cause an additional pressure increase which then could compromise the seal integrity (Juanes, E. J. Spiteri, Jr., & Blunt, 2006). As such, the increased pressure due to water injection and the trapping enhancement due to water injection need to be optimized to ensure a good trapping and good storage security.

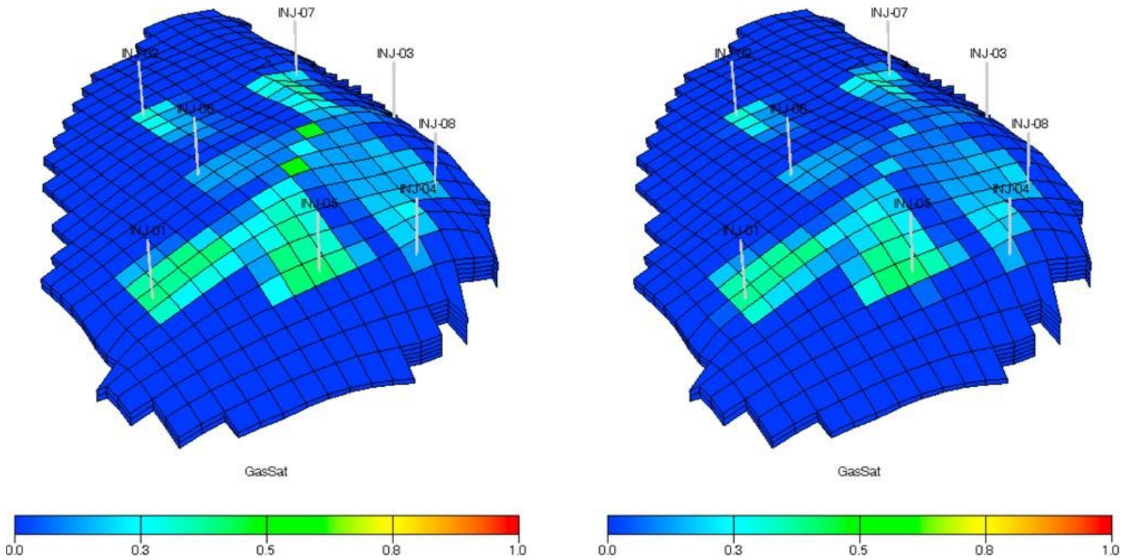


Figure 2-11- Top layer's gas saturation of without WAG (left) and with WAG (right). Source: Juanes et al. (2006)

2.3 CO_2 EOR

The utilization of CO_2 as EOR commercially started in 1972 at SACROC (Scurry Area Canyon Reef Operators Committee). The CO_2 utilized in this project was captured from a series of natural gas processing plants in the Val Verde Basin of West Texas. Before the utilization of CO_2 for EOR, the by-product CO_2 would be released into the atmosphere. (Wallace, Kuuskraa, & Advanced Resources International, 2014).

Since then, many CO_2-EOR projects has been established around the world. Figure 2-12 shows that until 2014 the trend of project count is increasing. Along with the increase of CO_2 projects, the oil production volume from CO_2-EOR is also increasing as shown in Figure 2-13. The graphs prove that CO_2-EOR has been very well recognized as a reliable and profitable way to increase oil production.

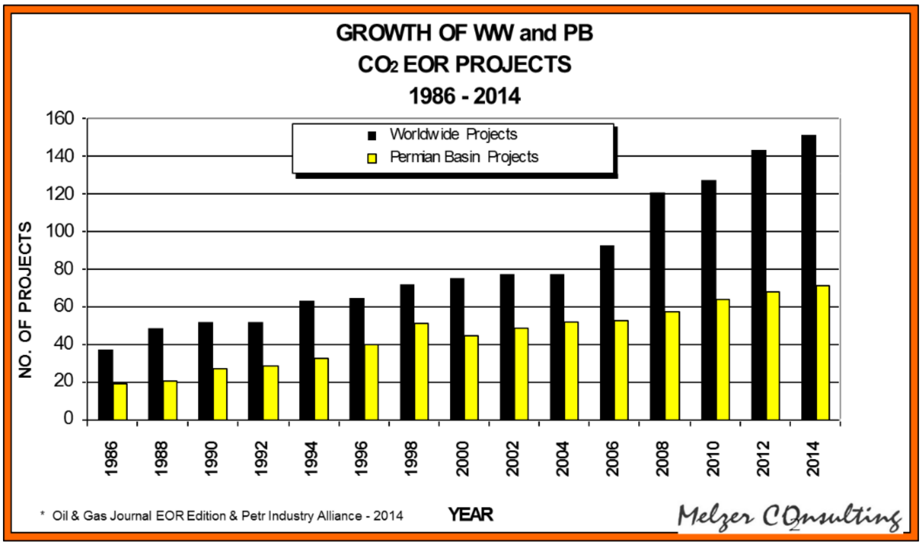


Figure 2-12- CO_2-EOR projects Worldwide, US, and in Permian Basin shows increasing trend. Source: Melzer (2015)

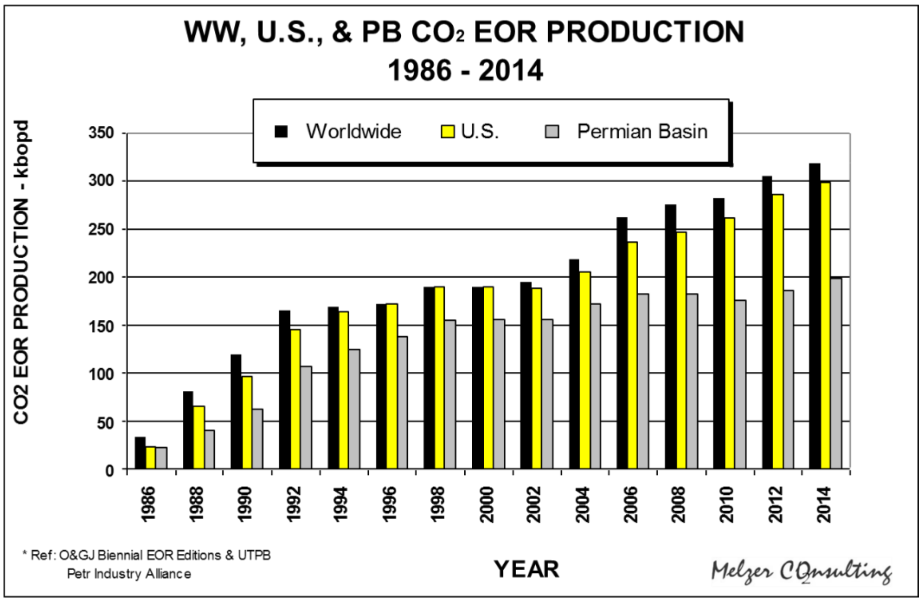


Figure 2-13- CO_2-EOR Productions Worldwide, US, and in Permian Basin shows increasing trend. Source: Melzer (2015)

In 2014 there is a drop in oil price from around 110 USD/Barrel to around 40 USD/Barrel as can be seen in Figure 2-14 . The drop is due to the supply increase much higher than the demand as shown in Figure 2-15. However, it is projected that the gap between supply and demand will narrow down and come across in 2017. As the supply and demand gap narrowed, oil price recovery has been seen in these past months.

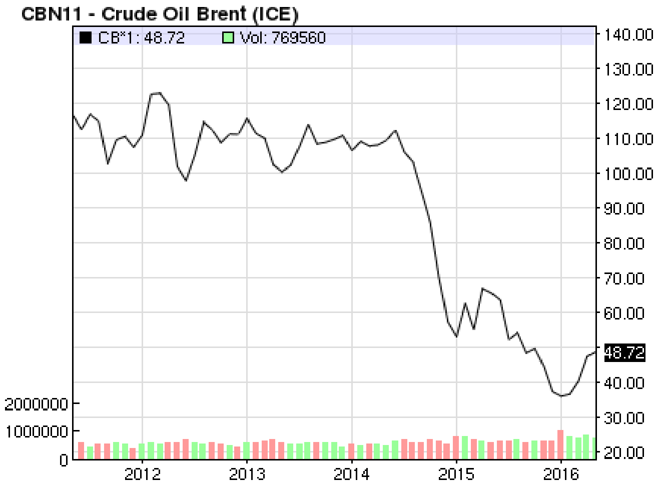


Figure 2-14- Crude Oil Brent Price from the last 5 years. Source: NASDAQ (2016)

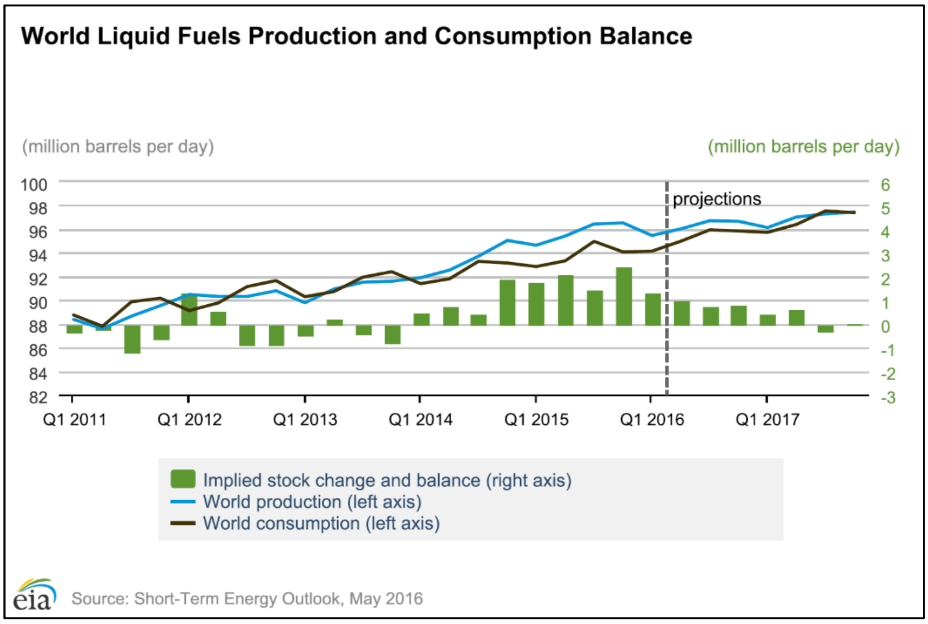


Figure 2-15- Oil Supply and Demand. Historical data from 2011-Q1 2016. From the graph it is projected that the gap will decrease and in 2017 the supply and the demand line will meet. Source: IEA (2016)

An interesting presentation by Melzer (2015) shows that during the lower oil price era from 1988-2000 with an average oil price of 18.8 USD/Barrel the CO_2 projects increase by average more than 2 projects/year as shown in Figure 2-16. By looking the graphs of CO_2-EOR project trend and the supply-demand trend, the CO_2-EOR projects' number would likely to continue increasing trend as one of the most successful EOR in the world.

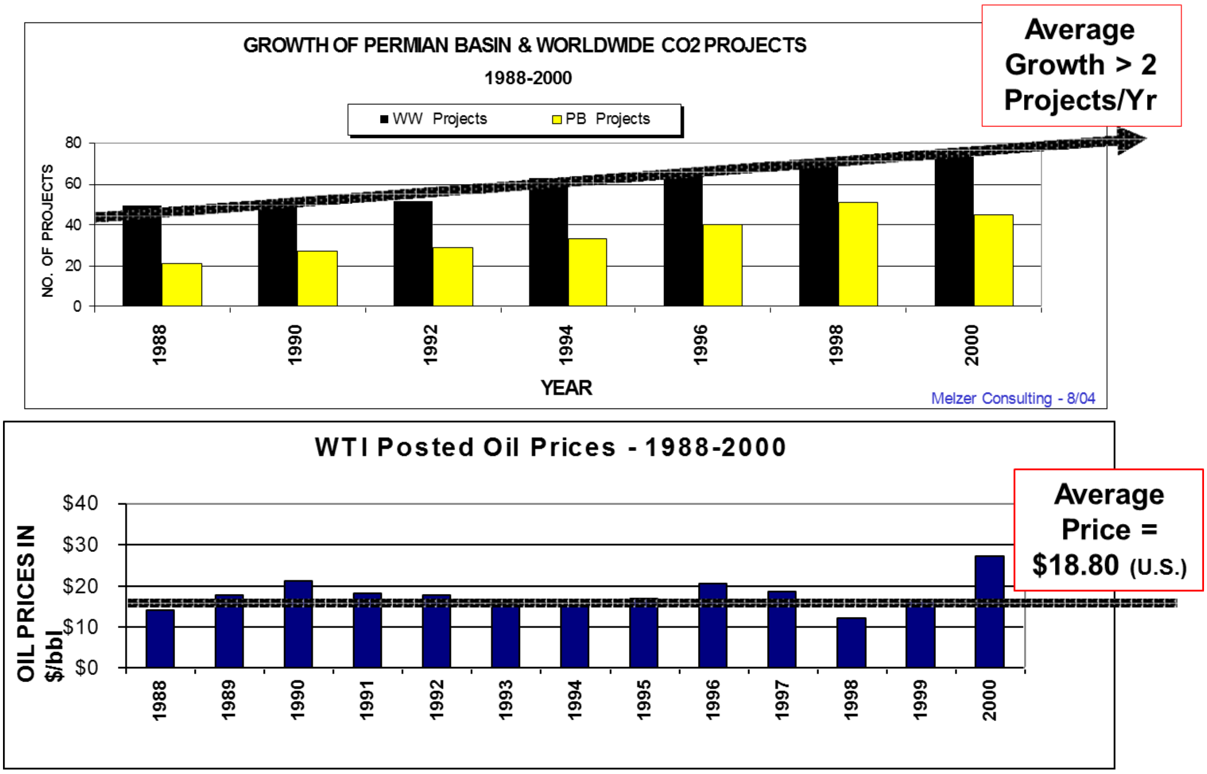


Figure 2-16- CO_2-EOR project trend is still increasing despite the lower oil price in 1998-2000. Souce: Melzer (2015)

2.3.1 CO_2-EOR Mechanisms

CO_2 performs in the following ways (Holm & Josendal, 1974):

1. It promotes swelling
2. It reduces oil viscosity
3. It increases oil density
4. It is highly soluble in water
5. It exerts an acidic effect on rock
6. It can vaporize and extract portions of crude oil
7. It is transported chromatographically through porous rock

Klins (1984) mentioned the swelling is important for two reasons: First, the swelling factor is inversely proportional to the residual oil left in the reservoir, i.e. the higher the swelling factor the higher the recovery. Second, swollen oil droplet will forces the water out of the pore spaces, creating a drainage rather than an imbibition process for water-wet system.

In the application of Darcy's Law in reservoir engineering, the rate of fluid will be inversely proportional to the viscosity of the fluid. Lower oil viscosity would be beneficial in improving oil production rate. CO_2 injection has been able to reduce crude oil viscosity by 25%-30% in the Salt Creek Fied as reported by Bargas et al (1992). The oil viscosity reduction improves oil mobility, reducing mobility ratio, thus increasing recovery.

The CO_2 injection may lead to density increase in the oil. The benefit of this is as the oil and water density become close to each other, the chances of gravity segregation will lessen (Holm & Josendal, 1974). As known, the oil is usually in lower density than water, so that there is a tendency for water under-running. With higher density in the oil then the contact between water and oil would be more effective. This would be very beneficial during WAG injection.

CO_2-water mixture is slightly acidic and reacts accordingly with the formation matrix as explained by Klins (1984) in his book. In shales, clay is stabilized by carbonic acid due to a reduction in pH. In carbonates, as the CO_2-water mixture partially dissolve the reservoir rock, the injectivity would be improved. However, the dissolution of carbonates may release unreacted fines that may plug the pore spaces. The dissolution would also produce calcium sulphate or asphaltenes that may offset the permeability increase gained previously.

Holm & Josendal (1974) recognize the ability of CO_2 to extract or vaporize hydrocarbons from a crude oil or a reservoir oil as its most important characteristic. As displayed in Figure 2-17, the CO_2 first saturates the crude oil in the front portion. Then, gas equilibrium was developed as the light ends (C_1 to C_4) are vaporized from the oil. As the CO_2 injection continues, the extraction of hydrocarbon components of approximately the C_5 to C_{30} will form a transitional zone separating the injected CO_2 from the oil in place. At the higher pressure flood, a higher concentration of hydrocarbons is present in the transition zone and a lower total residual saturation is left in the sand packs after the flood.

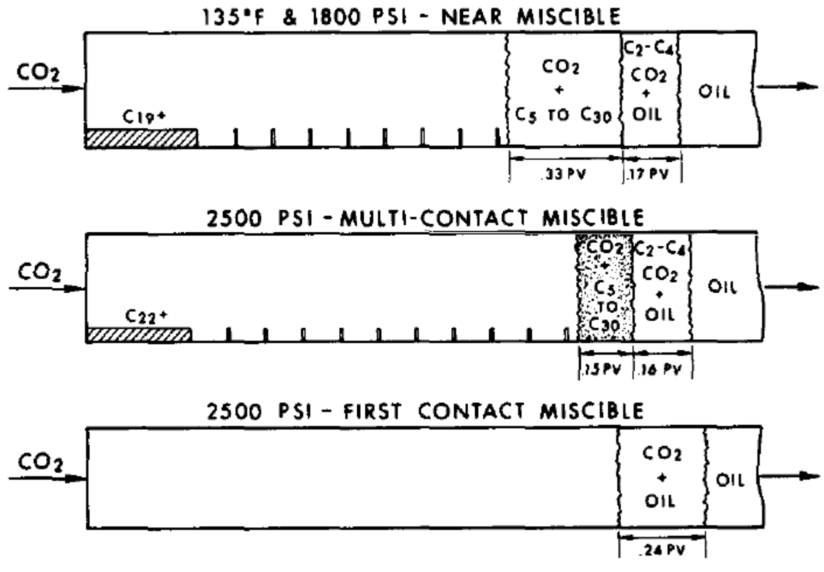


Fig. 7—Schematic of CO_2 displacement at miscible and near-miscible conditions (based on floods in long slim sand packs)—135°F.

Figure 2-17- Oil composition during CO_2 flooding as a function of pressure. Source: Holm & Josendal (1974)

The injection of CO_2 into the reservoir is either as miscible or immiscible. Whether the injection is miscible or immiscible it depend on the minimum miscibility pressure (MMP) required. When the pressure is above MMP the process is called miscible, and when below it then the process is called immiscible. MMP is defined by Holm & Josendal (1974) as the pressure where more than 80% of oil in place recovered at CO_2 breakthrough and more than 94% of oil in place is recovered ultimately.

2.3.2 Miscible CO_2-EOR

Miscibility is defined as the ability of two or more substances to form a single homogeneous phase when mixed in all proportions (Holm, 1986). As the fluids mixed, there is no more interfacial tension (IFT) exist. As the IFT equal to zero then the residual oil saturation will be reduced to zero. Miscible displacements are divided as first contact miscible (FCM) and multiple contact miscible (MCM).

FCM means that any amount of solvent (in this case CO_2) can be injected and will exist as a single phase with the crude oil in the reservoir (Holm, 1986). CO_2 does not become miscible due to FCM with most oil reservoir even at high pressure. CO_2 can develop miscibility through MCM under specific oil composition of also specific pressure and temperature condition (Parra-Ramirez, Peterson, & Deo, 2001)

Jarrell, Fox, Stein, & Webb (2002) in their book explain that in the MCM miscibility the CO_2 first condenses into the oil, making it lighter and frequently driving methane out in advance of the “oil bank”. The lighter component of the oil then vaporizes into the CO_2-rich phase, making it denser. The denser CO_2-rich phase becomes more like oil, thus become more soluble in oil. Mass transfer between the two will continue until the resulting two mixtures become indistinguishable. At that point, the IFT will be zero resulting in a single hydrocarbon phase.

In practice, Miscible CO_2-EOR will never reach zero residual oil. Reasons that affect oil recovery was summarized by Tzimas et al. (2005) as the following:

- CO_2 need a finite distance to flow through the reservoir before full miscibility is achieved.
- Higher mobility of CO_2 compared to oil resulted in unstable flow due (viscous fingering)
- The unstable flow above resulted in early breakthrough of CO_2 (Figure 2-18)
- Significant density differences between CO_2 and oil or from high permeability reservoir rock, which leads to phase segregation resulting in gravity effect
- CO_2 will need to mobilize water in the reservoir left behind after water flooding

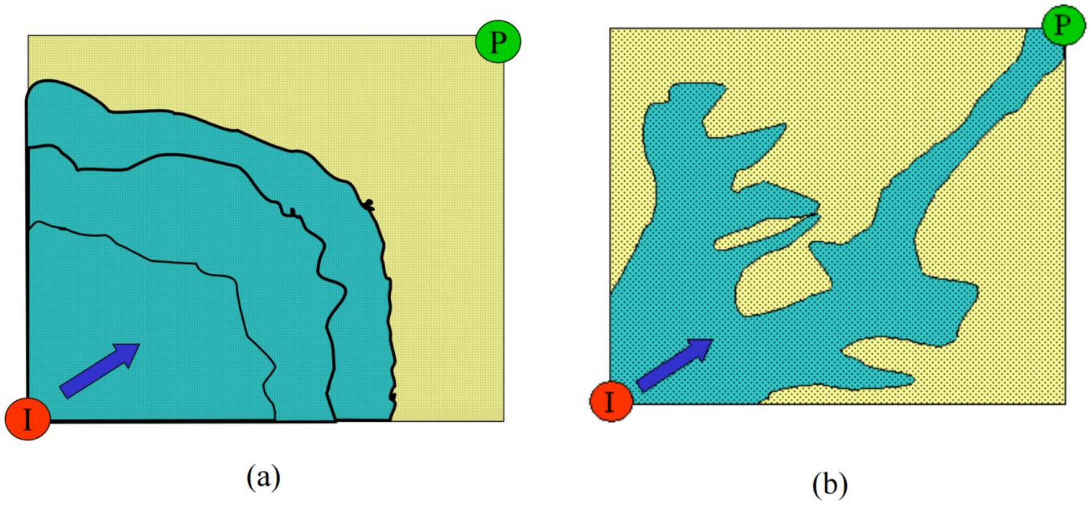


Figure 2-18- (a) represent a stable front between the injected CO_2 and the oil, while (b) represent unstable front (viscous fingering) resulting in earlier breakthrough and limited contact area between CO_2 and oil. Source: Tzimas et al. (2005)

2.3.3 Immiscible CO_2-EOR

Immiscible CO_2-EOR occurs when the system's pressure does not exceed the MMP. The reasons might be due to technical or economic constraints. Example causes as the following: MMP above fracturing pressure, insufficient water injectivity for pre-EOR treatment, and lower pressure ratings of the current producing facilities.

The following factors are identified as important immiscible CO_2 process based on Bargas et al (1992):

1. **Oil Swelling**. Oil mobility will improve by increasing oil relative permeability
2. **Viscosity reduction**. Oil viscosity reduction will lower the mobility ratio which will improve oil recovery.
3. **Trapped gas saturation**. Additional oil forced out of the water-wet pore spaces due to CO_2 trapped by chase water.
4. **Sweep improvement**. The CO_2 trapped will reduce the water relative permeability, then resulting in water to seek different flow channels that are less likely to have been contacted with CO_2.
5. **CO_2 solubility in water**. Using CO_2-saturated water, as the water sweeps to areas not contacted by CO_2, the CO_2 in the water will absorb into the undersaturated oil to mobilize more oil.

2.3.4 CO_2 EOR Injection Methods

Based on Klins (1984) there are 5 CO_2-EOR injection methods: Continuous CO_2 injection, carbonated waterflooding, CO_2 slug and water, CO_2 WAG, and simultaneous water injection on top CO_2 injection. Jarrel et al (2002) stated additional methods as the following: Tapered WAG and WAG chased with gas.

Based on the explanation of Klins (1984) and Jarrel et al (2002) each injection method are described as the following:

1. **Continuous CO_2 injection**. In this injection, a predetermined CO_2 slug is injected without any interference from any other injection fluid. This method usually is implemented directly after primary depletion in gravity drainage reservoir or a non-waterfloodable reservoir.
2. **Carbonated Waterflooding**. CO_2 diffuses out of the injected CO_2-saturated water when in contact with oil. This diffusion is slower compared to the injection of pure CO_2 slug.
3. **CO_2 slug and water**. In this process, waterflooding commence after the predetermined CO_2 slug was injected. This approach is usually implemented in a more homogeneous reservoir.
4. **CO_2 WAG**. This method is a variation of the previous process. Instead of big slug size of CO_2 injection then waterflooded, Small slugs of CO_2 gas and water injection is injected by turns. The benefit of this method is the lower CO_2 mobility. This injection is very effective in highly stratified heterogeneous reservoirs. Areal and vertical sweeps efficiencies are improved in by using this method.
5. **Simultaneous water injection into the top layer and CO_2 injection into the bottom layer**. Water is injected on top of the pay zone, while CO_2 is injected on the bottom. The water would be segregated downward and the CO_2 would rise.
6. **Tapered WAG**. In this process, the water injection lengths will increase as the cycle continues. Sometimes chase water of waterflooding follows the tapered WAG. The objective of this method is to reduce the CO_2 utilization factor.
7. **WAG chased with gas**. The WAG process will be followed by the injection of less expensive gas. The main purpose of this method is to reduce the amount of CO_2 required, while maintaining miscible displacement in the trailing edge of the CO_2 slug. Sometimes, the gas was chosen due to the inability to use water injection in the reservoir.

2.4 Storing CO_2 in CO_2-EOR Project

CO_2-EOR is a closed system, it means that the produced CO_2 is recycled to be injected back to the reservoir with no intentional release to the atmosphere. Since not all of the injected CO_2 is produced, then the field operators need to purchase additional CO_2 to meet their injection target. In the report written by Dilmore (2010), after the CO_2-EOR project ended, the total CO_2 purchased minus losses would be amounted as sequestered in the reservoir. The losses included all of the CO_2 released into the atmosphere through the period of active injection and the additional 100 years after the end of the injecting activity.

In the report from IEA (2014), it suggested increasing the amount of CO_2 used to increase the oil recovered. The injection of more CO_2 may lead to higher oil recovery and also higher CO_2 utilization factor. The report shows three CO_2-EOR scenario as the following: Conventional EOR^+ with incremental oil recovery of 6.5% OOIP and CO_2 utilization factor of 0.3 tCO_2/bbl, Advanced EOR^+ with incremental oil recovery of 13% OOIP and CO_2 utilization factor of 0.6 tCO_2/bbl, and lastly Maximum Storage EOR^+ with incremental oil recovery of 13% OOIP and CO_2 utilization factor of 0.9 tCO_2/bbl.

As global warming becomes an increasingly significant issue, the urge to decrease the CO_2 concentration in the atmosphere increases as well. The economical push for CO_2 capture may in the form of CO_2 tax such as in Norway, CO_2 credit such as in the USA or in any other form in the future will become increasingly common in the world. This opens a big possibility that the amount of anthropogenic CO_2 available for CO_2-EOR will increase. The increase of availability may lead to the decrease of CO_2 price, or even maybe shifting CO_2 commodity economic status from operating cost into additional revenue. In the report from IEA (2014), the prediction of CO_2 price will go down depending on the climate change mitigation target. The possibility of CO_2 storage to actually add revenue to the field operator is predicted under the 2° scenario.

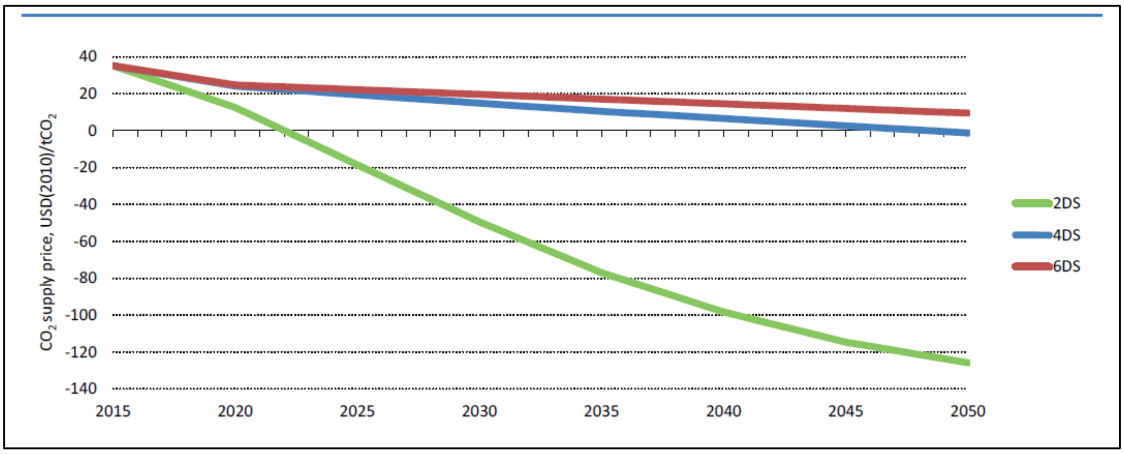


Figure 2-19- Average CO2 supply prices. The scenarios is based on the assumption of the climate change mitigation effort target, which is 6°, 4°, or 2°. Source: IEA (2014)

3. Model Description

Investigating co-optimization of CO_2 EOR and storage was done using CMG GEM simulator. The template of "gmthr010.dat" from CMG GEM was used as the base for this study. The fluid model and the grid model principal inputs is described in the following subchapters.

3.1 Fluid Modelling

The oil model was made by using N_2, CO_2, and C_1-C_{30+} components with composition as shown in Table 3-1. The oil density is 842.9 kg/m^3 (36.2 API) with bubble point pressure of 2300 kPa. The water density is 997.2 kg/m^3. Water salinity is kept constant at 0.1 mol NaCl/kg H_2O. Chemical reactions selected is shown in Table 3-2. In the aqueous reaction, the dissolution of CO_2 into the water will form H^+ and HCO_3^-. The formation of H^+ will lower the pH of the formation water and may resulted in mineral dissolution.

The solubility of CO_2 in brine is described as the following reversible reaction:

$$\mathbf{CO_2\ (g) \leftrightarrow CO_2\ (aq)}$$

CO_2(g) represent CO_2 in the gas phase, while CO_2(aq) represent CO_2 in the aqueous phase. In this model, as explained in the manual, CMG GEM modeled the solubility of CO_2 in brine by using Harvey correlation for Henry's constant. This option is activated by using the keyword *HENRY-CORR-CO_2. The calculation used are as the following:

$$\ln H_i^s = \ln p_{H_2O}^s + A(T_{r,H_2O})^{-1} + B\left(1 - T_{r,H_2O}\right)^{0.355}(T_{r,H_2O})^{-1} + C\left[\exp\left(1 - T_{r,H_2O}\right)\right](T_{r,H_2O})^{-1}$$

H_i^s	=	Henry's constant for component i at sat pressure of H_2O (Mpa)
$p_{H_2O}^s$	=	Saturation Pressure for H_2O in Mpa at T(K)
T_{c,H_2O}	=	Critical Temp of H_2O (K)
T_{r,H_2O}	=	T/ T_{c,H_2O}, Reduced temp of H_2O

For CO_2, the A= -9.4234, B=4.0087, C= 10.3199

Henry's law constant at p and T is then calculated as the following:

$$\ln H_i = \ln H_i^s + \frac{1}{R\,T}\int_{P_{H_2O}^s}^{*p} \overline{v_i}\,dP$$

The mineral trapping reaction selected is known as the calcium pathway, it is based on the work of Thibeau et al. (2007). The mineral reaction in their work consist of the following:

- The mineral Anorthite: A non-carbonate, calcium-rich minerals, in which the dissolution is to provide calcium to the formation water.
- Kaolinite as the secondary minerals, in addition to calcite, that would precipitate using the ions resulting from Anorthite dissolution and Calcite precipitation.

As explained in their work, the dissolution of Anorthite and a possible calcium precipitation with HCO_3- into calcite, will lead to the precipitation of Kaolinite. The equation of Anorthite dissolution, Kaolinite precipitation, combined with calcite dissolution and the CO_2 speciation reaction, can be recombined into:

$$\textbf{Anorthite} + \mathbf{H_2O} + \mathbf{CO_2}\ \textbf{(aq)} \leftrightarrow \textbf{Calcite} + \textbf{Kaolinite}$$

Table 3-1- Oil composition

Component	**Composition mole fraction**
N_2-C_1	5.4962694E-02
CO_2	3.4124997E-03
C_2-C_3	9.7715090E-02
IC_4-NC_5	1.2760579E-01
C_6-C_9	2.9929397E-01
C_{10}-C_{19}	2.8854097E-01
C_{20}-C_{29}	9.4715490E-02
C_{30A+}	1.9379321E-02
C_{30B+}	1.4374176E-02

Table 3-2- Selected chemical reactions

Aqueous reaction	**Mineral reaction**
$(OH^-) + (H^+) = H_2O$	Calcite + $(H^+) = (Ca^{2+}) + (HCO_3^-)$
$CO_2(aq) + H_2O = (H^+) + (HCO_3^-)$	Kaolinite + 6 (H^+) = 5 H_2O + 2 (Al^{3+}) + 2 $SiO_2(aq)$
$(CO_3^{2-}) + (H^+) = (HCO_3^{-)}$	Anorthite + 8 (H^+) = 4 H_2O + (Ca^{2+}) + 2 (Al^{3+}) + 2 $SiO_2(aq)$

Table 3-3- Formation water's ions concentrations

Ions	**Initial concentration**
$\mathbf{H^+}$	1.000000E-07
$\mathbf{Ca^{2+}}$	9.118492E-05
$\mathbf{Al^{3+}}$	2.317806E-11
$\mathbf{SiO_2(aq)}$	2.345433E-08
$\mathbf{OH^-}$	5.456322E-07
$\mathbf{HCO_3^-}$	2.489299E-02
$\mathbf{CO_3^{2-}}$	1.170273E-05

3.2 Grid Modelling

This model is represented as a quarter pattern, with the first 6 layers as the oil bearing zone and the last 2 layers as the water bearing zone. The first 6 vertical blocks represent the oil bearing zone of So 0.79 and Sw 0.21. The bottom 2 vertical blocks represent water bearing zone of Sw 0.999. One injector in the corner block and one producer in the opposite corner both (Figure 3-1) were perforated in the 1^{st} layer to the 6^{th} layer. In this model Land's hysteresis was applied using sgr_{max} 0.4. The primary inputs for the grid modelling input are shown in Table 3-4. The relative permeability curves are shown in Figure 3-2.

Table 3-4- Grid modelling primary inputs

Grid Property	**Value**
Grid	9, 9, 8
length i	9 x 100m
length j	9 x 100m
length k	6x 5m, 1x50m, 1x100m
Porosity	0.28
Permeability horizontal	200 md
Permeability vertical	2 md
Reservoir Temperature	59^0C
Mineral Fraction of Calcite	0.0088
Mineral Fraction of Kaolinite	0.0176
Mineral Fraction of Anorthite	0.0088

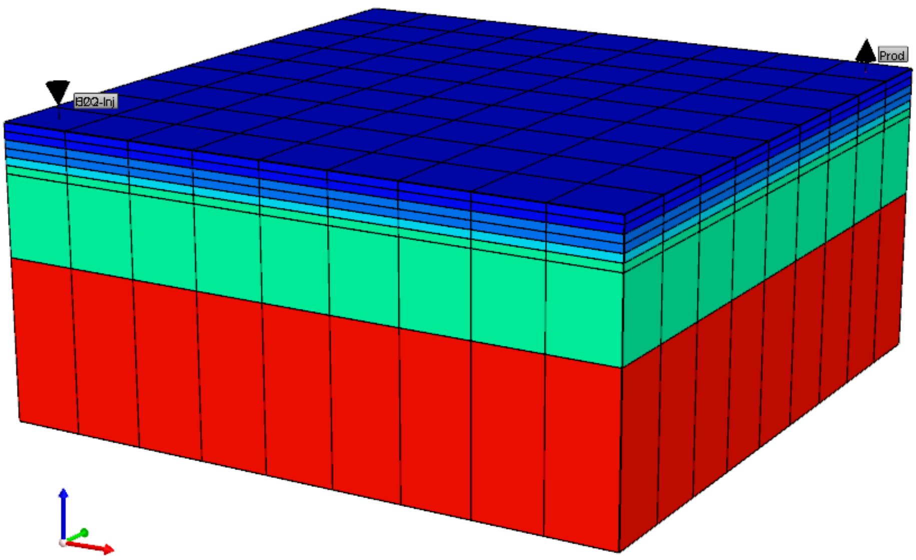


Figure 3-1- Grid model visualization

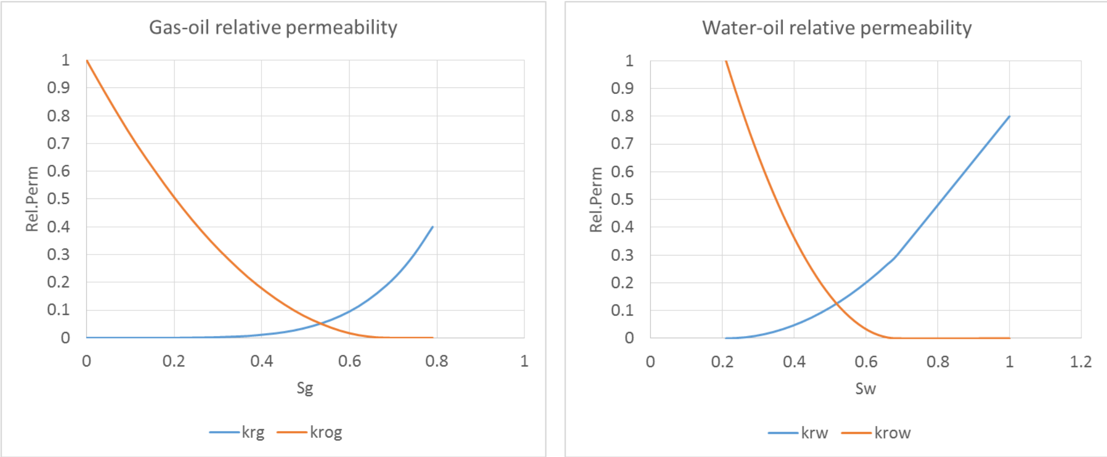


Figure 3-2-Kr curves of gas-oil and water-oil

Table 3-5 shows four injection approaches: CO_2-Only, WAG, Conwater, and Interwater. A schematic of the injection approaches is shown in Figure 3-3.

Table 3-5- Injection approaches

Injection	**Sensitivity**
CO_2	-
WAG	WAG ratio
Continuous water injection over continuous CO_2 injection (Conwater)	Water injection rate
Intermittent water injection over continuous CO_2 injection (Interwater)	Water injection rate and injection interval

Water injection into the top layer and CO_2 injection into the bottom layers was to enhance CO_2-EOR. This was published by Klins (1984). Nghiem et al (2009) stated that water injection on top of CO_2 injector improves CO_2 trapping in saline aquifer. Sobers (2012) analyzed the advantages of water injection over CO_2 injection in improving oil recovery and CO_2 trapping. However, in this project we introduced the concept of intermittent water injection over CO_2 injector. To our knowledge this has never been investigated.

The injector and producer constraints applied in this model can be seen in Table 3-6. The constraint of the maximum gas production in this simulation is set to be the same as the gas injection rate which is 250M Sm^3/day. The reason is that if the gas production rate becomes equal to the gas injection rate, then no point of continuing production since there will be no CO_2 stored at this point. When the producer constraint is reached the producer will be shut-in, while the CO_2 injector will continue injecting CO_2 until it reached the maximum allowable pressure of 20,000 kPa. In this project, the focus will be on the period when the producer is active.

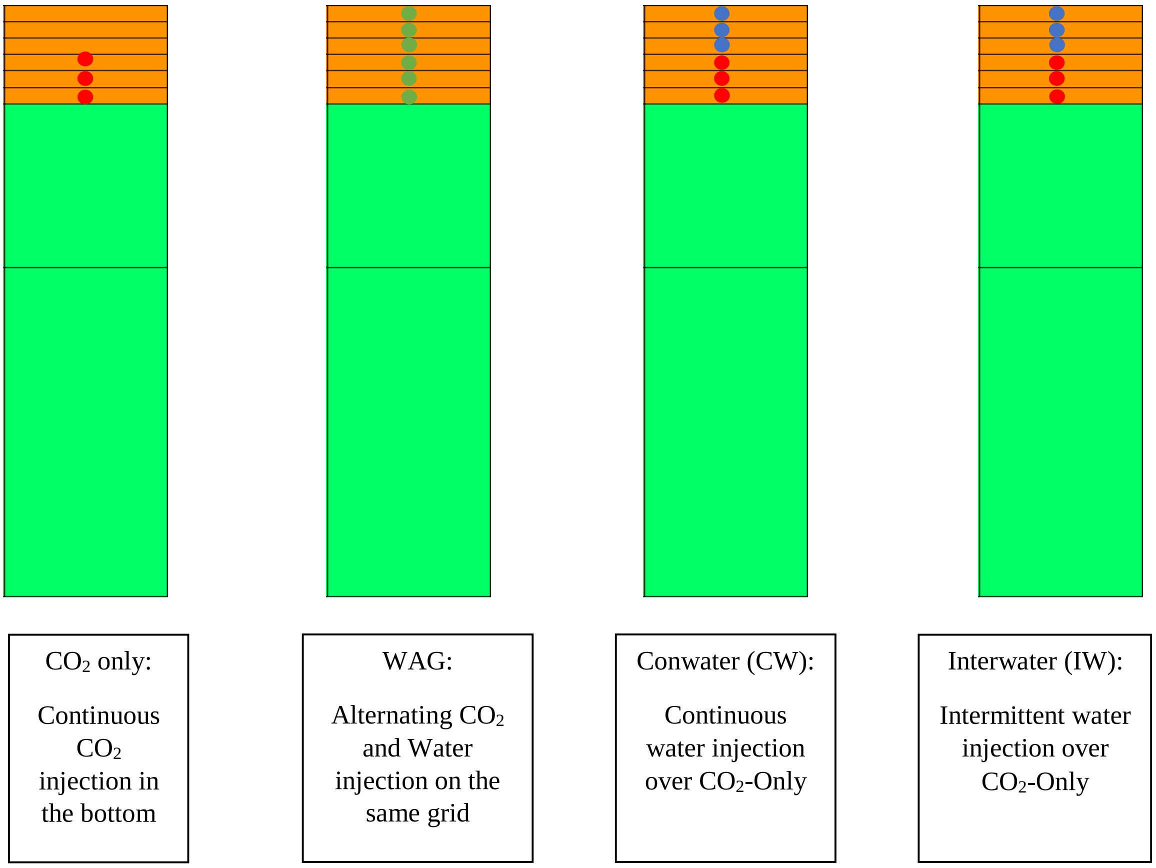


Figure 3-3- The applied injection schemes. Red is for continuous CO_2 injection, Blue is for water injection, and Green is for alternating of CO_2-water injection

Table 3-6- CO_2 injector, water Injector, and producer constraints

Constraint	**Value**
CO_2 Injector	
Maximum gas Injection	250,000 Sm^3/day
Minimum gas Injection	1000 Sm^3/day
Maximum BHP	20,000 kPa
Water Injector	
Maximum water injection	Varied
Maximum BHP	20,000 kPa
Producer	
Minimum BHP	1500 kPa
Maximum Oil Production (Prior to EOR)	250 Sm^3/day
Minimum Oil Production	10 Sm^3/day
Maximum Gas Production	250,000 Sm^3/day

4. RESULTS AND DISCUSSION

The simulation of a quarter pattern was done from year 2000 until year 2050. From year 2000 to 2005 is the natural production period, i.e. no injection. From year 2005 until 2015, water injection of 500 Sm^3/day commence for pressure maintenance. From 2015 until 2050, CO_2-EOR started. The oil recovery comparison of the maximized water injection and CO_2-EOR need to be done.

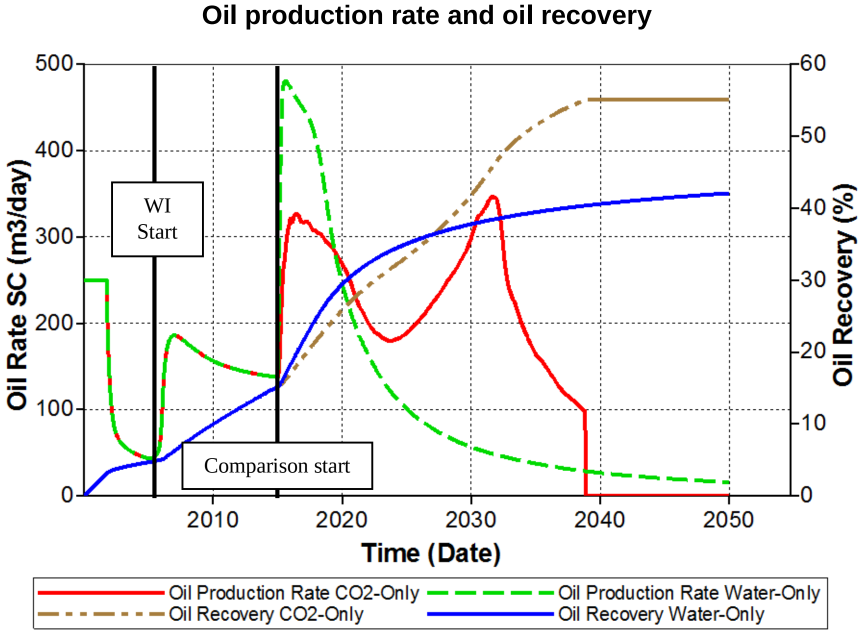


Figure 4-1- Oil production rate and oil recovery comparison of CO_2-Only and maximum water injection rate.

From Figure 4-1, it can be seen that without water injection in 2005 the oil production will decline steeply. After the water injection of 500 Sm^3/day started in 2005, the oil production increased from 46 Sm^3/day to 185 Sm^3/day and then decline moderately. In 2015 the two cases differ: The CO_2-Only case injected CO_2 gas at the rate of 250M Sm^3/day and the Water-Only case injected water at the rate allowed by the maximum allowable bottom hole pressure constraint.

The initial oil production rate increase in the Water-Only case is 342 Sm^3/day, which is much higher compared to the 187 Sm^3/day increase in the CO_2-Only case. The larger initial oil production increase may be explained based on the higher reservoir pressure due to the higher injected fluid rate (Figure 4-2). However, the oil production rate declines much steeper in the water injection case than the CO_2-Only case. This condition resulted in the lower oil recovery from the water injection case (42.1%) compared to the CO_2-Only case (55.1%). In the year 2038, the reservoir pressure started to hike in the CO_2-Only case because the CO_2 injection continues after the production shut-in as stated earlier.

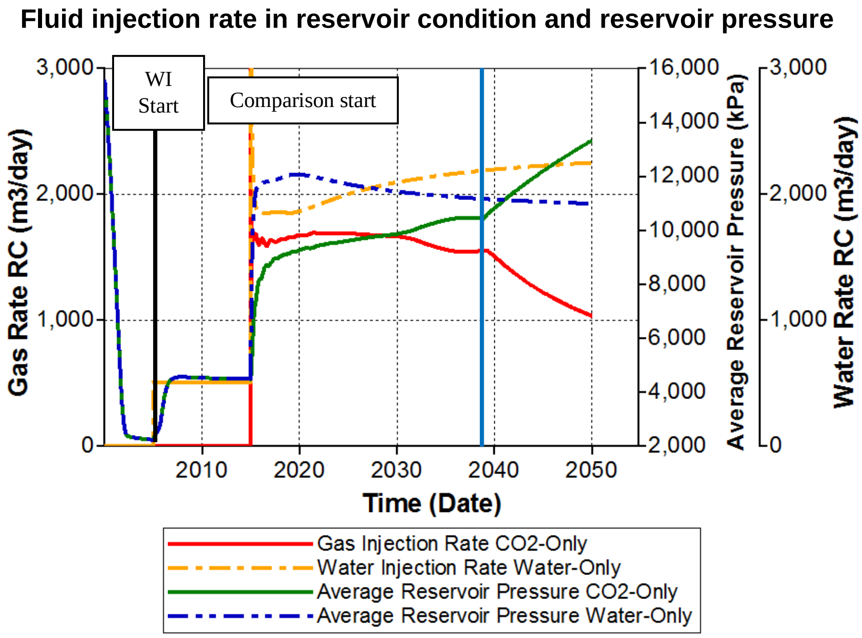


Figure 4-2- Fluid injection rate in reservoir condition (RC) and reservoir pressure. The Water-Only case injected fluid in higher rate than the CO_2-Only case, resulted in higher reservoir pressure. The CO_2 injection continues after the CO_2-Only production shut-in (blue vertical line), this resulted in the pressure hike.

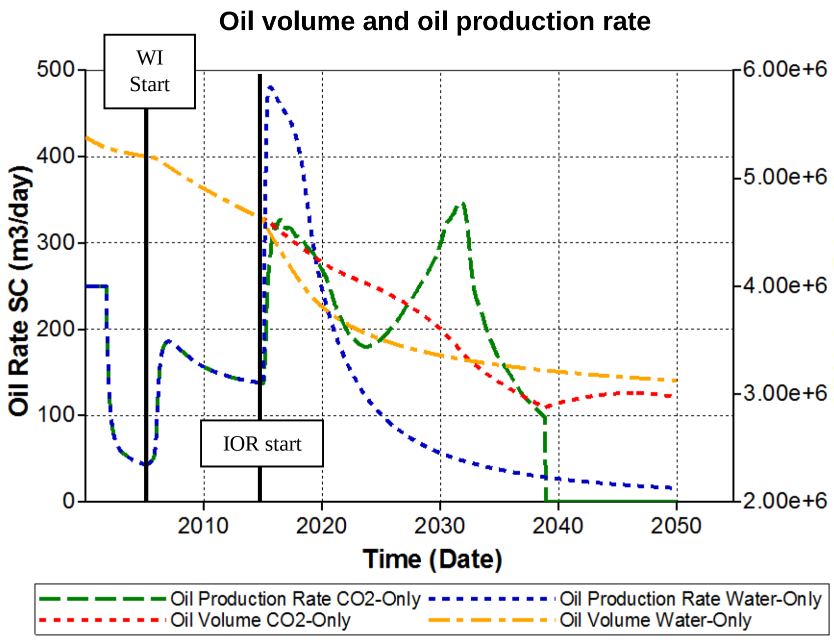


Figure 4-3- CO_2-EOR resulted in oil swell as can be seen in the change of oil volume decline trend in 2015. The swelling may contributed to the increase in oil production rate.

One of the benefits of CO_2-EOR is oil swelling. As the oil swell, the oil saturation increases, which resulted in higher oil mobility. In Figure 4-3 the correlation between the changes in oil volume decline trend with the oil production rate can be observed. Another benefit of CO_2-EOR recorded was the reduction in oil viscosity from 2.7 cp to 1.9 cp. This decrease in viscosity could also contributed to the increase in oil production rate.

In October 2038, the CO_2-Only production shut-in due to the gas production constraint. The approaches described in the previous chapter will be implemented to reduce the gas production.

4.1 Comparison of WAG, Interwater (IW) and Conwater (CW)

The investigation started with CO_2 injection rate of 250M Sm^3/day and water injection rate of 500 Sm^3/day. Summary of the injection schemes are shown in Table 4-1. WAG, CW, and IW were shown to prolong the oil production compared to the CO_2-Only case. As shown in Figure 4-4 the oil recovery is ranked as follow: WAG500-12months (≈56.6%), CO_2-Only (≈55.1%), IW500 (≈54.6%), WAG500-1month (≈53.7%), and CW500 (≈49.8%).

Table 4-1- Injection scheme of WAG, CW, and IW cases

Injection approaches	CO_2 injection rates (Sm^3)	Water injection rates after 2015 (Sm^3/day)	Water injection intervals	CO_2 injection intervals
CO_2-Only	250E+03	0	0	Continuous
WAG	250E+03	500	12 months	12 months
WAG	250E+03	500	1 month	1 month
CW	250E+03	500	Continuous	Continuous
IW	250E+03	500	1 year	Continuous

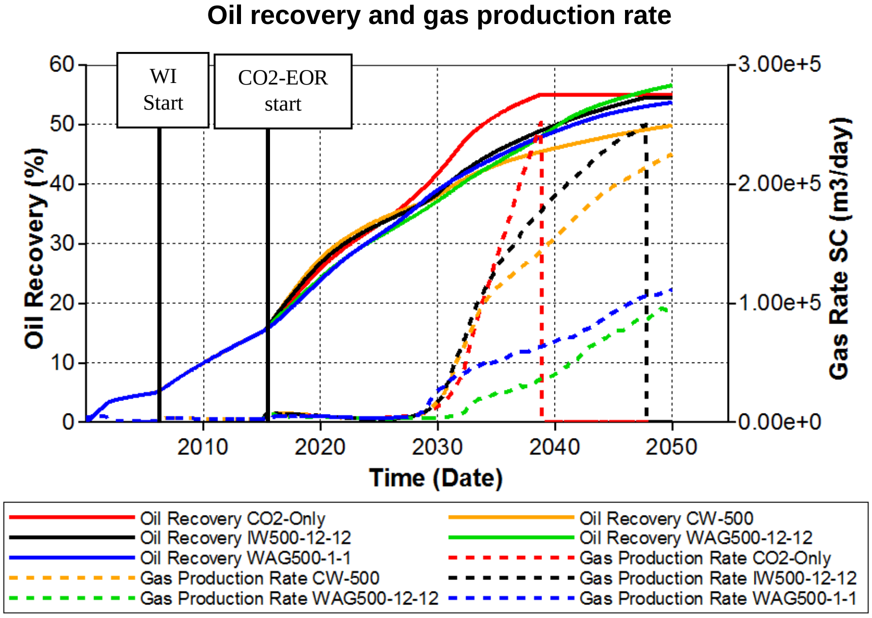


Figure 4-4 -Oil recovery and gas production chart. WAG, CW, and IW cases produced lower gas production rate than for CO_2-Only case.

Table 4-2 summarizes the injected amount and the stored amount of CO_2 before the termination of the production for each individual case (CO_2-only, WAG, CW and IW). The CO_2 stored is the cumulative produced CO_2 subtracted from the cumulative injected CO_2, during active CO_2-EOR period (from 2015 until the termination of the production). The CO_2 injected and CO_2 stored in Table 4-2 show that the application of IW and CW increased the CO_2 stored. It was shown, in this work, that 18% was the highest increase of CO_2 stored, which was achieved by the CW500 case. The WAG cases showed less CO_2 stored, due to lower injected amount CO_2 compared to the CO_2-Only case. Therefore, it was decided in this work to continue with the optimization of CO_2-EOR and storage by CW and IW

Table 4-2- Amount of CO_2 injected and stored for CO_2-Only, CW, IW, and WAG

Case	Production shut-in date	CO_2 injected before production shut-in (kg)	CO_2 stored (kg)	CO_2 stored increase compared to the CO_2-Only case (%)
CO_2-Only	11/27/2038	4.07E+09	3.41E+09	-
CW500	Never	5.97E+09	4.01E+09	18%
IW500-12-12	10/21/2047	5.59E+09	3.69E+09	8%
WAG500_12-12	Never	3.07E+09	2.51E+09	-26%
WAG500_1-1	Never	3.01E+09	2.12E+09	-38%

4.2 CW and IW

To better understand the impact of IW and CW approaches in co-optimizing the oil recovery and CO_2 storage during CO_2-EOR, a set of simulation cases as displayed in Table 4-3 was completed. The water injection rate displayed in Figure 4-5 shows that the IW approach was always been able to meet the water injection rate target, while for the CW approach the highest water injection rate of 1000 Sm^3/day was not always been able to meet its target.

Table 4-3- Variation of water injection rate and injection length of CW and IW cases

Injection approaches	CO_2 injection rates (Sm^3)	Water injection rates after 2015 (Sm^3)	Water injection intervals	CO_2 injection intervals
CO_2-Only	250E+03	0	0	Continuous
CW	250E+03	250, 500, and 1000	Continuous	Continuous
IW	250E+03	250, 500, and 1000	1 year	Continuous

Oil recovery and gas production rate in Figure 4-6 show that increasing the water injection rate and water injection length resulted in lower gas production. The case of IW250-12-12 and CW250 resulted in production termination in 2042, where the rate of 250 Sm^3/day was not enough to mitigate the gas production rate. In the case of IW500-12-12, the production was terminated in 2047, but for the case of CW500 the gas production rate was reduced until the end of simulation. One may conclude that water injection rate and water injection length are important parameters to control the gas production rate, hence the CO_2 stored.

Figure 4-7 shows that the decline rate of oil production was very steep in the CO_2-Only case, compared to the IW and CW cases. In both IW and CW cases, it was shown that the higher water injection rate and injection intervals resulted in higher oil production rate in the early EOR stage. This may be explained based on the pressure increase due to the increase of the injected fluid. However, oil production rates from the mid-stage EOR (2020) until the end of simulation were higher for the lower water injection rate and injection intervals. The oil production rate is found to be related to the water-oil mobility ratio which will be explained later.

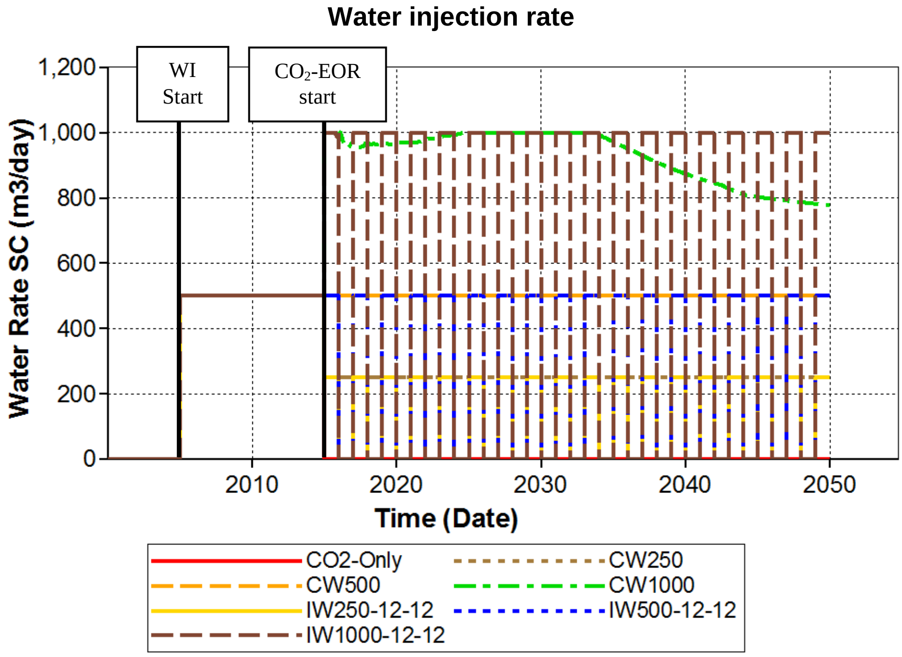


Figure 4-5- Water injection actual rates for CW and IW cases. Only the water injection rate of CW1000 that was not always meeting its target.

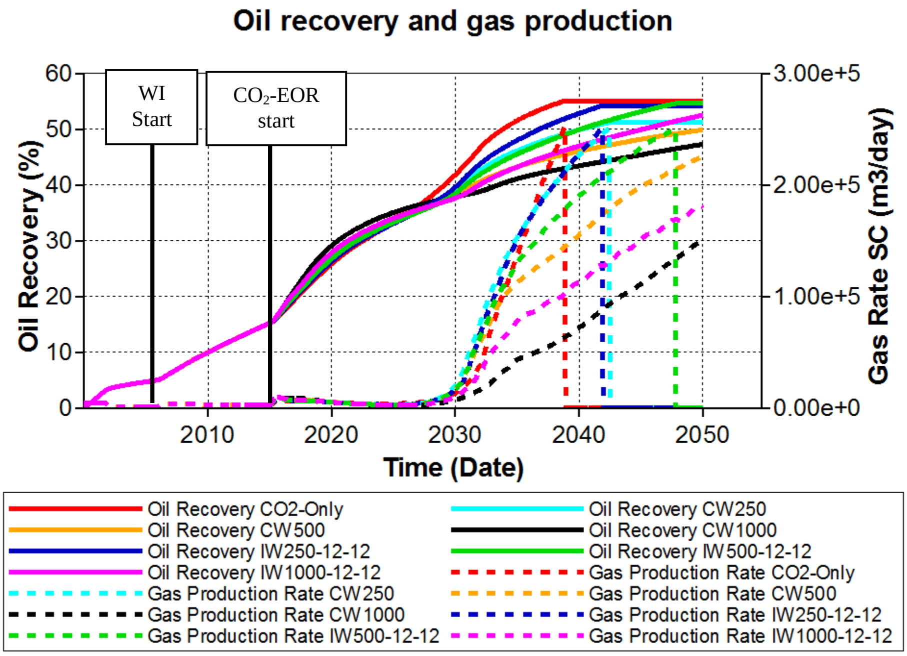


Figure 4-6 - Oil recovery and gas production rate for various CW and IW cases. CW250, IW250, and IW500-12-12 did not hold the gas production below the constraint until the end of simulation.

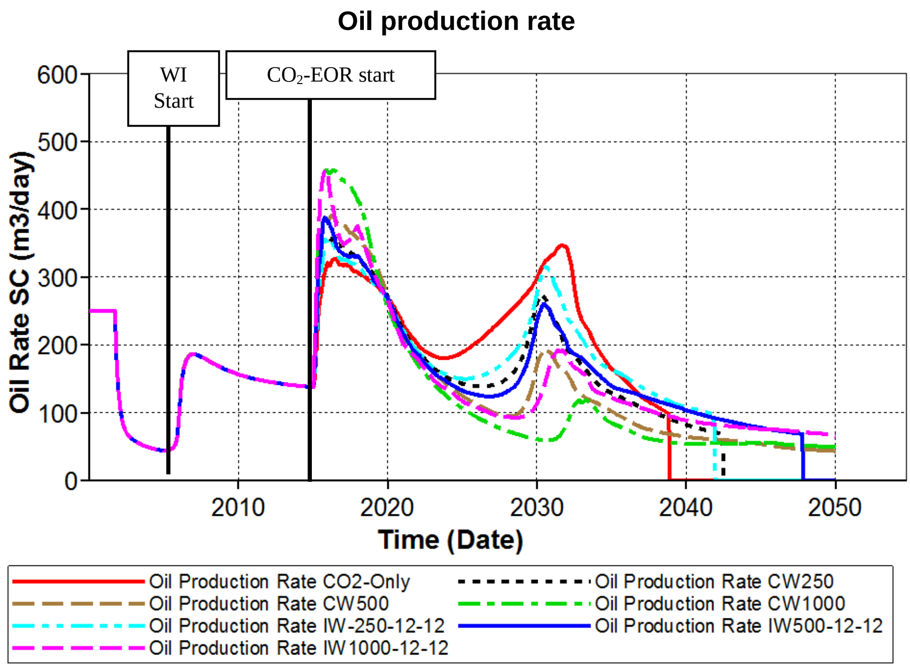


Figure 4-7- Oil rate of CO_2-Only, CW, and IW cases. CW250, IW250, and IW500-12-12 production shut-in due to gas production constraint. The oil production decline in the CO_2-Only case is very steep compared to the CW and IW cases.

For assessment of the different cases, CO_2 utilization factor (UF) was used. It is defined as the amount of CO_2 stored in the reservoir divided by the amount of incremental oil produced. In other words, when the CO_2 utilization factor increases, the oil recovery decreases as demonstrated in Table 4-4. CW1000 has the highest UF of about 19.04 tCO_2/Sm^3 oil which reduces the oil recovery by about 7.8 % OOIP, while increasing the CO_2 stored by 46%. On the other hand, IW1000-12-12 having a lower UF of about 8.7 tCO_2/Sm^3 oil increased the CO_2 stored to about 34% while the oil recovery was reduced by about 2.25% OOIP. In the case of IW1000-12-12 the performance was much better than CW500 which reduced the oil recovery by 5.17% OOIP while only increasing the CO_2 stored by merely 18%. From the above it seems that the IW to be the best approach for further consideration in this work.

Table 4-4- Sensitivity study of the stored amount of CO_2, oil recovery, and CO_2 UF by IW and CW

Case	CO_2 stored increase compared to the CO_2-Only case (%)	Oil recovery increase compared to the CO_2-Only Case (% OOIP)	CO_2 Utilization Factor (tCO_2/Sm^3 oil)
CO_2-Only	-	-	5.22
CW250	-0.7%	-3.87	7.39
CW500	18%	-5.17	10.20
CW1000	46%	-7.78	19.04
IW250-12-12	0.4%	-0.87	5.61
IW500-12-12	8%	-0.46	5.84
IW1000-12-12	34%	-2.55	8.67

4.2.1 CW and IW mechanisms for oil recovery and reduced gas production

Investigation was done to understand the reason for lower oil recovery by CW cases. Block 8,8,2 (Figure 4-8) was selected because it represents the near producer upper layer that would most likely be affected by the CW and IW approaches.

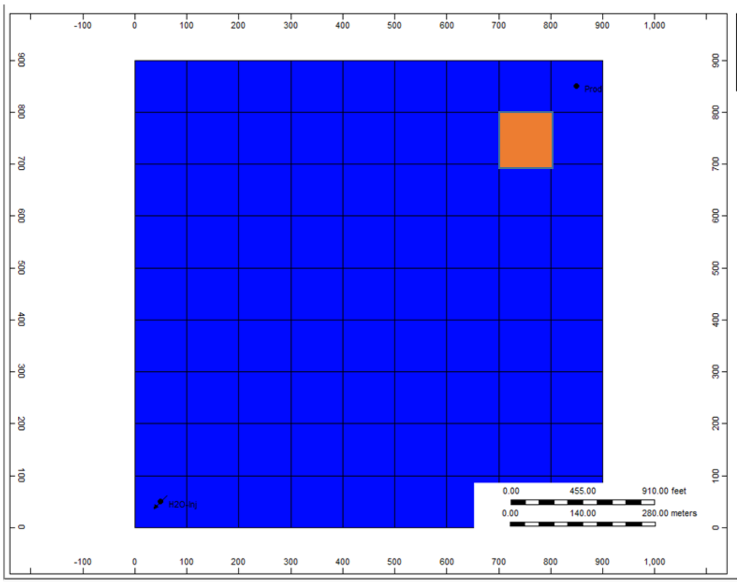


Figure 4-8- Investigated block 8,8,2. This block is selected because it is located at the upper layer and near the producer, this block would be most likely to represent the effect of water injection over the CO_2 injector.

Oil viscosity curves are shown in Figure 4-9. CO_2 was taken as a reference to the other two cases (CW and IW). The reduction of the oil viscosity was similar in all cases, which was from about 2.7 cp to about 1.9 cp, except that in the case of CO_2 only, the viscosity reduction started earlier

The gas-oil mobility ratios are displayed in Figure 4-10. It is shown that the water injection reduces the gas mobility ratios. In the case of CO_2-Only, the high gas-oil mobility ratio led to less efficient oil production as shown in the steep oil production decline as the gas-oil mobility ratios increases. This high gas-oil mobility ratios were lowered in the cases of IW500-12-12 and CW500. Since CW500 has lower gas-oil mobility ratio, the gas production was lower than in the IW500-12-12 case.

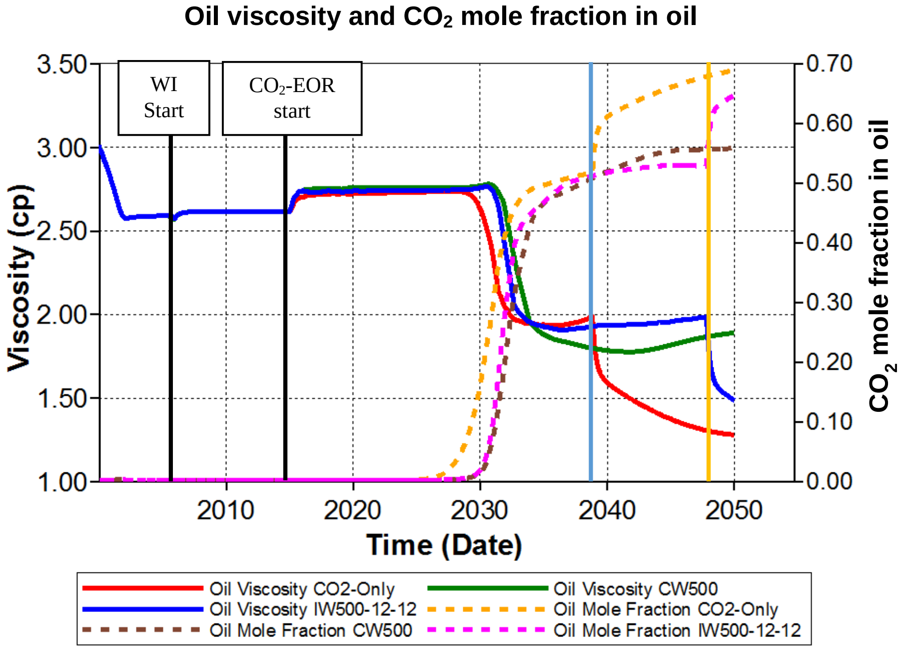


Figure 4-9- Oil Viscosity of CO_2-Only, CW500, and IW500-12-12 at near wellbore grid (8,8,2). The vertical lines represent the production shut-in times: blue is for the CO_2-Only case and yellow is for the IW500-12-12 case. Viscosity reduction occurred first in the case of CO_2 -Only case.

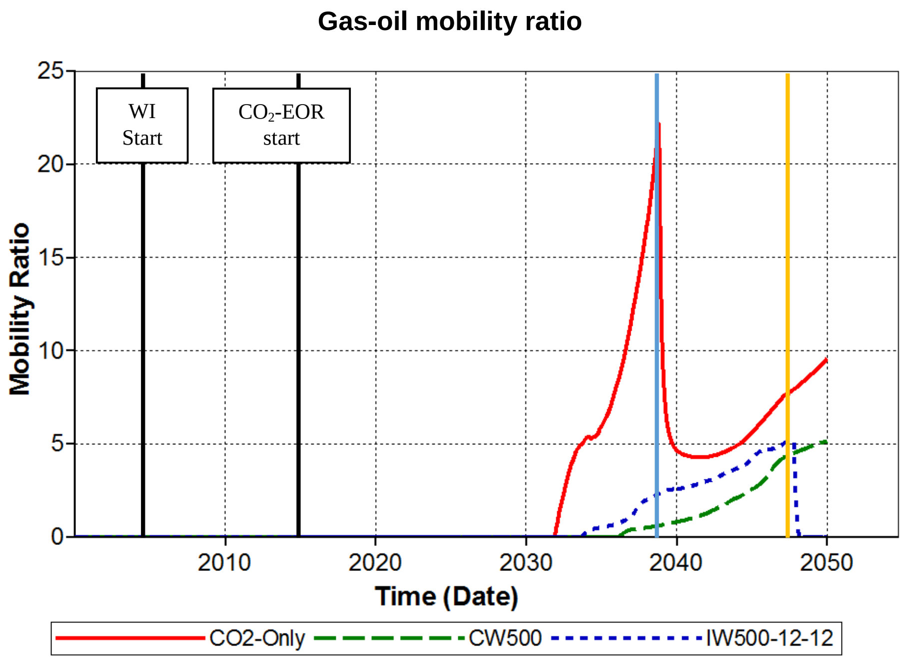


Figure 4-10- Gas-oil mobility ratio for CO_2-Only, CW500, and IW500-12-12 at near wellbore (8,8,2). The vertical lines represent the production shut-in time: blue for the CO_2-Only case and yellow for the IW500-12-12 case. The gas-oil mobility ratios were reduced in the IW and CW cases.

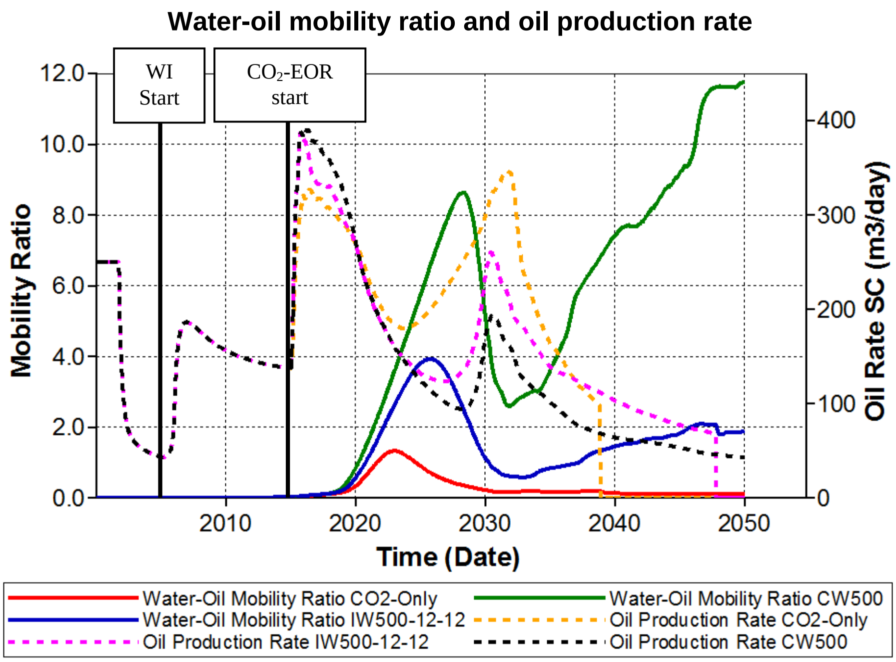


Figure 4-11- Water-oil mobility ratio of CO_2-Only, CW500, and IW500-12-12 at near wellbore (8,8,2). The oil production ranking is the inverse of the water-oil mobility ratio.

Figure 4-11 shows that the IW case has lower water-oil mobility ratio than in the CW case. The water-oil mobility ratios were around 2.0 and 11.4 at the end for IW500-12-12 and CW500, respectively. In other words, IW is more effective in displacing oil than CW.

Figure 4-12 shows that applying the CW500 and IW500-12-12 resulted in better solubility trapping and residual gas trapping than the CO_2-Only case. More solubility trapping was expected due to the additional water injection providing more solution sights for the CO_2 to dissolve. The increase in residual trapping in the IW500 and CW500 cases is perhaps due to the decrease of the gas mobility.

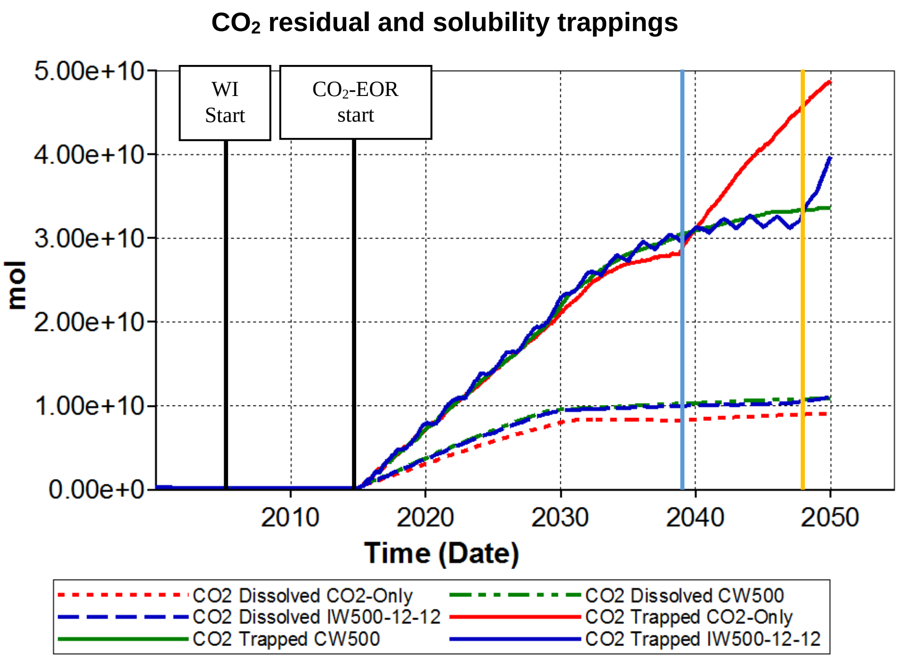


Figure 4-12- CO_2 residual and solubility trappings by CO_2-Only, CW500, and IW500-12-12. The vertical lines represent the production shut-in time: blue is for the CO_2-Only case and yellow is for the IW500-12-12 case. The residual and solubility trapping were improved in the CW and IW cases.

4.3 Interwater Sensitivity Analysis

A sensitivity analysis was done with the Interwater approach by varying the water injection rate and the interval period. The water injection rate of 500 Sm^3/day, 750 Sm^3/day, and 1000 Sm^3/day were selected, since below 500 Sm^3/day was not enough to improve the CO_2 stored. The water injection intervals ranged from 3 months, 6 months, 9 months, and 12 months, with shut-in interval of 12 months, were investigated.

It can be observed that in the lowest interval which is the 3-12 cases (3 months water injection-12 months no water injection), the oil recovery trend is better than using the other intervals as shown in Figure 4-13, Figure 4-14, and Figure 4-15. However, the 3-12 interval is not enough to mitigate the gas production so that the production shut-in before the end of simulation.

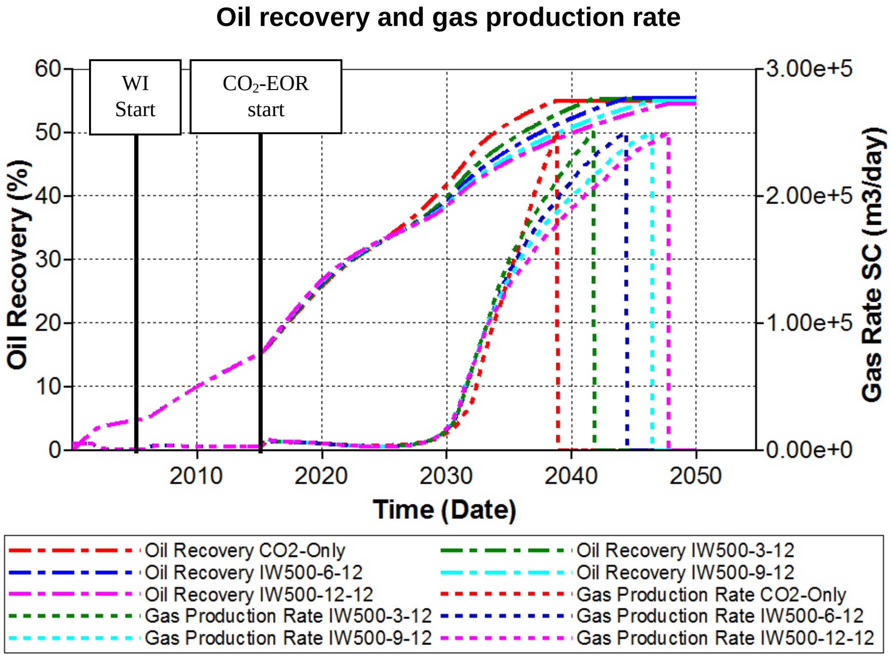


Figure 4-13- Oil recovery and gas production rate of IW500 with various injection intervals.

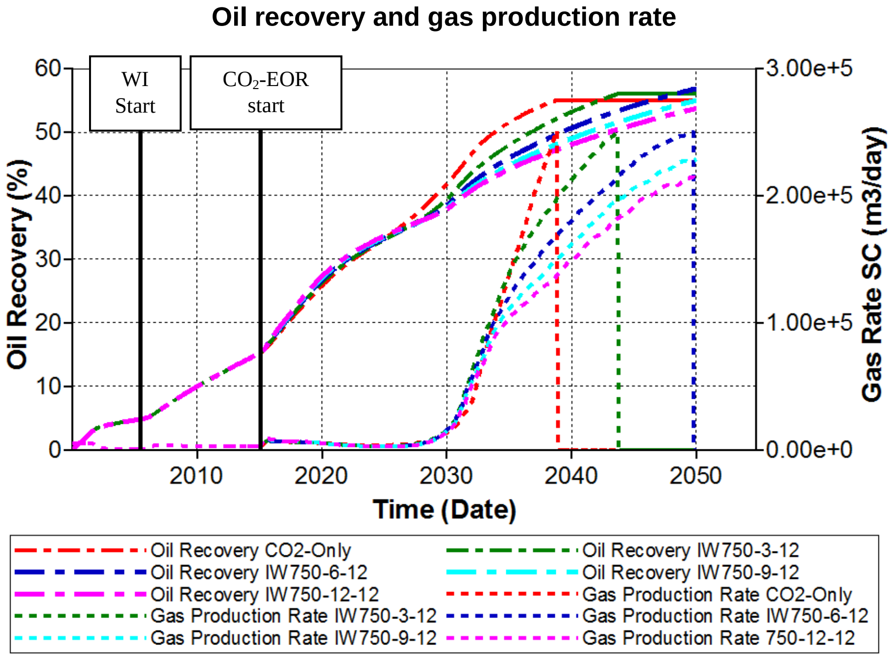


Figure 4-14- Oil recovery and gas production rate of IW750 with various injection intervals.

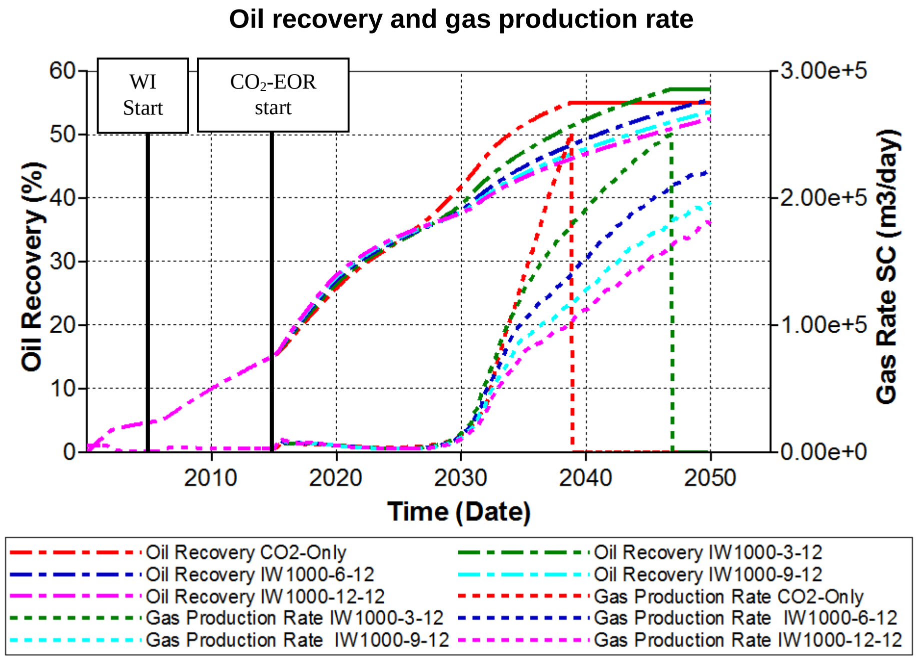


Figure 4-15- Oil recovery and gas production rate of IW1000 with various injection intervals.

All of the IW cases have successfully increased the CO_2 stored compared to the CO_2-Only case as shown in Table 4-5. The case of IW500-3-12, showed the lowest increase of the CO_2 stored (1%), while IW1000-12-12 showed the largest increase of the CO_2 stored (34%). One may conclude here that for the same water injection rate, the CO_2 stored increases with the water injection intervals.

There are 6 cases in which the oil recovery is higher than the CO_2-Only case. The highest oil recovery increase was 2.11% OOIP obtained by IW1000-3-12 case. Also in this case, the CO_2 stored increase was 9%. The CO_2 UF was about 4.84 tCO_2/ Sm^3 oil, which is lower than the CO_2-Only case (5.22 tCO_2/Sm^3 oil). It is interesting to see that there are total of 5 IW cases that have a lower CO_2 UF than the CO_2-Only method. We may conclude here that IW approach could be economically and practically attractive.

Table 4-5- Sensitivity study of the stored amount of CO_2, increased oil recovery, and CO_2 UF with application of IW

Case	CO_2 stored increase compared to the CO_2-Only case (%)	Oil recovery increase compared to the CO_2-Only case (% OOIP)	CO_2 Utilization Factor (tCO_2/Sm^3 oil)
CO_2-only	-	-	5.22
IW500 3:12	1%	0.30	5.10
IW500 6:12	4%	0.35	5.22
IW500 9:12	6%	-0.01	5.47
IW500 12:12	8%	-0.46	5.84
IW750 3:12	3%	0.99	4.97
IW750 6:12	11%	1.69	5.10
IW750 9:12	17%	-0.06	6.09
IW750 12:12	21%	-1.31	6.97
IW1000 3:12	9%	2.11	4.84
IW1000 6:12	20%	0.47	6.01
IW1000 9:12	28%	-1.43	7.45
IW1000 12:12	34%	-2.55	8.59

The gas-oil mobility ratio displayed in Figure 4-16 shows that the case of IW500-3-12 gave the highest value of around 12, however this value is still way lower than the CO_2-only case which was more than 20. By increasing the rate to 1000 Sm3/day and injection interval to 12 months, a significant reduction of the gas-oil mobility to a value of about 2 was achieved. As such, the decrease in gas production with increasing water injection rate and injection intervals are correlated to the lower gas-oil mobility ratio.

The IW1000-12-12 achieved the lowest gas-oil mobility ratio, however it gave the highest water-oil mobility ratio. The water-oil mobility ratio value for the IW1000-12-12 was about three times of the IW500-3-12 and twice of the IW500-12-12. The correlation between water-oil mobility ratio and oil production rate is clear as shown in Figure 4-17. The higher the water injection rate and the higher water injection interval resulted in a lower oil production rate.

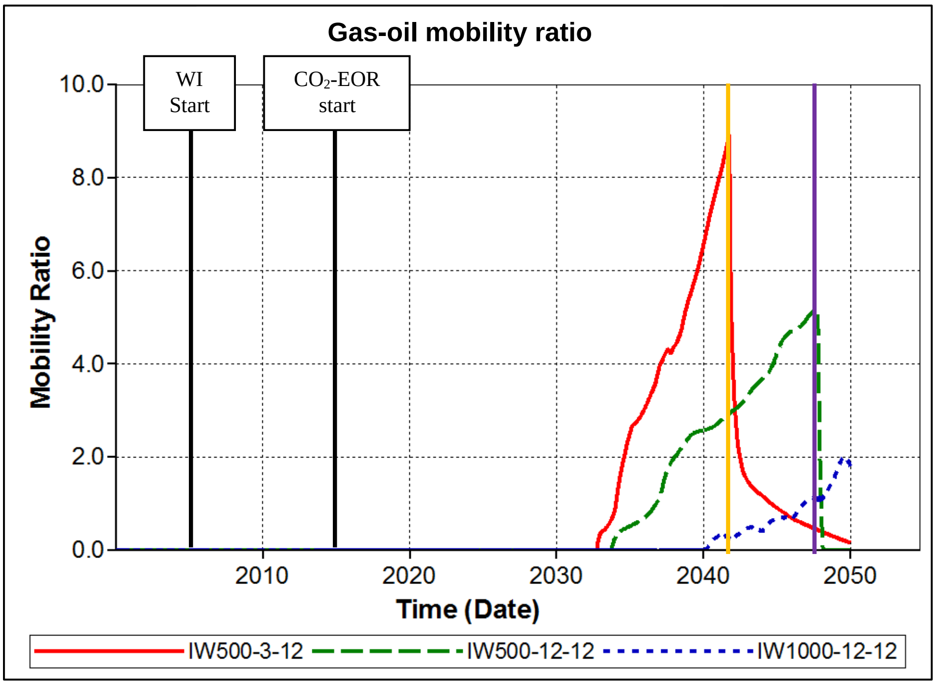


Figure 4-16- Gas-oil mobility ratio for IW500-12-12, IW500-3-12, and IW1000-12-12 at near wellbore (8,8,2). The vertical lines represent the production shut-in time: yellow is for the IW500-3-12 case and purple is for the IW500-12-12 case. Higher water injection rate and longer water injection interval led to lower gas-oil mobility ratio.

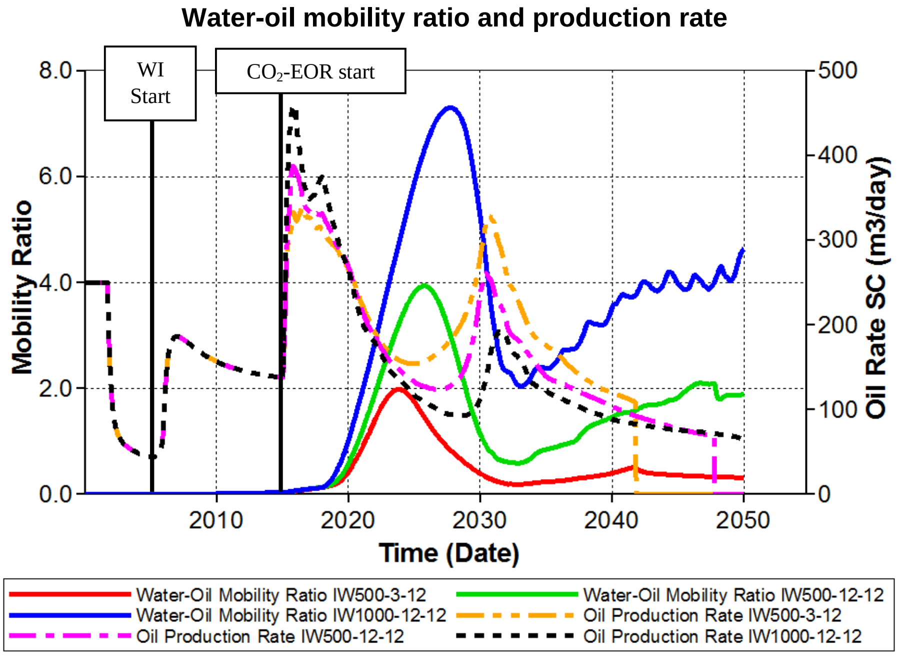


Figure 4-17- Water-oil mobility ratio and oil production of IW500-12-12, IW500-3-12, and IW1000-12-12 at near wellbore (8,8,2). Higher water injection rate and longer water injection interval increases water-oil mobility ratio, hence reduces oil production rate.

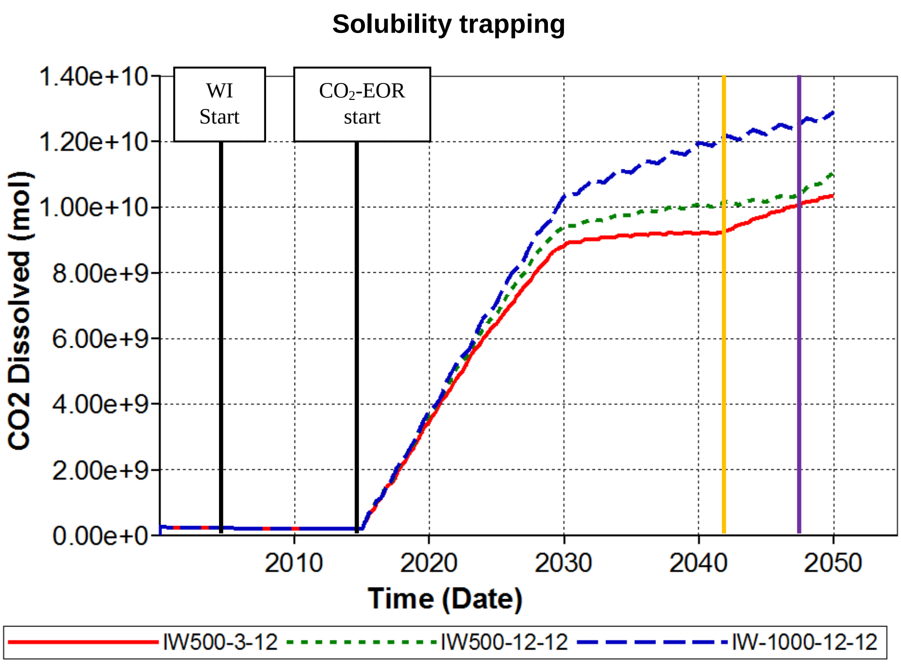


Figure 4-18- CO_2 solubility trapping of IW500-12-12, IW500-3-12, and IW1000-12-12. The vertical lines represent the production shut-in time: yellow is for IW500-3-12 and purple is for IW500-12-12. Higher and longer water injection intervals increases solubility trapping mechanism of CO_2.

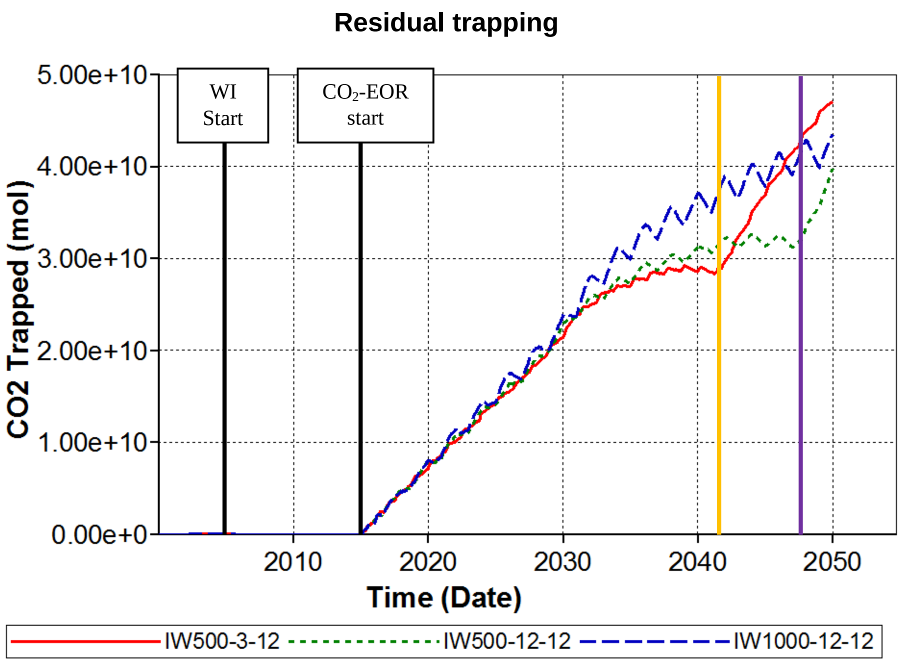


Figure 4-19- CO_2 residual trapping of IW500-12-12, IW500-3-12, and IW1000-12-12. The vertical lines represent the production shut-in time: yellow is for IW500-3-12 and purple is for IW500-12-12. Higher and longer water injection intervals increases residual trapping mechanism of CO_2

The solubility trapping of IW500-3-12, IW500-12-12 and IW1000-12-12 are shown in Figure 4-18. From the graph it can be seen that as the water injection rate increases, the solubility trapping increases. Also, as the water injection interval increases, the solubility trapping increases. This agrees with the findings in the solubility trapping in the previous subchapter.

A similar behavior for the residual trapping (Figure 4-19), however for the IW1000-12-12, a more pronounced zig-zag type trend (caused by intermittent water injection) was shown compared to the solubility trapping cases. The ranking in the residual trapping is the same as the ranking in the solubility trapping. The difference in the residual trapping is smaller between the cases. As a summary, in the residual trapping mechanism, the water injection rate and water injection length are important in increasing the residual trapping.

4.4 Co-optimization to increase the CO_2 stored and oil recovered

From the above subchapters, it was demonstrated that the shorter injection length showed better oil production rate, so the selected for the co-optimization are: IW500-3-12, IW750-3-12, and also IW1000-3-12. The co-optimization will be by increasing the water injection rate and/or injection interval in 2031 as shown in Table 4-6. Year 2031 was selected because a steep increase in the gas production was detected. So the approach for the optimization was to reduce the gas production.

Table 4-6- Water injection rate and injection interval length for IW co-optimization

Co-optimization start date	Water injection rate Sm^3/day	Water injection interval (on:off) Months:Months
4/1/2031	1000	6:12
4/1/2031	1000	12:12
4/1/2031	750	6:12
4/1/2031	750	12:12
4/1/2031	500	12:12

Figure 4-20, Figure 4-21, and Figure 4-22 show that the higher injection rate the faster the oil recovery response. For example in the case of IW500-3-12 the optimization started to take effect in around 2038 (7 years after rate change), for the higher rate cases of IW750-3-12 and IW1000-3-12 the effect started sooner, 2037 and 2036, respectively.

In terms of reduction of the gas production, the largest reduction was achieved by changing the water injection to the rate of 1000 Sm^3/day with interval of 12-12 during the optimization period. This resulted in a flat gas production rate for about 5 years before it continued to increase again. In other words, the gas production rate can be influenced by modifying the IW regime.

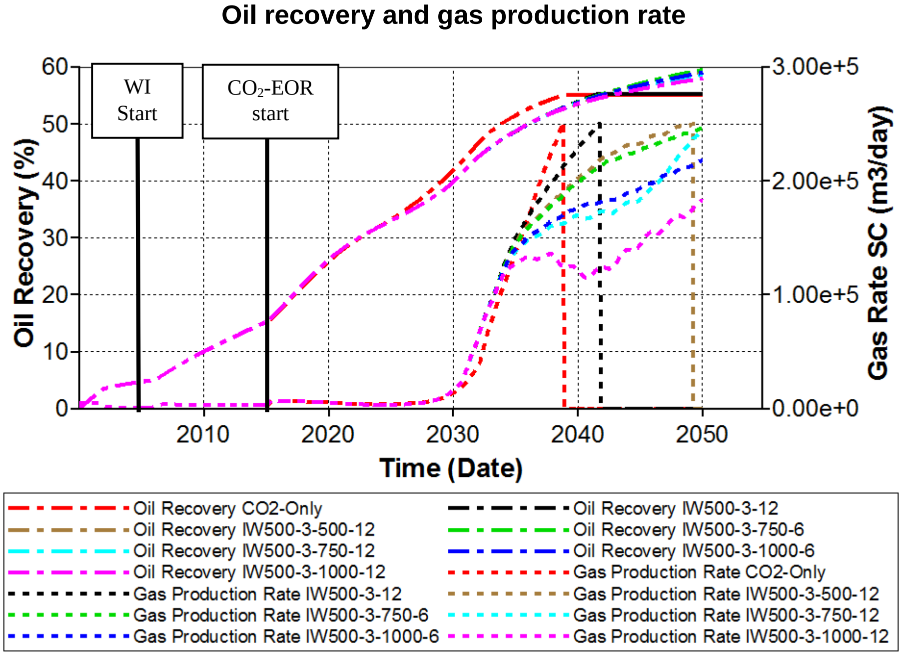


Figure 4-20- Oil recovery and gas production for CO_2-Only, IW500-3-12, and IW500-3-12's co-optimizations. The co-optimization cases have exceeded the CO_2-Only oil recovery

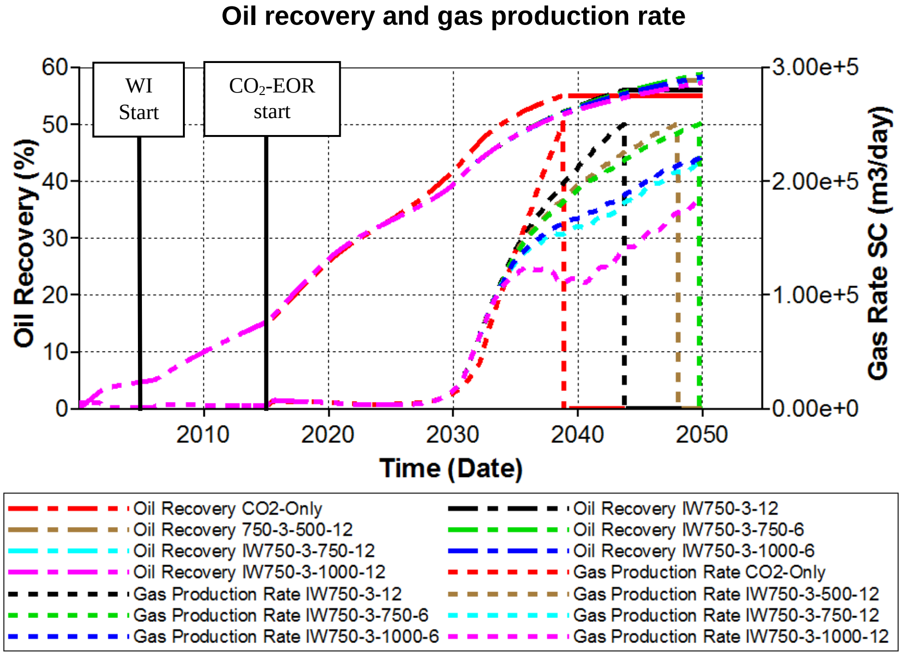


Figure 4-21- Oil recovery and gas production for CO_2-Only, IW750-3-12, and IW750-3-12's co-optimizations. The co-optimization cases have exceeded the CO_2-Only oil recovery

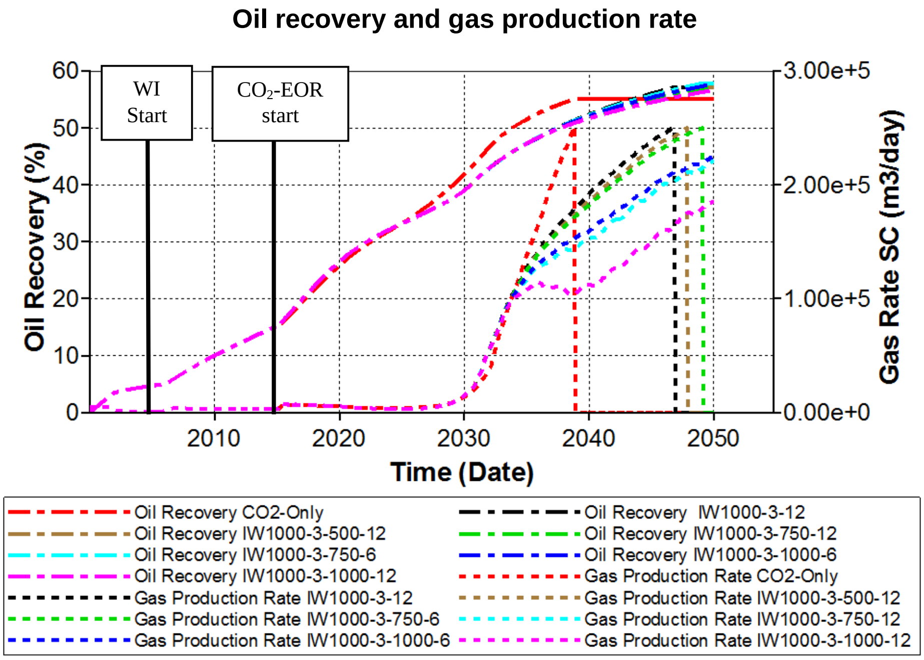


Figure 4-22- Oil recovery and gas production chart for CO_2-Only, IW1000-3-12, and IW1000-3-12's co-optimizations. The co-optimization cases have exceeded the CO_2-Only oil recovery.

As can be seen in Table 4-7, the optimized cases (where two water injection rates were indicated) increased the CO_2 stored compared to the corresponding un-optimized case. As stated previously the CO_2 stored was dependent on the water injection rate and the injection interval. The highest CO_2 stored was by the case of IW1000-3-1000-12 which has the highest water injection rate and longest water injection time interval while the least CO_2 stored was in the optimization case with the IW500-3-500-12 (lowest water injection rate).

There are 11 out of the 15 optimization cases that reduced the CO_2 UF below the CO_2-only case (5.22 tCO_2/Sm^3 oil), while storing more CO_2. The lowest CO_2 UF achieved was 4.15 tCO_2/Sm^3 oil from the IW500-3-750-6 case. CO_2 UF is a proportional to the CO_2 stored and the gained incremental oil. CO_2 UF reduction means larger increase of oil recovery than the increase of the CO_2 stored. One may conclude that it is possible to economically and practically co-optimize CO_2-EOR and CO_2-storage with indication of the decrease of the CO_2 UF.

Table 4-7- The CO_2 stored, oil recovery increase, and CO_2 UF for the co-optimized cases. Blue highlights marked original cases

Case	CO_2 stored increase compared to the CO_2-Only case (%)	Oil recovery increase compared to the CO_2-Only case (% OOIP)	CO_2 Utilization Factor (tCO_2/Sm^3 oil)
CO_2-only	-	-	5.22
IW500 3:12	1%	0.30	5.10
IW500-3-500-12	6%	3.93	4.22
IW500-3-750-6	8%	4.46	4.15
IW500-3-750-12	16%	3.64	4.68
IW500-3-1000-6	15%	3.97	4.57
IW500-3-1000-12	28%	2.98	5.39
IW750 3:12	3%	0.99	4.97
IW750-3-500-12	8%	2.73	4.61
IW750-3-750-6	9%	3.71	4.39
IW750-3-750-12	18%	2.89	5.00
IW750-3-1000-6	16%	3.32	4.79
IW750-3-1000-12	29%	2.32	5.67
IW1000 3:12	9%	2.11	4.84
IW1000-3-500-12	10%	2.00	4.94
IW1000-3-750-6	11%	2.79	4.74
IW1000-3-750-12	19%	2.23	5.28
IW1000-3-1000-6	18%	2.68	5.05
IW1000-3-1000-12	30%	1.62	5.99

4.4.1 The effect of modifying water injection configuration towards mobility ratio

In the cases of IW750-3-750-6 and IW1000-3-750-6 for example, the gas production rate reached the constraint limit of 250M Sm^3/day. On the other hand the IW500-3-750-6 case which uses the same mitigation plan held out the gas production until the end of simulation/production. The gas-water mobility ratio Figure 4-23 demonstrates that increasing the water injection rate has more impact on the gas production mitigation than increasing the water injection length.

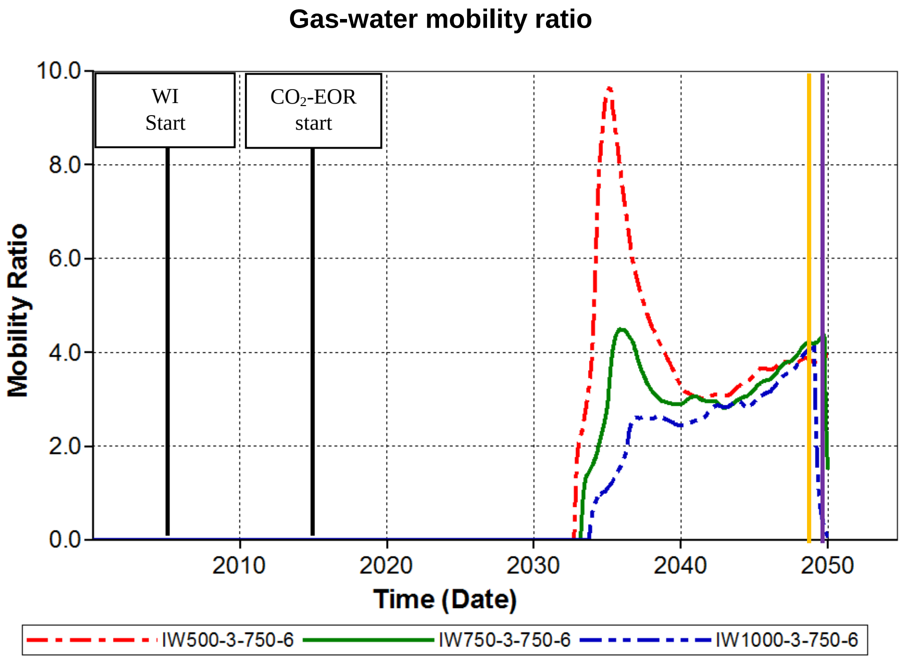


Figure 4-23- Gas-water mobility ratio of IW500-3-750-6, IW750-3-750-6, and IW1000-3-750-6 at near wellbore (8,8,2). The vertical lines represent the production shut-in time: yellow is for IW1000-3-750-6 and purple is for IW750-3-7506.Without increasing the water injection rate, the gas production mitigation is less effective.

The gas-oil mobility ratio was able to be reduced in the optimized cases as shown in Figure 4-24. In the case of 500 Sm^3/day water injection rate, increasing the water injection to 1000 Sm^3/day for 12 months period reduces the gas-oil mobility ratio by around 66%. When the increase is to 750 Sm^3/day for 6 months the gas-oil mobility ratio decrease by 35%. A similar value also attained in the IW1000-3 optimization cases. The effect of reduction in gas-oil mobility ratio can be seen in lower gas production in the case of the optimized cases and its corresponding un-optimized case.

The water-oil mobility ratio increases with the water injection rate and injection length as shown in Figure 4-25. When the injection was changed to 1000 Sm^3/day and 12 months injection period, the water-oil mobility ratio increased significantly. The increase even reached 15 fold for IW-500-3-1000-12. When the injection was changed to 750 Sm^3/day and 6 months injection period, the water-oil mobility ratio increased by around three fold.

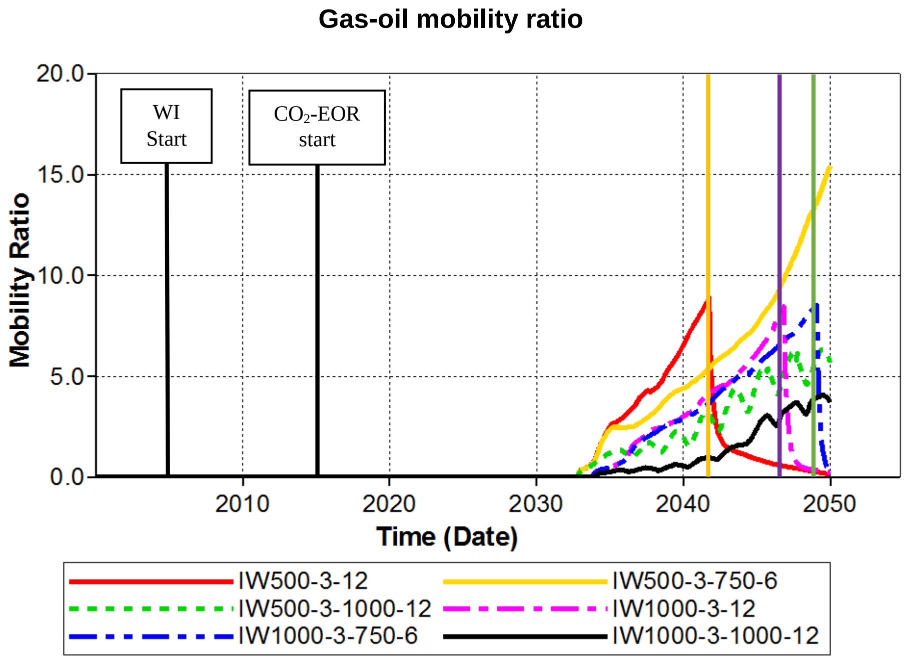


Figure 4-24- Gas-oil mobility ratio for example cases IW500-3-750-6, IW500-3-1000-12, IW1000-3-750-6, and IW1000-3-1000-12 at near wellbore (8,8,2). *The vertical line represent production termination time: yellow is for IW500-3-12, purple is for IW1000-3-12, green is for IW1000-3-750-6. IW optimization shows improvement in gas-oil mobility ratio.*

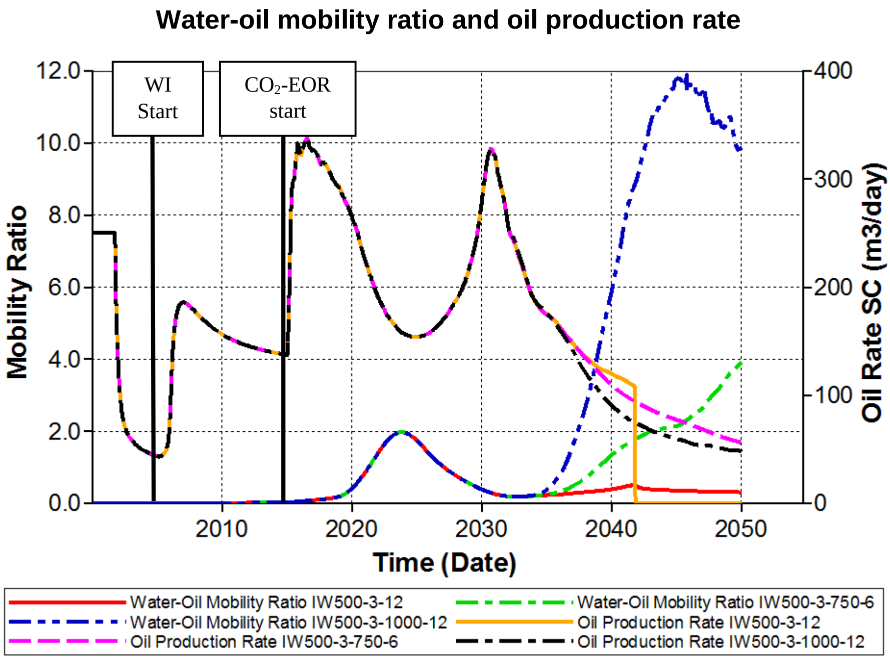


Figure 4-25- Water-oil Mobility Ratio and oil production rate for example cases IW500-3-750-6, IW500-3-1000-12 at near wellbore (8,8,2). *The oil production ranking is inverse to the water-oil mobility ratio ranking*

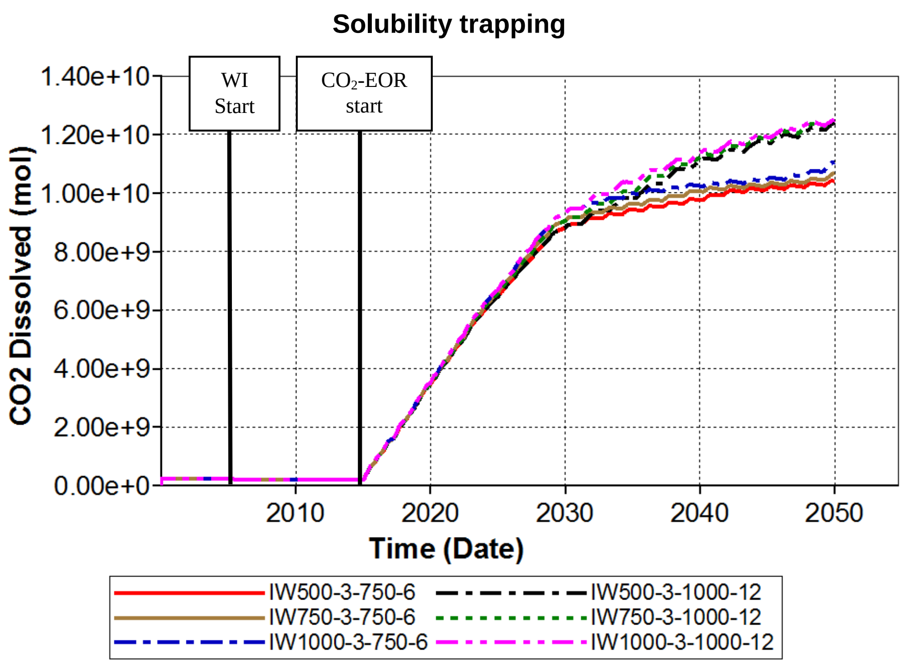


Figure 4-26-CO_2 solubility trapping of example cases IW500-3-750-6, IW500-3-1000-12, IW-750-3-750-6, IW-750-3-1000-12, IW1000-3-750-6, and IW1000-3-1000-12. Higher injection rate leads to better solubility trapping

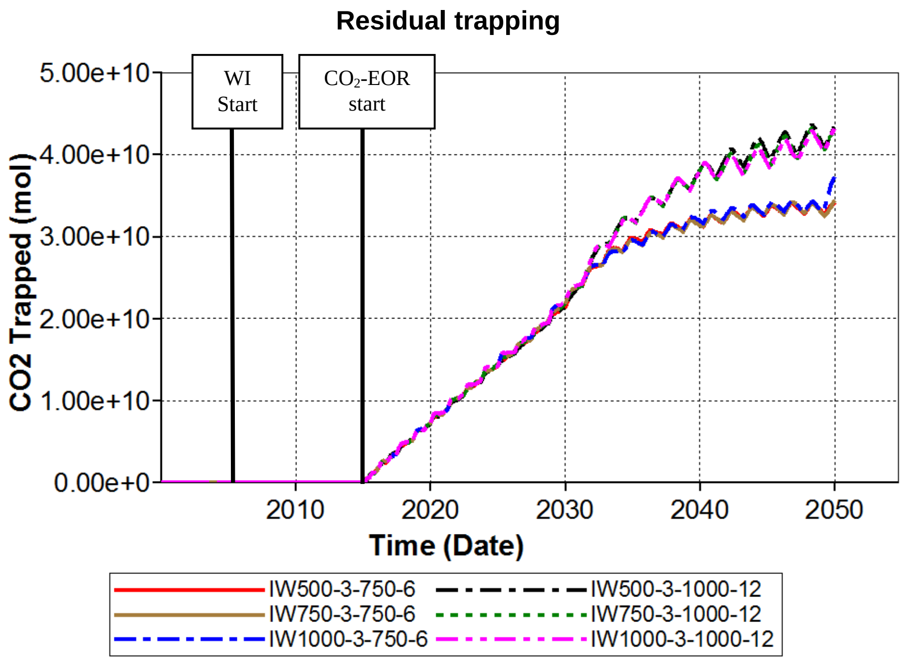


Figure 4-27- CO_2 residual trapping of example cases IW500-3-750-6, IW500-3-1000-12, IW-750-3-750-6, IW-750-3-1000-12, IW1000-3-750-6, and IW1000-3-1000-12. Higher injection rate leads to better residual trapping.

From the work in this subchapter it can be learned that modifying the water injection rate and injection period will change the gas-water, gas-oil and water-oil mobility ratios. When the water injection and water injection period increases then the gas-oil mobility will decrease, resulting in lower gas production. The co-optimization also led to the increase of solubility trapping and residual trapping as shown in Figure 4-26 and Figure 4-27. These events leads to more CO_2 to be left in the reservoir.

As such, this subchapter shows the importance of adjusting the water injection rate and water injection length regime across the CO_2-EOR lifetime, by co-optimizing the IW. Since the water injection rate modifies the fluid mobility, it should be assessed carefully so that it can co-optimize the oil recovery and the CO_2 stored during the CO_2-EOR.

4.5 Objective Function as candidacy selection process

The co-optimization cases results show that the best case in term of oil recovery is not the best case in term of the CO_2 stored. The co-optimization case to be chosen would depend on the objective of the field operator. The selection will be nominated by using a proposed D (Delta)-Value process. The D-Value is a difference parameter between the maximum value of the set and its own value, then an objective function calculation will be done to conduct the co-optimization. The higher the D value, the closer it is to the maximum achievable value. The use of D-Value is proposed as a simple way to normalize the selection parameters values in the range of [0,1]. The D-Value in Table 4-8 is calculated as the following:

$$D - Value = 1 - \frac{Max\ achievable\ Value - Current\ Value}{Max\ achievable\ Value}$$

The objective function is a tool to respect the result parameters that would affect the co-optimization. Three objective functions will be used: 50-50 (equal importance of oil recovery and CO_2 storage), 25-75 (More importance on CO_2 storage), and 75-25 (more importance on oil recovery).

Table 4-8-D-Value of CO_2 stored increase and oil recovered increase

Case	CO_2 stored increase compared to the CO_2-Only case (%)	Oil recovery increase compared to the CO_2-Only case (% OOIP)	CO_2 stored increase compared to the CO_2-Only case (D-Value)	Oil recovery increase compared to the CO_2-Only case (D-Value)
IW500 3:12	1%	0.30	0.03	0.07
IW500-3-500-12	6%	3.93	0.20	0.88
IW500-3-750-6	8%	4.46	0.27	1.00
IW500-3-750-12	16%	3.64	0.53	0.82
IW500-3-1000-6	15%	3.97	0.50	0.89
IW500-3-1000-12	28%	2.98	0.93	0.67
IW750 3:12	3%	0.99	0.10	0.22
IW750-3-500-12	8%	2.73	0.27	0.61
IW750-3-750-6	9%	3.71	0.30	0.83
IW750-3-750-12	18%	2.89	0.60	0.65
IW750-3-1000-6	16%	3.32	0.53	0.74
IW750-3-1000-12	29%	2.32	0.97	0.52
IW1000 3:12	9%	2.11	0.30	0.47
IW1000-3-500-12	10%	2.00	0.33	0.45
IW1000-3-750-6	11%	2.79	0.37	0.63
IW1000-3-750-12	19%	2.23	0.63	0.50
IW1000-3-1000-6	18%	2.68	0.60	0.60
IW1000-3-1000-12	30%	1.62	1.00	0.36

Table 4-9- Objective function results

Case	Even objective	More storage	More oil Recovery
	50-50	75-25	25-75
IW500 3:12	0.33	0.18	0.48
IW500-3-500-12	0.55	0.37	0.74
IW500-3-750-6	0.62	0.43	0.80
IW500-3-750-12	0.64	0.60	0.68
IW500-3-1000-6	0.67	0.58	0.76
IW500-3-1000-12	0.74	0.83	0.65
IW750 3:12	0.56	0.34	0.78
IW750-3-500-12	0.48	0.36	0.60
IW750-3-750-6	0.54	0.41	0.67
IW750-3-750-12	0.56	0.58	0.54
IW750-3-1000-6	0.59	0.56	0.62
IW750-3-1000-12	0.66	0.81	0.51
IW1000 3:12	0.53	0.40	0.65
IW1000-3-500-12	0.43	0.38	0.49
IW1000-3-750-6	0.49	0.42	0.55
IW1000-3-750-12	0.49	0.56	0.41
IW1000-3-1000-6	0.52	0.55	0.49
IW1000-3-1000-12	0.58	0.79	0.36

Table 4-10- Cases ranking

Rank	Even objectives	More storage	More recovery
1	IW500-3-1000-12	IW500-3-1000-12	IW500-3-750-6
2	IW750-3-1000-12	IW750-3-1000-12	IW500-3-1000-6
3	IW500-3-1000-6	IW1000-3-1000-12	IW500-3-750-12

The objective function calculation result can be observed in Table 4-9 and ranked in Table 4-10. Since there are overlapping cases in each category, there are total 6 cases in the top three brackets. It is interesting to see that out of 4 of the 6 cases that enter the top three belong to the IW500-3 sets. It shows that in order to co-optimize oil recovery and the CO_2 stored it would be best to start with low water injection rate and short water injection period then increase the rate and the length later.

4.6 Sensitivity cases of the reservoir parameters

In this subchapter, the robustness of the co-optimization approach was assessed by varying several reservoir parameters as the following: Reduction in gas mobility, reduction in reservoir permeability, increase in vertical permeability, and reduction in salinity. The co-optimization case of IW500-3-750-6 and the CO_2-Only case are chosen here.

4.6.1 Low gas mobility study

In this sensitivity study, the gas mobility was reduced by 50%. The decrease in gas mobility is represented by reduction of the gas relative permeability shown in Figure 4-28. As previously discussed in this chapter, as expected, reducing gas-oil mobility ratio lowers the gas production, thus increasing the CO_2 stored, hence higher oil recovery (Figure 4-29).

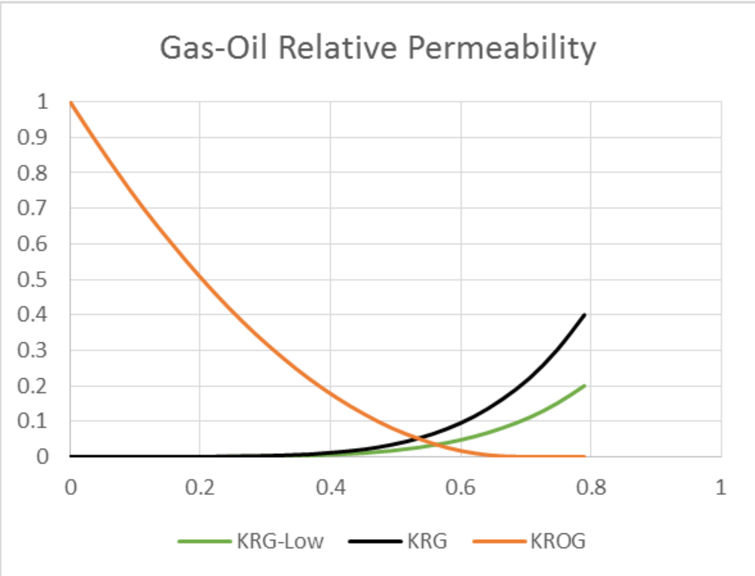


Figure 4-28- Gas-oil relative permeability. Krg-Low represents the low gas mobility condition.

The comparison of oil recovery and the CO_2 stored in this sensitivity cases and the original cases can be seen in Table 4-11. In the low gas mobility case, the IW500-3-750-6 approach in this sensitivity study was able to further reduce the gas production and resulted in the increase of oil recovery by 1.54% OOIP compared to the CO_2-Only approach. In the CO_2-Only approach, the CO_2 stored in this case compared to the original case was increased by 15%.

Table 4-11- CO_2 stored and oil recovery increased in the low gas mobility study

Case	**CO_2 stored increase compared to the original CO_2-Only case (%)**	**Oil recovery increase compared to the original CO_2-Only case (% OOIP)**
IW500-3-750-6 (original)	8%	4.46
CO_2-Only (low gas mobility)	15%	4.28
IW500-3-750-6 (low gas mobility)	34%	5.82

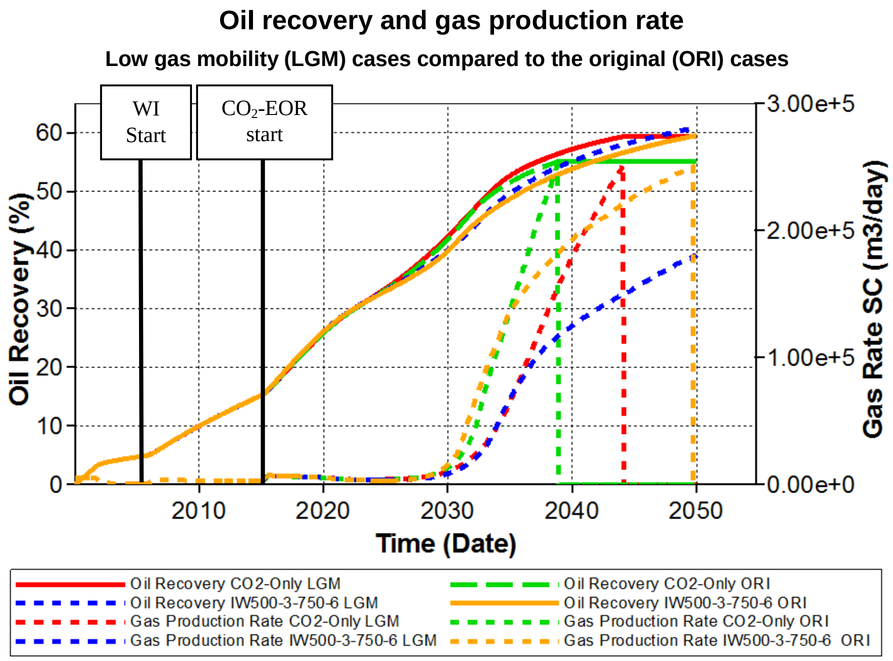


Figure 4-29- Oil recovery and gas production rate of the low gas mobility sensitivity study. The CO_2-Only case in this low gas mobility study reached the gas production constraint in March 2044, longer than in the original CO_2-Only case which met the gas production constraint in November 2038.

4.6.2 Low permeability study

In this study, the permeability was reduced from 200md to 100md, while the anisotropy stays at 0.01. The gas production in the low permeability cases was lower compared to the original cases as shown in Figure 4-30, thus increases the CO_2 stored. In this sensitivity study, the increase was 61% for the CO_2-Only case and 63% for the IW500-3-750-6 case as shown in Table 4-12. However, the optimized Interwater case has lower oil recovery than the CO_2-Only case in low permeability reservoir i.e. The Interwater optimization should be based on each reservoir characteristics

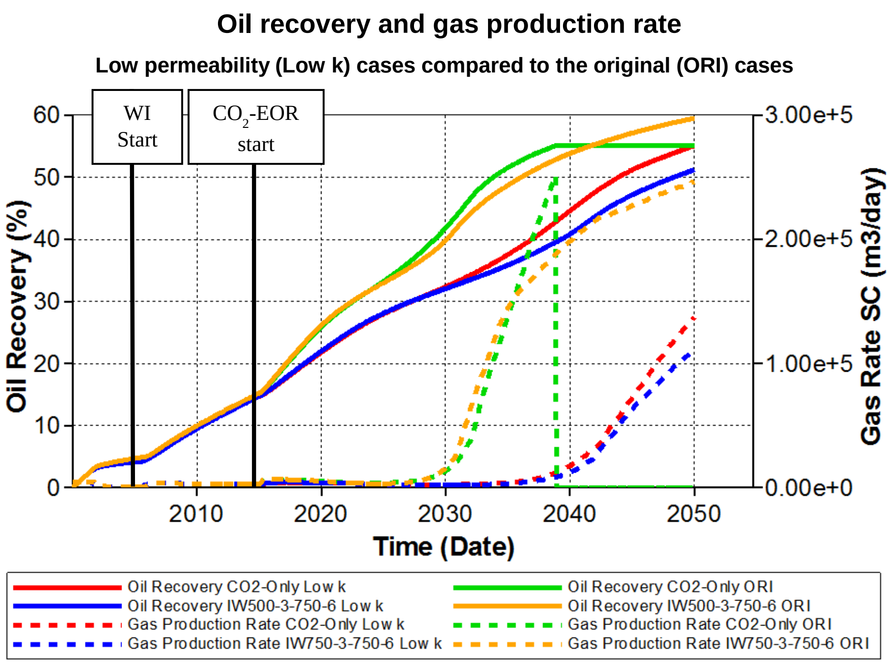


Figure 4-30- Oil recovery and gas production rate of the low permeability sensitivity study. The CO_2-Only case in this low gas mobility study never reached the gas production constraint, while the original CO_2-Only case met the gas production constraint in November 2038.

Table 4-12- CO_2 stored increase and oil recovered increase in low permeability study

Case	**CO_2 stored increase compared to the original CO_2-Only case (%)**	**Oil recovery increase compared to the original CO_2-Only case (% OOIP)**
IW500-3-750-6 (original)	8%	4.46
CO_2-Only (low permeability)	61%	0.03
IW500-3-750-6 (low permeability)	63%	-3.84

4.6.3 High anisotropy study

In this high anisotropy study, the value was increased from 0.01 to 0.1, i.e. kv increased from 2 md to 20 md, while the kh stays at 200 md. The oil recovery improvement in this high anisotropy study by the IW500-3-750-6 approach was increased by about 3.2% OOIP relative to the CO_2-Only approach (Figure 4-31). In the CO_2-Only case, the production shut-in was due to the steep oil production rate decline after the gas breakthrough (Figure 4-32).

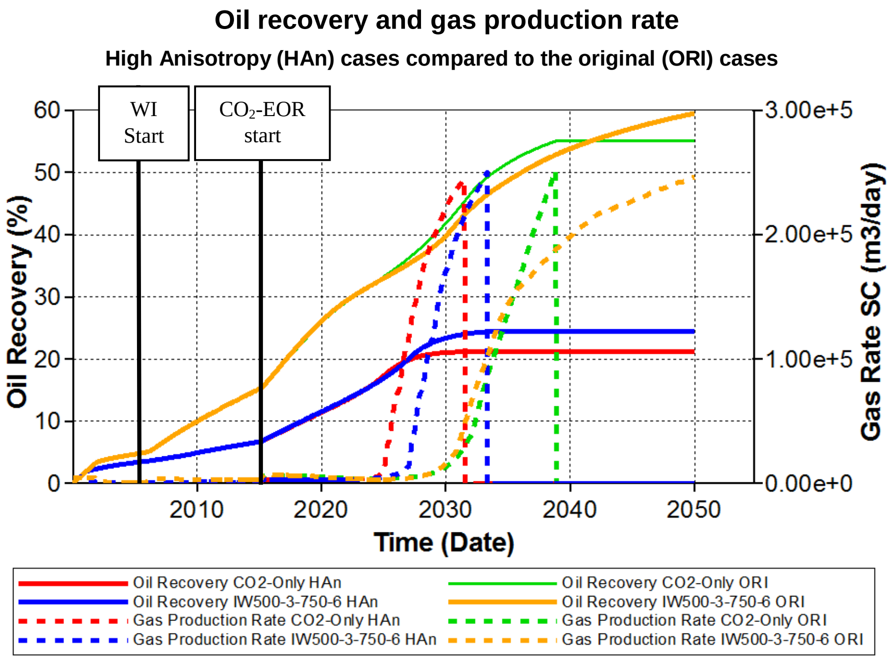


Figure 4-31- Oil recovery and gas production rate of the high anisotropy sensitivity study. The high anisotropy cases production life are much shorter than the original case.

Table 4-13- CO_2 stored increase and oil recovered increase in the high anisotropy study

Case	CO_2 stored increase compared to the original CO_2-Only case (%)	Oil recovery increase compared to the original CO_2-Only case (% OOIP)
IW500-3-750-6 (original)	8%	4.46
CO_2-Only (high anisotropy)	-36%	-33.88
IW500-3-750-6 (high anisotropy)	-27%	-30.65

As shown in Table 4-13, the oil recovery in this high anisotropy study is lower than the original case. This is expected since the greater vertical communication would increase the tendency of gravity override, in which will decrease the vertical sweep efficiency. As the gravity override effect increases, the breakthrough time accelerated, and resulted in more gas production. This faster gas breakthrough decreases the CO_2 stored by 36% in the CO_2-Only approach and 27% in the IW500-3-750-6 approach. This sensitivity study shows that the implementation of the Interwater approach was beneficial.

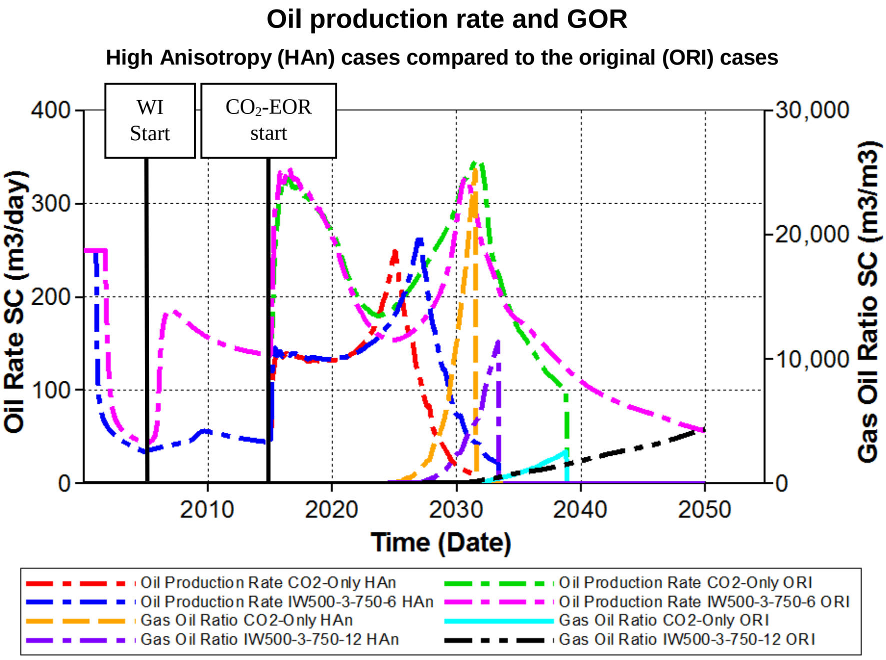


Figure 4-32- Oil production rate and GOR of the high anisotropy sensitivity study. The oil production declines are very steep compared to the original cases.

4.6.4 Low salinity study

In this sensitivity study, the water salinity was reduced from 0.1 mol NaCl/kg H_2O to 0.001 mol NaCl/kg H_2O. The oil recovery and gas production trends (Figure 4-33) are similar to the original case. Table 4-14 shows that the oil recovery and CO_2 stored are similar to the original cases of CO_2-Only and the IW500-3-750-6. A very slight increase in solubility trapping was observed as shown in Figure 4-34. The low salinity simulation study here was not extensive.

Table 4-14- CO_2 stored increase and oil recovered increase in the low salinity study. The CO_2 stored increase uses 3 decimals to show the similarities.

Case	CO_2 stored increase compared to the original CO_2-Only case (%)	Oil recovery increase compared to the original CO_2-Only case (% OOIP)
IW500-3-750-6 (original)	4.46	7.528
CO_2-Only (low salinity)	-0.16	-0.122
IW500-3-750-6 (low salinity)	4.32	7.452

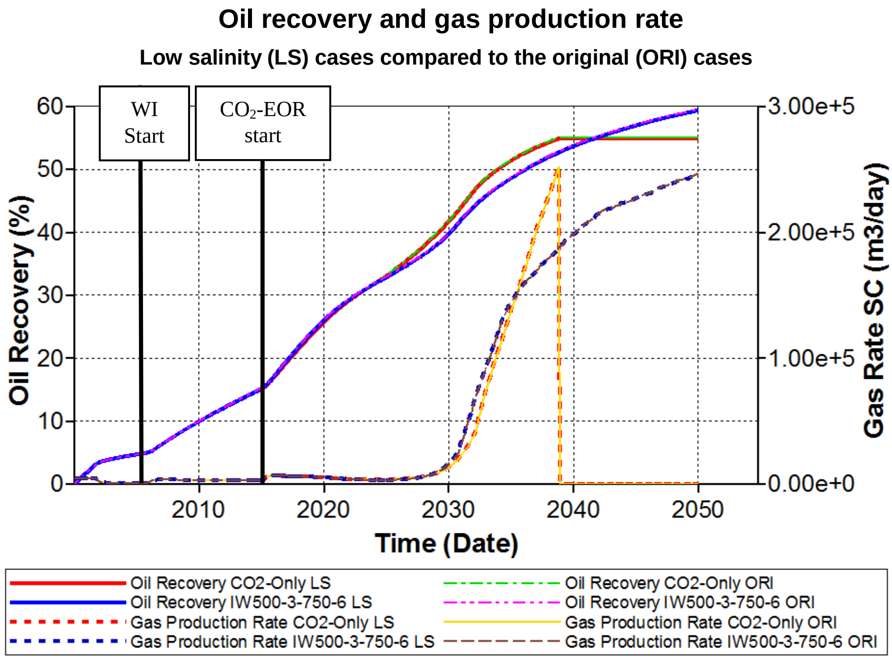


Figure 4-33- Oil recovery and gas production in the low salinity sensitivity study. The oil recovery and gas production behavior are similar to the original cases.

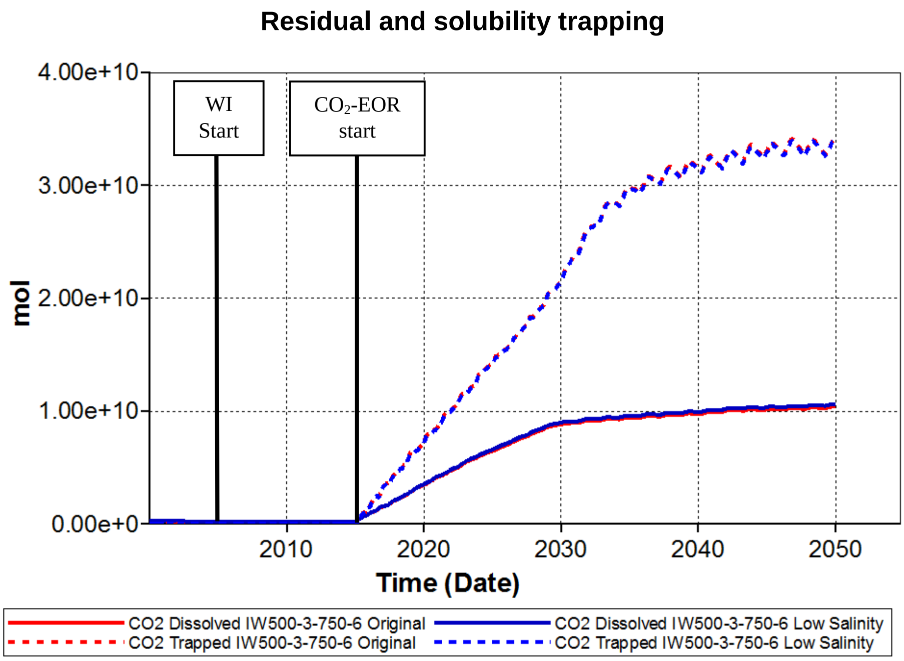


Figure 4-34- CO_2 residual and solubility trapping comparison between low salinity cases and original cases. The low salinity cases and the original cases show an almost identical value in the residual trapping. In the solubility trapping, the low salinity case is very slightly higher.

5. Summary and Conclusion

Based on this study, different approaches were assessed using CO_2 continuous injection as a base case reference. The following are summary and conclusions.

1. The approach of injecting water into the top layer and injecting continuous CO_2 into the bottom layer was successful in reducing the gas production, thus increasing the CO_2 stored. It was found that the continuous water injection reduced the oil recovery while the Intermittent water injection increased both CO_2-storage and oil recovery.

2. In the co-optimized Interwater approach, the highest stored CO_2 increase was by the IW-1000-3-1000-12 case: Water injection of 1000 Sm^3/day with 3 months interval then the interval was increased to 12 months with same injection rate. The total CO_2 stored increased by 30% while increasing the oil recovery by 1.62% OOIP.

3. The best oil recovery in this project was achieved by the co-optimized intermittent water approach of water injection rate of 500 Sm^3/day for 3 months interval then increase the rate and interval to 750 Sm^3/day for 12 months respectively. The oil recovery increased by 4.46% OOIP and total CO_2 stored increased by 8%.

4. Lowest reduction in the CO_2 utilization factor (ratio of the stored CO_2 to the recovered oil) was obtained by applying intermittent water injection of 500 Sm^3/day for 3 months and then injecting water at 750 Sm3/day for 6 months (IW500-3-750-6). In this case the CO_2 UF was reduced from 5.22 tCO_2/Sm^3 oil to 4.15 tCO_2/Sm^3 oil. This indicates economically and practically sound case.

Reservoir parameter sensitivity study was done to investigate the effect of reservoir parameters change towards oil recovery and the CO_2 stored in the CO_2-Only approach and in the co-optimized Interwater approach of IW500-3-750-6:

1. **In the low gas mobility case,** the CO_2 stored and the oil recovery are higher compared to the original cases. The application of the co-optimized Interwater was shown to have limited improvement in oil recovery, but still significant improvement in the amount of CO_2 stored.

2. **In the low permeability case,** the CO_2 stored is higher compared to the original cases. Comparing this sensitivity cases to the original cases, the CO_2 continuous injection approach has a slight increase in oil recovery. However, the optimized Interwater case approach has lower oil recovery than the CO_2-Only approach in low permeability reservoir i.e. optimization should be based on each reservoir characteristics.

3. **In the high anisotropy case,** the CO_2 stored and the oil recovery is much lower compared to the original cases. The Interwater case was able to mitigate the negative effect of high anisotropy reservoir.

4. **In the low salinity case,** the CO_2 stored and the oil recovery is similar with the original case. Slight increase in the solubility trapping is observed. However, the simulation study in this case was not extensive.

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