Centre for Petroleum Studies

Design of Optimal Storage and Recovery Strategies of Carbon Dioxide using the Wytch Farm Reservoir Model

By

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A report submitted in partial fulfilment of the requirements for the MSc and/or the DIC.

September 2011

DECLARATION OF OWN WORK

I declare that this thesis *Design of Optimal Storage and Recovery Strategies of Carbon Dioxide using the Wytch Farm Reservoir Model* is entirely my own work and that where any material could be construed as the work of others, it is fully cited and referenced, and/or with appropriate acknowledgement given.

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ABSTRACT

Carbon dioxide (CO_2) injection into hydrocarbon reservoirs to achieve Enhanced Oil Recovery (EOR) and Carbon Capture and Sequestration (CCS) is one of the main challenges faced by the oil industry. The effective implementation of this process in oil reservoirs will provide both the environmental advantage of reductions in CO_2 emissions while maximizing oil recovery. The objective of this study is to find injection strategies that would achieve optimum CO_2 storage and oil recovery in the reservoir.

We perform compositional simulations for a section of a reservoir model representing the Wytch Farm oilfield which is the Europe's largest onshore field. This involved analyzing the candidate reservoir for CO_2 flooding and comparing different injection strategies which were gas injection after water flooding (GAW) and water alternating gas (WAG) while testing the effect of nitrogen in the injection stream and the mass evaluation of the net CO_2 stored, to determine the different trapping mechanisms in various phases.

The results show that CO_2 CCS and EOR process is a possibility for the reservoir and that optimal storage and recovery strategies of CO_2 for the reservoir model are based on the availability of the injection gas and the objective of the injection process. The GAW process involves re-cycling due to CO_2 breakthrough. The WAG process would give long-term CO_2 storage mechanisms and reduce the risk of mobile CO_2 leakage to the surface.

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Abstract

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Introduction

Carbon Capture and Storage (CCS), the collection of CO_2 from industrial sources and its injection underground, could contribute significantly to reductions in atmosphere emissions of greenhouse gases (IPCC, 2005). Possible sites for injection include coalbeds, deep saline aquifers, and depleted oil and gas reservoirs. Although aquifers have the greatest storage potential, injecting CO_2 into depleted oil and gas reservoirs can provide additional hydrocarbon production and improve storage security (Qi *et al*., 2008).

Carbon dioxide has been injected for Enhanced Oil Recovery (EOR) since the 1970s. The main factor impacting the efficiency of EOR with CO_2 injection is the miscibility of CO_2 in the oil phase (Orr and Taber, 1989, Blunt *et al*., 1993, Orr *et al*., 1995). At pressures greater than the minimum miscibility pressure (MMP), oil and CO_2 are mutually soluble. The dissolved CO_2 reduces the viscosity of oil and causes the swelling of the oil phase, hence improving the ability to flow through the reservoir rock. Screening criteria for selecting reservoirs where CO_2 may sustain or increase the production have been proposed. To date, CO_2 injection projects have focused on oil with densities ranging from 29 to 48 ^{o} API (855 to 711 kg/m^3) and reservoir depths from 760 to 3700 m (2600ft to 12000ft) (Taber *et al*., 1997). To date, injection processes have been designed to minimize the amount of CO_2 injected per barrel of oil produced, thereby minimizing the purchased cost of CO_2. However, when the goal is to store carbon dioxide, the design question changes significantly (Kovscek, 2002). The design for oil recovery should achieve maximum emplacement of the injected CO_2 as well as to maximize oil recovery.

CO_2 flooding has the disadvantage that the unfavorable mobility ratio between the oil and CO_2 can result in early CO_2 breakthrough because of channeling of CO_2 through the reservoir fluids. Water alternating gas (WAG) injection can be successfully applied to improve sweep efficiency and delay CO_2 breakthrough. Injecting CO_2 into depleted oil and gas reservoirs for EOR results in additional hydrocarbon recovery generating revenue to off-set the cost of capture and storage (Lake, 1989).

This paper will focus on the optimal storage and recovery injection strategies for carbon dioxide in a section of the Wytch Farm reservoir. The Sherwood reservoir is a heterogeneous arkosic fluvio-lactustrine deposit which is capped by the Mercia mudstone group believed to represent an extensive playa deposit. Dip closure to the east and west and sealing faults along the northern and southern boundaries of the reservoir provide the trap. The Wytch Farm oilfield is located in Poole, south coast UK, in Dorset, and extends offshore beneath Poole Harbour and the Isle of Purbeck. It is Europe's largest onshore oilfield. The Sherwood reservoir stretches both onshore and offshore with one third of the reservoir offshore (McKie *et al*., 1998). The reservoir model and fluid are summarized, the results of the various injection and optimization methods, the storage capacity are analyzed using compositional simulation to account for recovery and storage potential of the model.

CO_2 Storage Mechanisms in Oil Reservoirs

Figures 1and 2 describe the relationship between temperature, pressure and depth on CO_2 properties. The subsurface storage of CO_2 is accomplished at supercritical conditions. To ensure this, both the phase behavior of CO_2 and the reservoir conditions must be understood, since the reservoir temperature and pressure conditions are likely to change thorughout the life of a CO_2 storage project (Kamel *et al*., 2004). Not all of the CO_2 that is injected can be produced back at the production wells. Some will be stored by trapping mechanism described below.

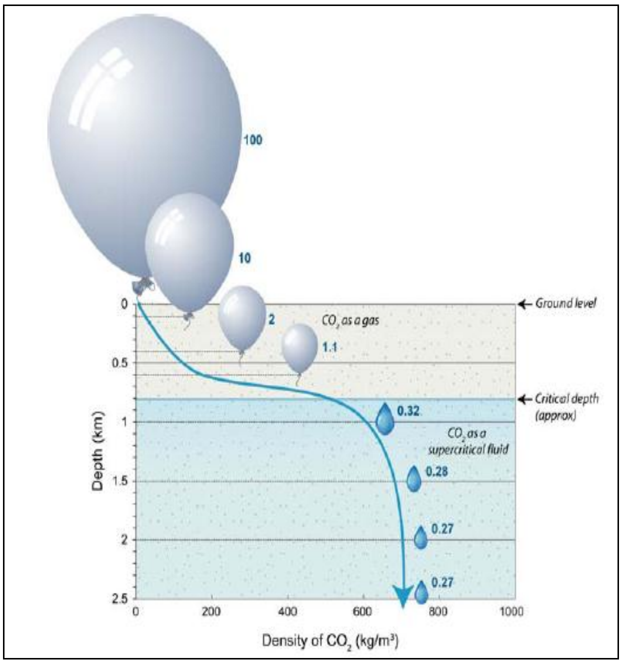

Figure 1: CO_2 volume with depth (CO2CRC).

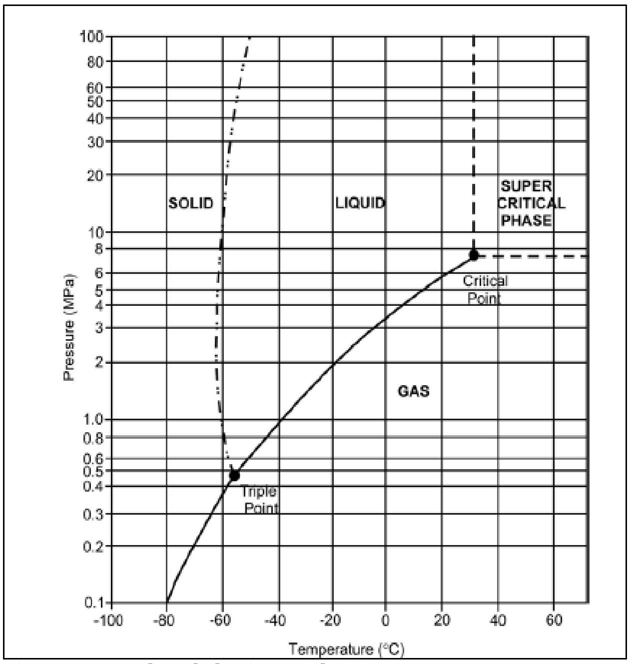

Figure 2: CO_2 phase behavior (Bachu, 2000).

There are four main CO_2 storage mechanisms in porous media underground, such as oil reservoirs and saline aquifers, including:

a) *Structured and stratigraphical trapping*: This is the main form of CO_2 storage after CO_2 injection, in which mobile CO_2 gas is retained under buoyancy forces by impermeable barriers, in analogy to natural gases. Similar mechanism have held oil and gas underground for million of years (Chadwick et al., 2008). The traps are comprised of salts, shales or clay which need not be completely impermeable, but have pore spaces that are so small that the CO_2 has sufficient pressure to enter (Blunt, 2010). Structural trapping (impermeable seals) has been heavily relied upon to trap CO_2 in current storage projects. This has been considered a primary trapping mechanism in well characterized formations. However the reliability of the seals overlaying the aquifer is uncertain and there will always be a possibility of CO_2 leaking back into the atmosphere. The main setback with this mechanism will be accurately determining the extent and integrity of the seal. Caprock quality is normally determined by the degree of quartz cementation and digenetic mineralogy (Armitage *et al.*, 2010).

b) *Residual gas (trapping):* This is the CO_2 gas remained in small pores due to capillary forces after CO_2 displacement of water (Chadwick et al., 2008).

c) *Dissolution trapping*: This is formed due to CO_2 dissolved in formation water, which can be the main and the safest CO_2 storage mechanism (Chadwick et al., 2008). Over hundreds to thousands of years, the CO_2 will dissolve in the formation brine forming a denser phase that will sink. CO_2 at high pressure has a reasonably high solubility in water, although this solubility decreases as brine becomes more saline (Blunt, 2010). Dissolution and precipitation both render the CO_2 less mobile over tie. The storage security increases over hundreds to thousands of years. The problem is that these are slow processes: in the worst case, much of the CO_2 may already have escaped to the surface (Ennis-King *et al*., 2002, Xu *et al*., 2003. Hesse *et al*, 2007).

d) *Mineral trapping*: This may occur when CO_2 reacts with minerals in formation rocks and water to form solid carbonates and aqueous complexes, but the reaction is slow and its contribution to storage capacity is usually small. In principle, most of injected CO_2 will be constrained by structure and residual gas trapping in early stages, and then slowly transferred to dissolution and mineral trapping for long-term storage. (Bachu *et al*., 2011).

The mass of CO_2 in place before injection for the reservoir can be estimated using (Bachu *et al.*, 2011):

$$M_{CO_2} = \rho_{CO_2 r} \times \lfloor R_f \times A \times h \times \phi \times (1\text{-}S_w) \rfloor \quad (1)$$

Converting the hydrocarbon pore volume, PV (A×h) of the hydrocarbon to mass of CO_2 based on the reservoir properties and density of CO_2 injected as a supercritical fluid of density 710 kg/m^3(Figure 1) the storage capacity is 16×10^8 kg (16×10^5 tonnes).

For a flooded reservoir with aquifer influx and water injection, we have;

$$M_{CO_2} = \rho_{CO_2 r} \times \lfloor R_f \times A \times h \times \phi \times (1\text{-}S_w) \rfloor - V_{inj} + V_{pw} \quad (2)$$

where $\rho_{CO_2 r}$ is the CO_2 density at reservoir (kg/m^3), R_f is the recovery factor which is 45% for the wytch farm model, A is area, h is thickness, ϕ is porosity, S_w is the water saturation in the reservoir, is the volume of injected, gas or solvent (for flooded reservoirs) and V_{pw} is the volume of produced water. The volumes of injected and/ or produced water, solvent or gas are calculated from production records. The total theoretical storage capacity of CO_2 in a combined reservoir can be divided into two parts, respectively contributed by the oil reservoir and its associated aquifers (see Eq. (3)) (Zhang *et al.*, 2011):

$$M_{CO_2} = M_{CO_2} in-oil + M_{CO_2} in-aquifer \quad (3)$$

where M_{CO_2} is the theoretical storage capacity of CO_2 in the combined reservoir (million ton), $M_{CO_2} in-oil$ is the theoretical storage capacity in the oil reservoir (million tonnes), and $M_{CO_2} in-aquifer$ is the theoretical storage capacity in the associated aquifer (million tonnes). As the aquifer is weak, we ignore the mass of CO_2 dissolved in aquifer and focus on the amount in oil reservoir and inject into the oil column and the main drive mechanism is compaction drive due to the continuous impermeable layer at the base Sherwood. The theoretical storage capacity in oil reservoirs can be calculated by the following Equation **(**Zhang *et al.*, 2011).

$$M_{CO_2} in-Oil = M_{displaced} + M^{oil}_{dissolution-in-oil} + M^{oil}_{disolution-in-water} + M^{oil}_{mineral} \quad (4)$$

The composition of CO_2 is 0.17% of the hydrocarbon component and there is CO_2 initially in place. CO_2 will be produced with the oil during primary and secondary production. The above equation can be modified by adding the amount of CO_2 present at the start of CO_2 injection.

$$M_{CO_2} in-Oil = M_{CO_2 present} + (M_{displaced} + M^{oil}_{dissolution-in-oil} + M^{oil}_{disolution-in-water} + M^{oil}_{mineral}) \quad (5)$$

$M_{CO2\text{present}}$ is the storage capacity present in the reservoir at the start of CO_2 injection. This is possible due to presence of CO_2 in the original oil composition, $M_{displaced}$ is the storage capacity provided by the voided space due to water or CO_2 flooding in the reservoir (million tonnes), in this case, the mobile CO_2 in gas phase falls under the $M_{displaced}$ which represent the fraction of CO_2 injected that will displace oil and could be trapped by impermeable barriers. $M^{oil}_{disolution-in-water}$ is the storage capacity by dissolution in formation water in the oil reservoir (million ton), $M^{oil}_{dissolution-in-oil}$ is the storage capacity by dissolution in the remaining oil of the oil reservoir (million tonnes) and $M^{oil}_{mineral}$ is the storage capacity by mineral trapping in the oil reservoir (million tonnes). These values are calculated from the compositional simulation.

Reservoir Model Description and Fluid Properties

The depth of the top of the reservoir is 1585 m . The permeability range is 0.1-1.5×10^{-12} m^2. The sand porosity is roughly 0.2 (Figure E 1). In addition, the reservoir pore volume is about 30 × 10^6 m^3 and the initial average oil saturation is 0.64 with 19 million sm^3 of oil in place. The reservoir model chosen is based on the actual offshore section of the Wytch Farm producing field containing 20×18× 40 grid blocks with 14,380 active cells. The x and y dimensions of each grid block are 180m. The model is divided into 5 layers vertically with facies distribution from top to bottom as a result of the depositional environment (Figure 3). The model was chosen instead of the full field model because of the time constraint in running the full model. The model rock characterization is based on well log data and history matched analysis made in imperial college with the permission of the British Petroleum.

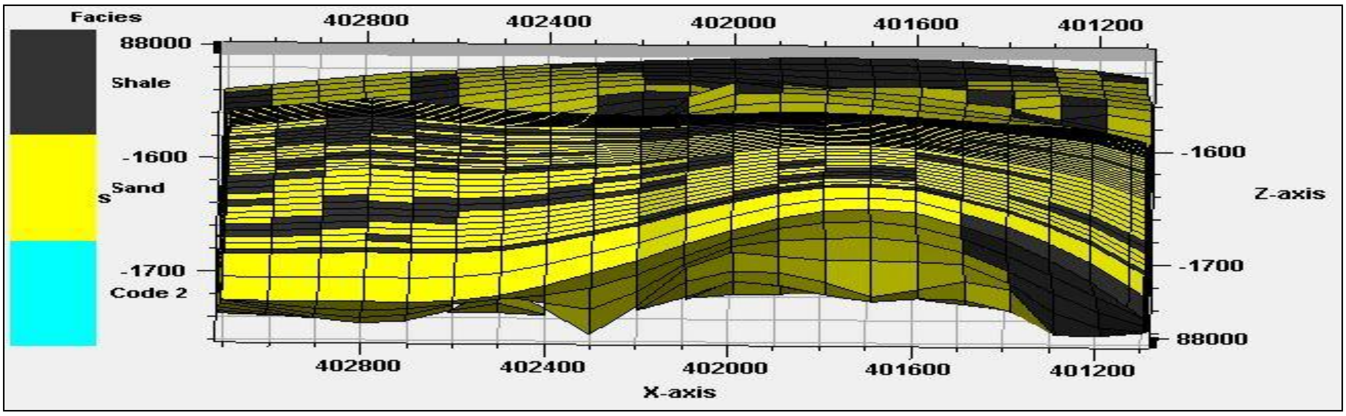

Figure 3: The side view presentation of the facies of the model indicating heterogeneity.

The boundary conditions for the model are the faults at the edges, the anticlinal structure, and the continuous shale at the base of the Sherwood sandstone and the water bottom at the base of the model as shown in Figure 3. Hence, it is a fully enclosed system (Figure E 3). The oil- water relative permeability data used was generated using Corey exponents based on the rock quality index (Figure 4) of core plugs. For simplicity, capillary pressure between oil, water and gas phases are taken as 0.

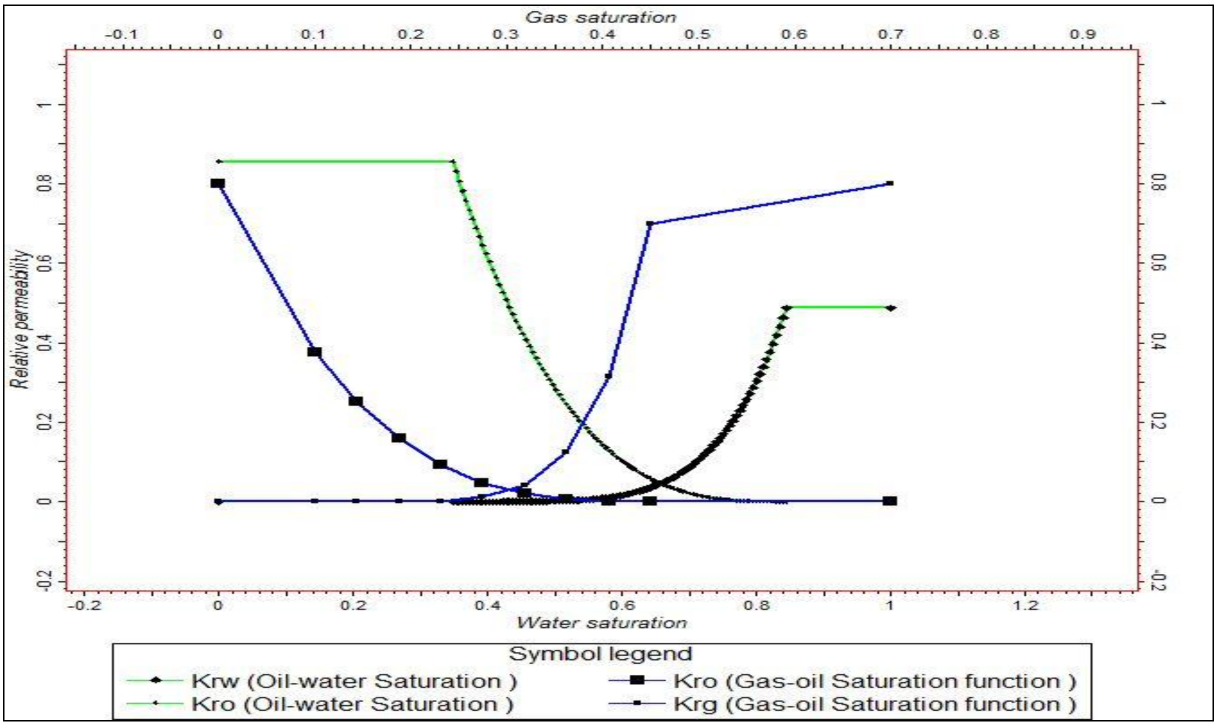

Figure 4: The oil-water and gas-oil relative permeabilities.

Table1 shows the initial composition description of the reservoir fluid and descrition of the rock properties. It is a moderately heavy (39 ^{o} API, 886 kg/m$^{3)}$ crude oil.

Table 1: Initial oil composition and the reservoir rock properties.

Initial fluid composition			
Component	Mole fraction	Frac of C7+	MW
CO_2	0.0017		
N_2	0.0267		
C1	0.1472		
C2	0.0706		
C3	0.1004		
IC4	0.0256		
NC4	0.0692		
IC5	0.0294		
NC5	0.0385		
C6	0.0529		
C7	0.0617	0.14098193	14.09319
C8	0.0672	0.15348475	17.49840
C9	0.0489	0.11169484	14.29694
C10	0.0378	0.08634079	12.26039
C11	0.0258	0.05915943	9.282887
C12+	0.1963	0.44837825	195.4929

Molecular weight of C12+ in reservoir fluid= 436kmol/kg
Specific gravity of C12+ in stock tank = 0.886
Molecular weight of reservoir fluid= 139.8kmol/kg

Reservoir description	
Property	Value
Porosity	20%
Permeability	100mD
Depth	1585m
Thickness	30m
Salinity	35,000 mg/l
Temperature	50^{o}C
Pressure (datum depth 1585m)	(168 bar)
Model Size	20 × 18 × 40
Grid block sizes	180m × 180 m
Rock Compressibility, Cr	0.0003 bar^{-1}

Reservoir model	
Depth, m	1585
Oil API gravity	39
Oil viscosity, cp	0.34
Oil saturation,%	0.36

Methodology

Screening criteria

Reservoir depth, reservoir pressure oil density, reservoir temperature and oil composition were the screening criteria used to determine the possibility for CO_2 flooding for the reservoir. These values were used to determine the miscibity pressure for conducting CO_2-EOR. It has been recognized that not all oil reservoirs are suitable for CO_2 EOR. Zhao, (2001) presented screening criteria (Table 1) which considers various characteristics of oil fields in terms of miscible gas flooding for EOR.

Table 2: Screening criteria for CO_2 flooding.

Reservoir Parameters	Range
Depth, m	>762
Oil API gravity	>22
Oil viscosity, mPa.s	<10
Remaining Oil saturation, %	>20

The comparsion of Table 2 with Table 1 shows that the Wytch Farm reservoir is a candidate for the CO_2 – EOR process. The boundary conditions of cap rock, faults and bottom water body-aquifer are also present to make the model a structurally realistic field. Pure CO_2 and the reservoir fluid are not miscible at the reservoir pressure. The minimum miscible pressure (MMP) of pure CO_2 is estimated to be in excess of 270 bars using the Cronquist correlation (Mungan, 1981). This determines MMP based on reservoir temperature (T,^{o}K) and molecular weight of the heavier fractions (MW C5+) of the reservoir oil, without considering the mole fraction of methane with the assumption that most of the methane would have been produced during primary recovery (Figure C 2). The Cronquist correlation is stated below:

$$MMP = 15.988 \times T^{(0.744206+0.001038 \times MWC5+)} \tag{6}$$

The initial pressure of the reservoir is 168 bars at a datum depth of 1585m. Miscible injection can be achieved with addition of solvent into the gas stream during gas flooding for Minimum Miscibility Enrichment,MME and injecting either pure CO_2 or solvent at pressure above MMP. Solvent is usually designed to develop miscibility. The injection pressure is calculated such that it is expected to be more than the MMP for miscible gas injection but less than the fracture pressure. At cases where injection pressure is lower than MMP, there would be immiscible gas injection. The miscibility pressure of 270 bars is taken.

Injection scenarios

The main goal is to find injection scenarios leading to maximum oil recovey and maximum storage of CO_2 in the reservoir. To achieve this goal, reservoir flow simulation was performed in Eclipse™ 300, a fully compositional three dimensional finite-difference reservoir simulator with PETREL™ RE 2010 to visualize the model in three dimensions. The code for a WAG case is found in Appendix D. For ease of simulation, eleven components were used for tuning and regression of the PVT properties using a three-parameter Peng Robinson equation of state to give the resulting compositional description of the fluid model with the variables (critical pressure, critical temperature, critical compressibility factor, and volume shift). As shown in Table 3 and Appendix E.

Table 3: Summary of component properties and Peng-Robinson parameters used to describe the fluid model.

Comp.	Mol. Weight	Critical pres. (bar)	Critical Temp (K)	Critical z- factor	Critical Volume (m^3/kg-mole)	Omega A	Omega B	Acentric Factor	Volume Shift
CO_2	44.010	74	304.26	0.27408	0.0940	0.45723553	0.007796074	0.2250	-0.06956031
N_2	28.013	34	126.48	0.29115	0.0900	0.45723553	0.007796074	0.0400	-0.18058376
C1	16.043	45	190.92	0.28473	0.0980	0.45723553	0.007796074	0.0130	-0.16160171
C2	30.070	49	305.37	0.28463	0.1479	0.45723553	0.007796074	0.0986	-0.12529310
C3	44.097	43	369.26	0.27748	0.2000	0.45723553	0.007796074	0.1524	-0.69866000
IC4	58.124	36	407.59	0.28274	0.2630	0.45723553	0.007796074	0.1848	-0.02734491
NC4	58.124	38	424.84	0.27386	0.2550	0.45723553	0.007796074	0.2010	-0.04196900
IC5	72.151	33	460.40	0.26823	0.3080	0.45723553	0.007796074	0.2223	-005700060
NC5	72.151	34	469.60	0.26884	0.3110	0.45723553	0.007796074	0.2539	-0.03891151
C6	84.000	33	512.00	0.27537	0.3510	0.45723553	0.007796074	0.2500	-0.01463601
C7+	218.000	17	744.92	0.23425	0.8499	0.45723553	0.007796074	0.70397	0.13459234

This also gave the relative volume and liquid viscosity of the constant compostion expansion experiment in Figure 4 and resulting phase behavior in Figure 5.

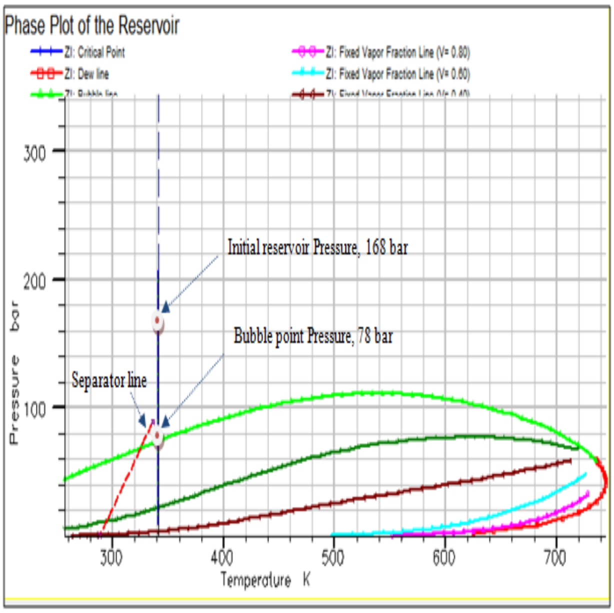

Figure 5: Plot of phase behavior.

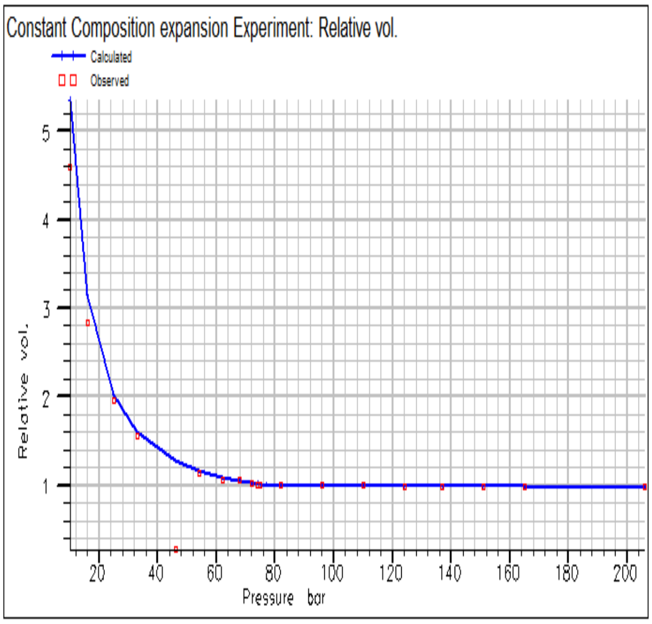

Figure 6: Plot of constant composition expansion for relative volume.

The injection schemes that are tested with composition of the injection stream in Table 5 include:

- Gas Injection after waterflooding (GAW) : Both for Pure CO_2 (injection pressure of 310 bar which is above MMP) and solvent- CO_2 at a pressure of 190 bar which is below MMP but higher than the bubble point pressure of 78 bar
- Water alternating Gas drive (WAG) after waterflooding: Both for Pure CO_2 and solvent- CO_2
- Gas injection with nitrogen content (plus 20% N_2 added to the 80 % CO_2)

Table 4: The composition of the oil and injection stream.

Component	Reservoir oil	Pure CO_2 stream	Solvent	Contaminated stream
CO_2	0.0017	1.0000	0.9000	0.8000
N_2	0.0267	0.0000	0.0000	0.2000
CH4	0.1472	0.0000	0.0500	0.0000
C2	0.0706	0.0000	0.0500	0.0000
C3	0.1004	0.0000	0.0000	0.0000
IC4	0.0256	0.0000	0.0000	0.0000
NC4	0.0692	0.0000	0.0000	0.0000
IC5	0.0294	0.0000	0.0000	0.0000
NC5	0.0385	0.0000	0.0000	0.0000
C6	0.0529	0.0000	0.0000	0.0000
C7+	0.4377	0.0000	0.0000	0.0000

The developmental strategies consist of four producing wells, one water injection well and one gas injection well (Figure 6). All wells are vertical wells. The strategies involve injection into the reservoir oil column for the CO_2 to be in contact with the oil phase. The process is monitored for the influx of bottom water aquifer which during production. Gas injection begins after 7000 days of water flooding. The water injection helps to maintain reservoir pressure while the post- water flooding gas injection performs incremental recovery and storage.

Pure 100% CO_2 injection is taken as the reference case. Gas is injected at a rate of 4,500 m^3day and water is injected at a rate of 3000m^3/day. Injection pressure of 310 bars was less than the fracture pressure for the pure CO_2 case while the solvent cases have injection pressures less than 270 bar but higher than the bubble point of 78 bar. The size of the initial water injection was 0.1 pore volume. The WAG case injects water and CO_2 in alternating slugs. The water would help to reduce the mobility of CO_2 within the reservoir to ensure effective displacement, reducing the risk of leakage of mobile CO_2 to the surface and possibly delay CO_2 breakthrough. Because of the effect of gravity, the gas displaces the oil in the upper part of the Sherwood reservoir and the water invades the lower parts. The combined effect is expected to improve the field sweep efficiency for higher recovery. Here, the alternating injection strategy is 100 days of water injection and 30 days of gas injection with water as the first injection fluid with different 0.45 optimal WAG ratio involving volumes of water and gas. The simulation stops after 12,000 days.

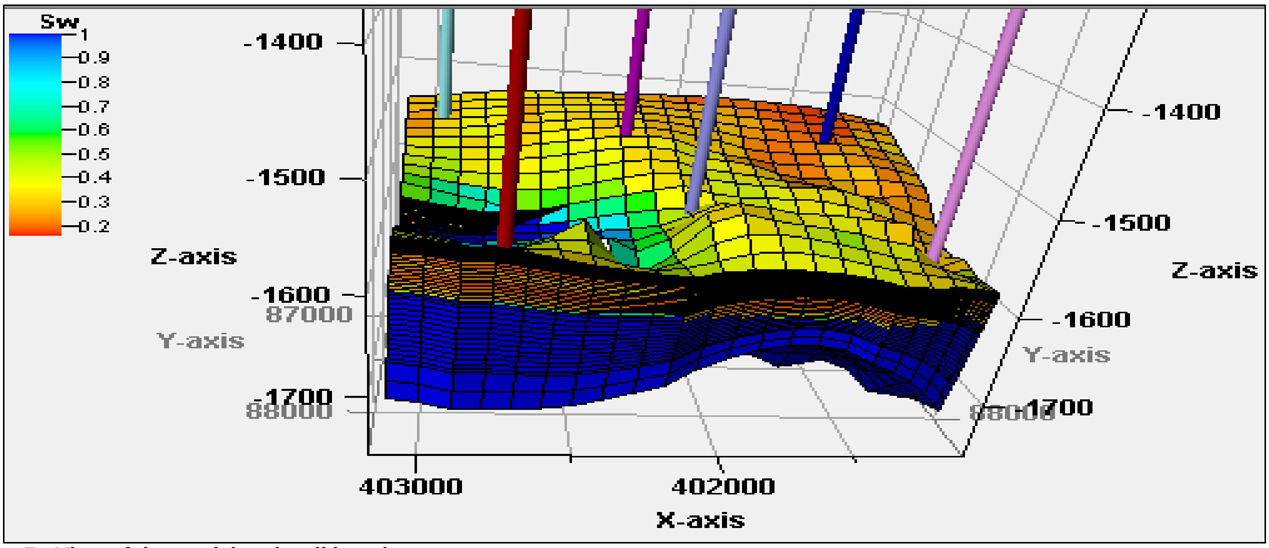

Figure 7: View of the model and well locations.

In the simulations, the water injector is controlled by injection surface rate while the CO_2 injector is controlled by the reservoir rate due to the reduction in the CO_2 volume with depth as a supercritical fluid (Figure 1) and the producers are controlled by bottom-hole pressure.

Results and Discussion

Figure 10 shows plot of the CO_2 storage potential in all phases for the base case. CO_2 in place reduces as production starts. Storage by dissolution as CO_2 is dissolved in water is the least in quantity of about **8 %** of the injected gas but it is the safest means of storage. The salinity of the formation water contributes to the dissolution of the injected CO_2. It is also observed that aquifer support is low due to the continuous shale at the base of the reservoir model. The CO_2 dissolved in remaining oil of about **23%** to cause the swelling effect which is the main reason for incremental recovery.

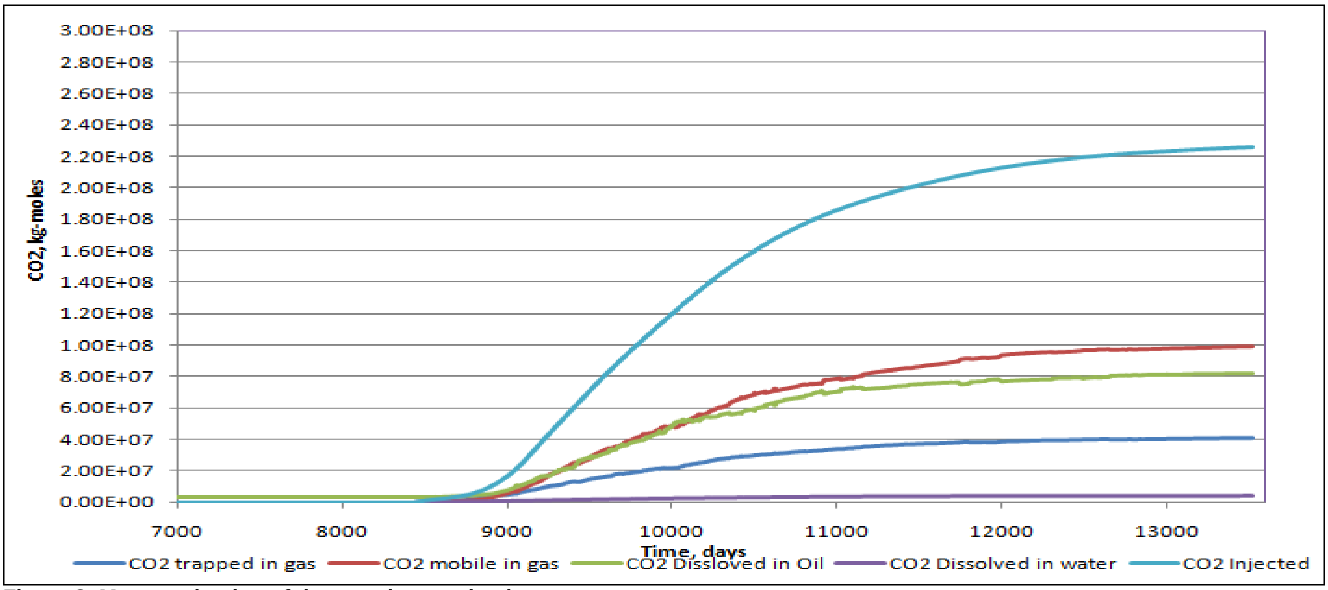

Figure 8: Mass evaluation of the trapping mechanisms.

A certain amount of this fraction will be part of CO_2 production during CO_2 breakthrough. A large amount of CO_2 trapped as gas of about **25%** of the injected gas by the replacement of the void spaces created due to the displacement of oil by water and CO_2 flooding. It is believed that the trapping mechanism that has kept the oil in place for millions of years will keep the mobile CO_2 in the reservoir. The largest amount of CO_2 injected is found to be mobile. The cap rock, low permeability zones and fault acts as boundary conditions for structural trapping to trap the CO_2 as shown in Figure 9 where CO_2 saturation increases over time. This has the biggest storage potential but also the largest uncertainty. No mineralization at this time because it takes thousands and millions of years for CO_2 to form minerals with the reservoir rock and therefore no storage due to mineralization as supported by IPCC report of 2005 (Figure C 1). CO_2 may react with caprock. At such case, storage by capillary trapping would be the safest. WAG process would help to achieve this.

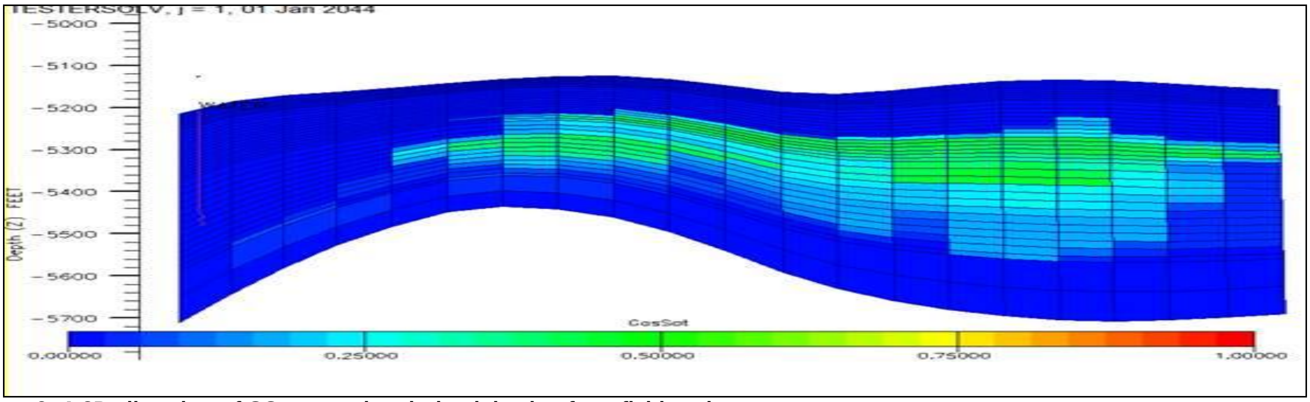

Figure 9: A 2D slice view of CO_2 saturation during injection from field scale.

Figure 12 summaries the performance of the injection strategies outlined above. For ease of interpretation, 3 cases are presented and numerous simulations were run to ensure generality.

The incremental recovery is obvious in all the injection cases due to the miscible flooding. The 100% pure CO_2 injection after 7,000 days of waterflooding is taken as the base case with 0.7 pore volume. All the CO_2-solvent cases have better cumulative production. The solvent cases do not require high pressure to achieve impressive incremental recovery but the pure CO_2 injection requires high pressure for miscibility to take effect. The choice of CO_2-solvent injection depends on the availability of the hydrocarbon fraction of the produced oil. The pure injection with pressure higher than MMP will require high cost of injection while the solvent injection will require the cost of the C1 and C2 component in the injection stream. The MMP will ensure that CO_2 is miscible with the oil while the solvent will enrich the oil in the reservoir for miscibility. The recovery of the pure CO_2 injection is limited to the injection pressure, though above MMP but not higher than the fracture pressure of the reservoir. The recovery is greatest for WAG with solvent reaching cumulative oil of about 14 million cubic metres produced. CO_2 breakthrough of the pure CO_2 injection starts at about 8,300 days while that of the solvent CO_2 took 8,500 days. The WAG cases did not experience breakthrough even at 12,000 days. This indicates that with miscibility and good well control, there is impressive displacement efficiency with delayed breakthrough of CO_2. The mechanism of WAG cases deployed both swelling effect of oil, displacement of oil by the oil and the capillary trapping of the CO_2 injected by the chase brine. The well control involves well placement and optimum injection pressure which reduces the re-cycling of the injected gas and improves the contact of the solvent with the reservoir fluid.

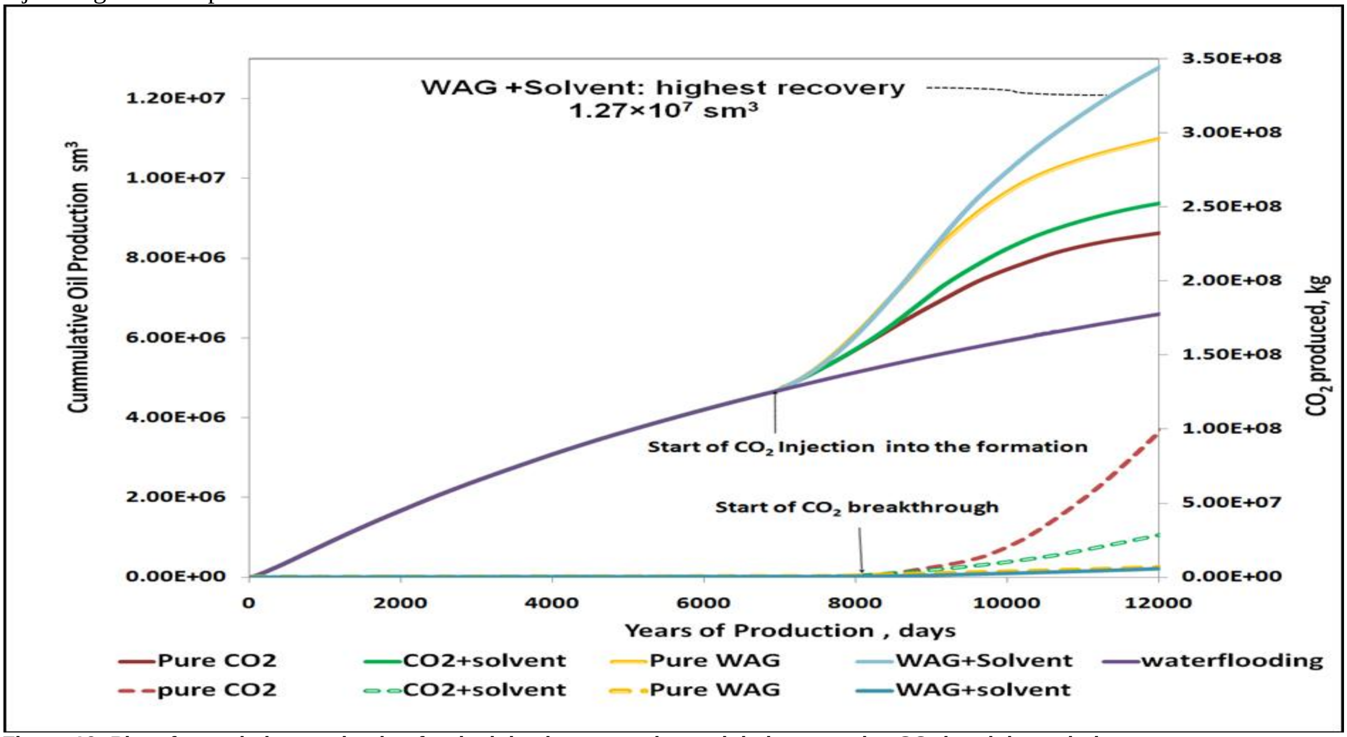

Figure 10: Plot of cumulative production for the injection strategies and their respective CO_2 breakthrough times.

Figure 13 illustrates the effect of nitrogen, N_2 in the injection stream in comparison with pure CO_2 injection. The injection of 80% CO_2 with 20% of N_2 has lower cumulative oil production of 8.60×10^6sm^3 compared to 9.20×10^6sm^3 after 12,000days of the pure CO_2 injection. N_2 reduces the amount of CO_2 concentration in the stream and also the amount of CO_2 dissolved in oil which reduces the dissolution of CO_2 in oil to cause swelling effect.

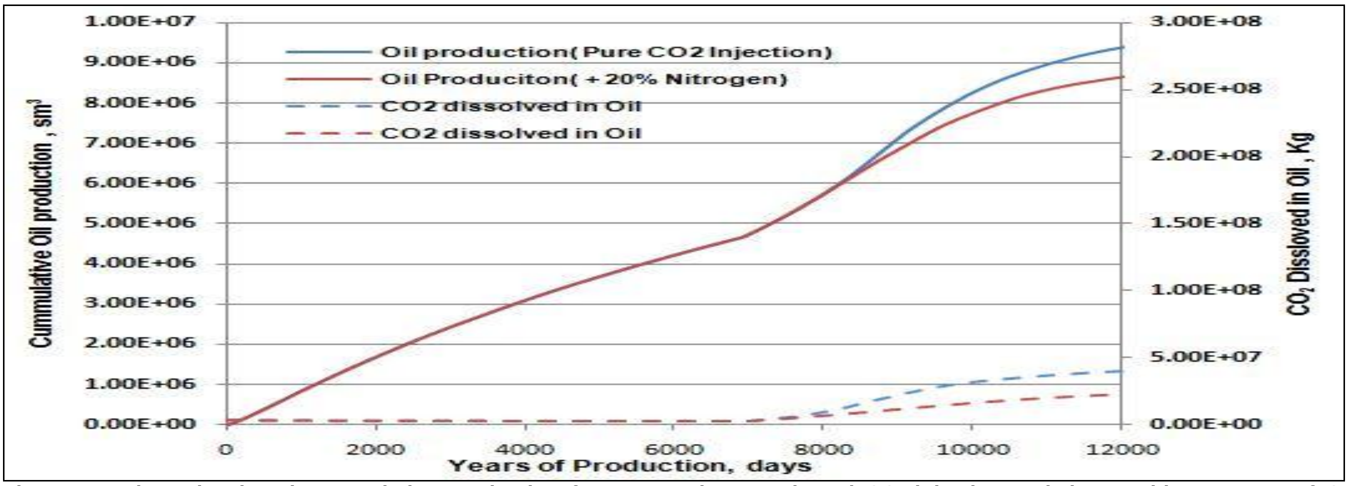

Figure 11: Plots showing the cumulative production for pure and contaminated CO_2 injection and the resulting amount of CO_2 dissolved in oil.

Storage studies

The CO_2 trapping mechanisms in all phases have been considered for the strategies under study. It is observed that the cumulative CO_2 dissolved in water is highest for the WAG case (Figure 14) because of the ability of the water to act as chase brine to trap mobile CO_2 which is in agreement with Qi *et al* (2008). WAG is a possible scheme for CO_2 Enhance Oil Recovery and Sequestration for the reservoir due it high contribution to capillary trapping. It is possible N_2 reduces the dissolution of CO_2 in water.

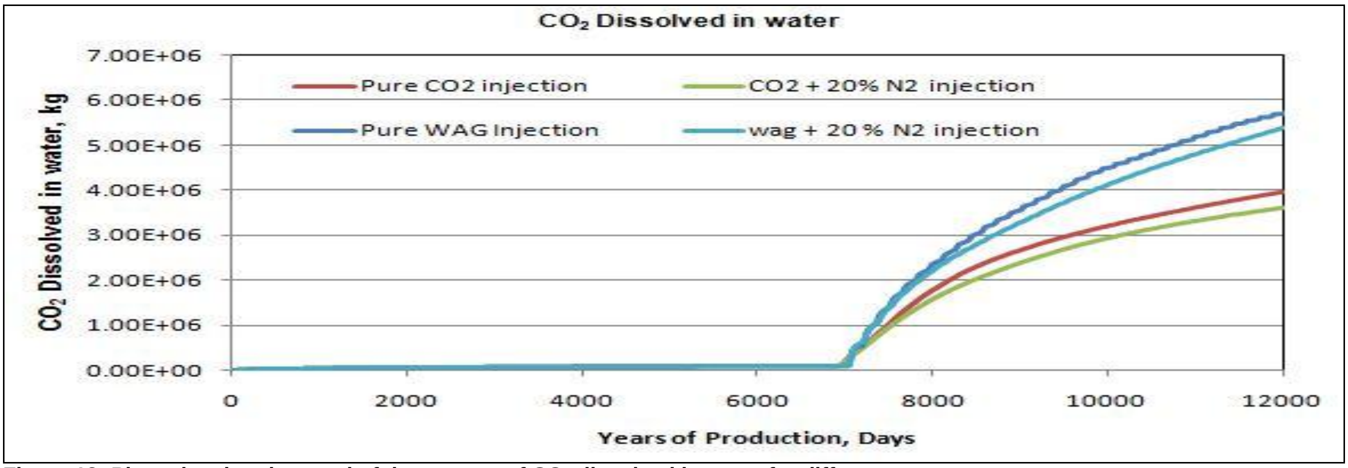

Figure 12: Plots showing the trend of the amount of CO_2 dissolved in water for different cases.

The trapped or immobile gas in Figure 13 is highest in WAG case as the alternating slug process provides void spaces for CO_2 to fill. However the other WAG case with 0.45 WAG ratio illustrates where we have low trapped gas because the water injection rate is high and the water has filled most of the space where CO_2 would have been filled. This process reduces sequestration.

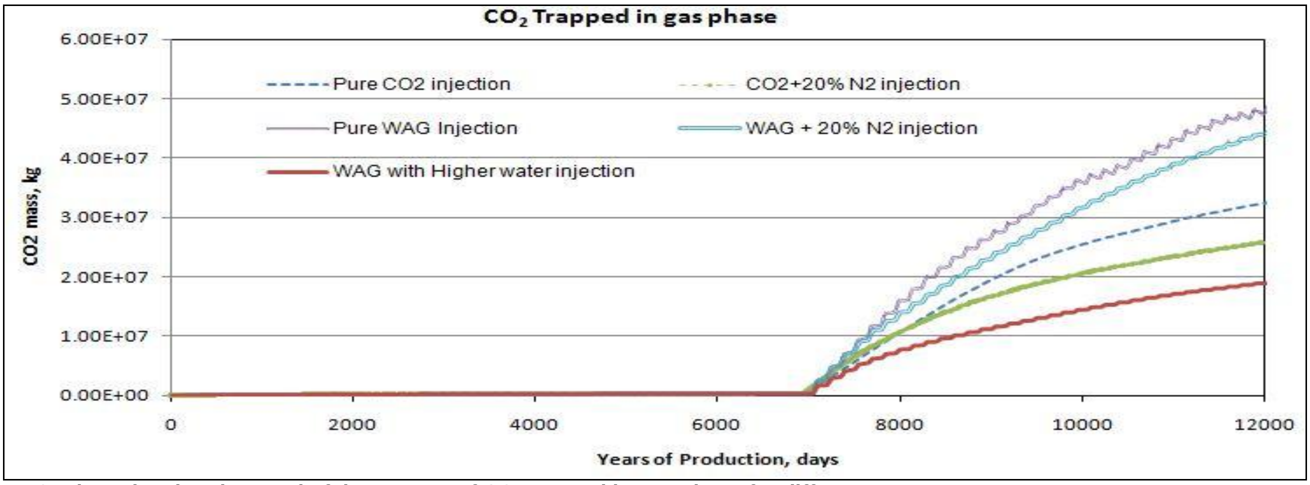

Figure 13: Plots showing the trend of the amount of CO_2 trapped in gas phase for different cases.

The mobile gas has the big question on storage security of CO_2. The WAG case is least in amount because of the alternating slug injection processes. The pure CO_2 case has the highest mobile CO_2 since there are no other components in the injection stream (Figure 14).

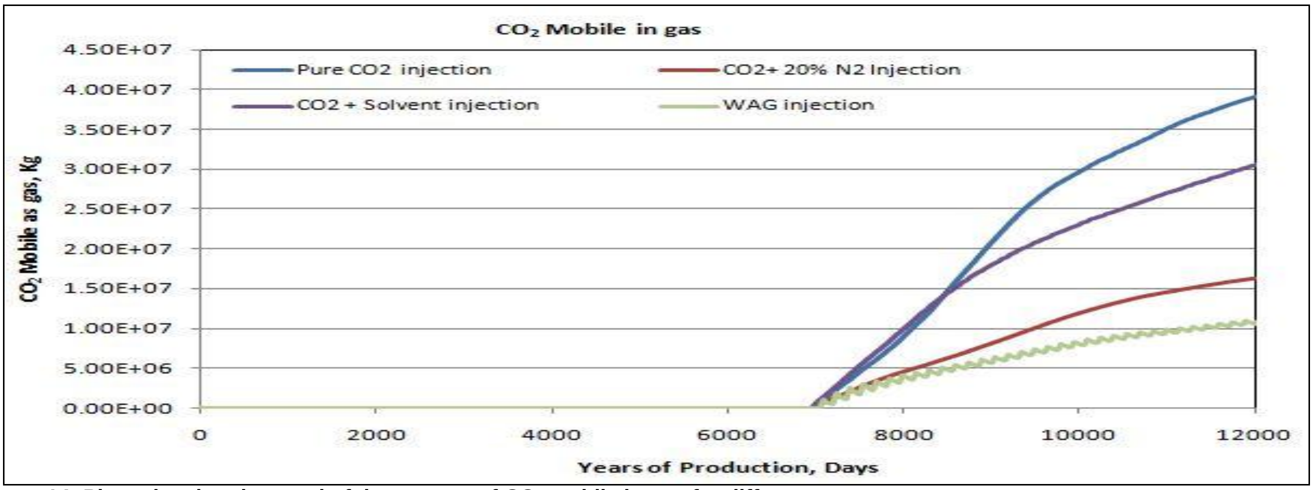

Figure 14: Plots showing the trend of the amount of CO_2 mobile in gas for different cases.

Figure 15 accounts for the amount of CO_2 dissolved in oil phase with the same injection condition but now with higher injection pressure of 270 bars for the pure CO_2 injection case. It is observed that higher pressure gives higher dissolution of CO_2 in the oil phase. The trend of CO_2 reduction during production and the increase in CO_2 in the reservoir as injection starts is also observed. This dissolution in oil swells the oil to improve recovery but also contribute to CO_2 re-cyling in the pure CO_2 Injection case.

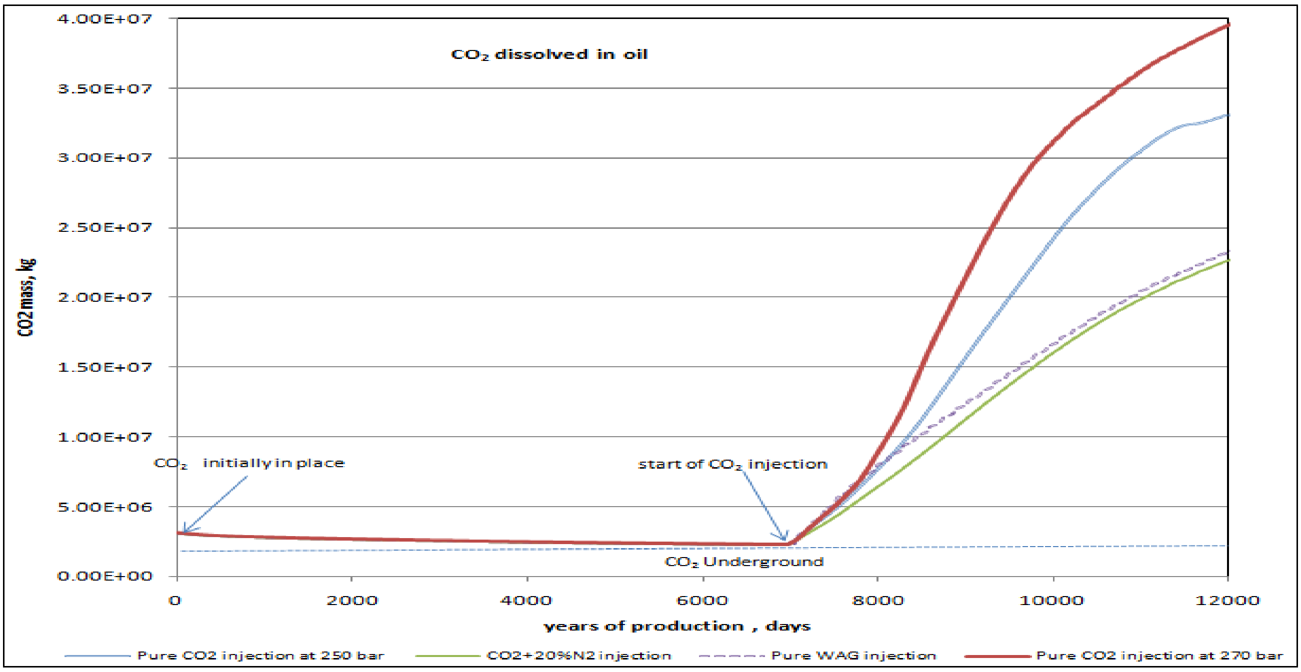

Figure 15: Plots showing the trend of the amount of CO_2 dissolved in oil for different cases.

Figure16 illustrates the overall storage capacities for the different injection strategies. The broken lines indicate CO_2 storage and the continuous lines indicate cumulative production. The pure CO_2 injection strategies perform better than the miscible solvent injection because of the fraction of the CO_2 that is made up of other components in the continuous injection. This is because the highest form of storage mechanism for this period is mobile gas for structural trapping which also has the highest risk of leakage as shown in Figure 10. The figure also suggests that injection for mobility control could lower sequestration as indicated for the CO_2-Solvent cases and WAG because of rapid process of capillary trapping which is the safest means of storage though high improve in recovery could occur as shown in Figure 10. The WAG processes sequester less than half the CO_2 as does pure CO_2 or CO_2-solvent injection with or without well control in the field scale provided but has highest oil recovery.

Table 5: Evaluation of storage capacities for the injection strategies after 12,000 days.

Strategies for CO_2 Injection	Amount injected (10^6)kg	Amount produced(10^6)kg	Amount stored(10^6)kg	Water cut	HCPV	Storage efficiency (%)
Continuous Gas Injection	130	47	88	0.8	0.1	67
Continuous Gas Injection with Nitrogen	85	28	57	0.8	0.1	65
0.45WAG ratio	59	6.6	52	0.8	0.1	88

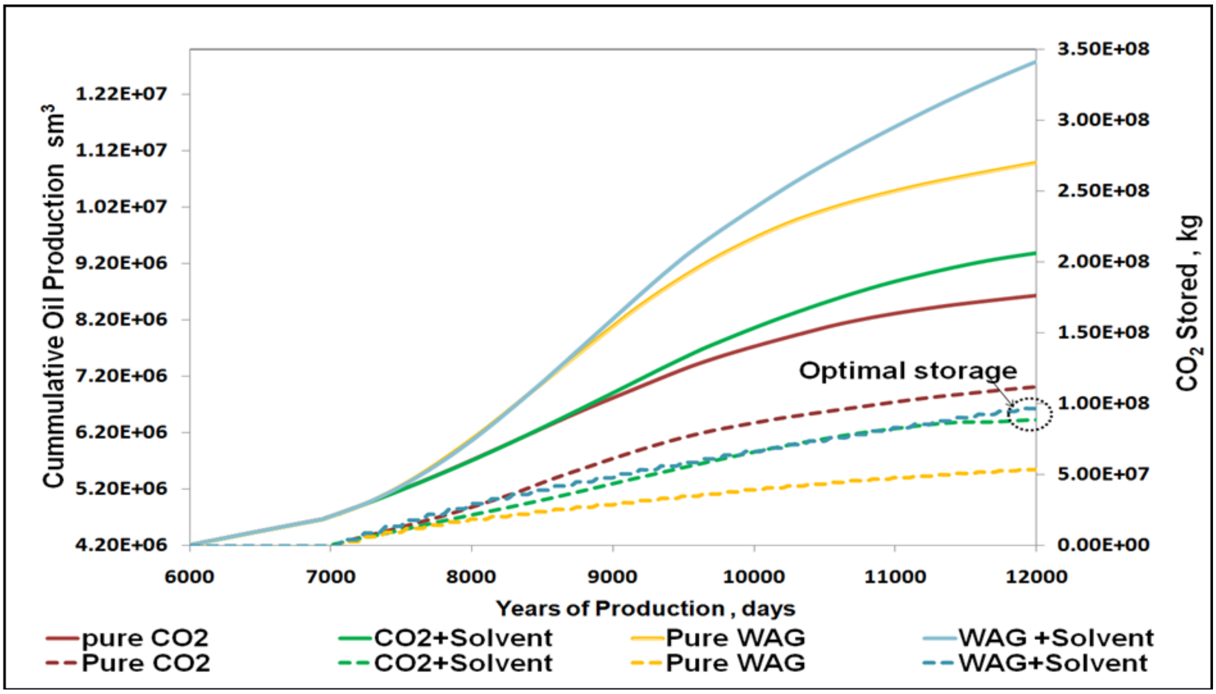

Figure 16: Plots showing the cumulative production and CO_2 stored for all cases.

Pore spaces are filled with water that could otherwise be filled with CO_2 for the WAG case. Table 5 summaries the optimal storage capacities for the injection cases and their storage efiiciencies.

For a target of injecting a total of 12×10^9sm^3/day of CO_2 for storage for 5,000 days as indicated in Table 6 below with the injections pressures above and below MMP of 270 bar. The optimum WAG case injects CO_2 at $1{,}500\times10^3$sm^3/day during the alternating injection while the continuous CO_2 injection injection with 790×10^3sm^3/day while for the contaminated stream injects 820×10^3sm^3/day with the water injection of 1,300sm^3/day to maintain pressure. The WAG process of injection performs better than the continous CO_2 injection for storage. This is mainly due to capillary trapping during the shift from water injection and the evidence of lowest breakthrough (Figure 17). This reduces the uncertainity of leakage of the caprock later when injection stops and abandonment of the field. The contaminated N_2 reduces the amount of CO_2 to be stored in the reservoir. For the purpose of recovery and storage, rapid capillary trapping of the CO_2 using WAG process is preferable compared to the continuous CO_2 injection.

Table 6: Strategies table for storage of CO_2 with the same storage amount target.

Target amount to be injected=12×10^9sm³/day (170,000,000 kg) MMP=270 bar					
Date	Strategies	Pure CO_2	CO_2+N_2	WAG Strategies	Start of WAG CO_2 injection (2030)
2011					
	voidage	0.81	0.81	First fluid for injection	Water
	Well rate prod. Control (sm^3/d)	3,900	3,900	WAG cycle frequency	Days
	well water inj. Control (sm^3/d)	1,500	1,500	Water injection period	100
	well water cut	0.8	0.8	Gas injection period	50
2030	Start of CO_2 injection			Water control mode	surface rate
	Well rate prod. Control(sm^3/d)	4,200	4,200	Surface water rate (sm^3/d)	1,500
	well pressure prod control(bar)	275	82	Surface gas rate (10^3 sm^3/d)	2,500
	well gas inj. Control(bar)	310	240	Water bottom hole pressure [bar]	275
	Well gas injection rate (10^3 sm^3/d)	790	820	Gas bottom hole pressure (bar)	310
	Well water injection rate (10^3 sm^3/d)	1,500	1,500	well water inj. Control (sm^3/d)	1,300
	well water inj. Control (bar)	345	242		
2044	Amount of CO_2 produced (kg)	58,000,000	30,000,000		10,000,000
	Amount of CO_2 stored (kg)	112,000,000	140,000,000		160,000,000

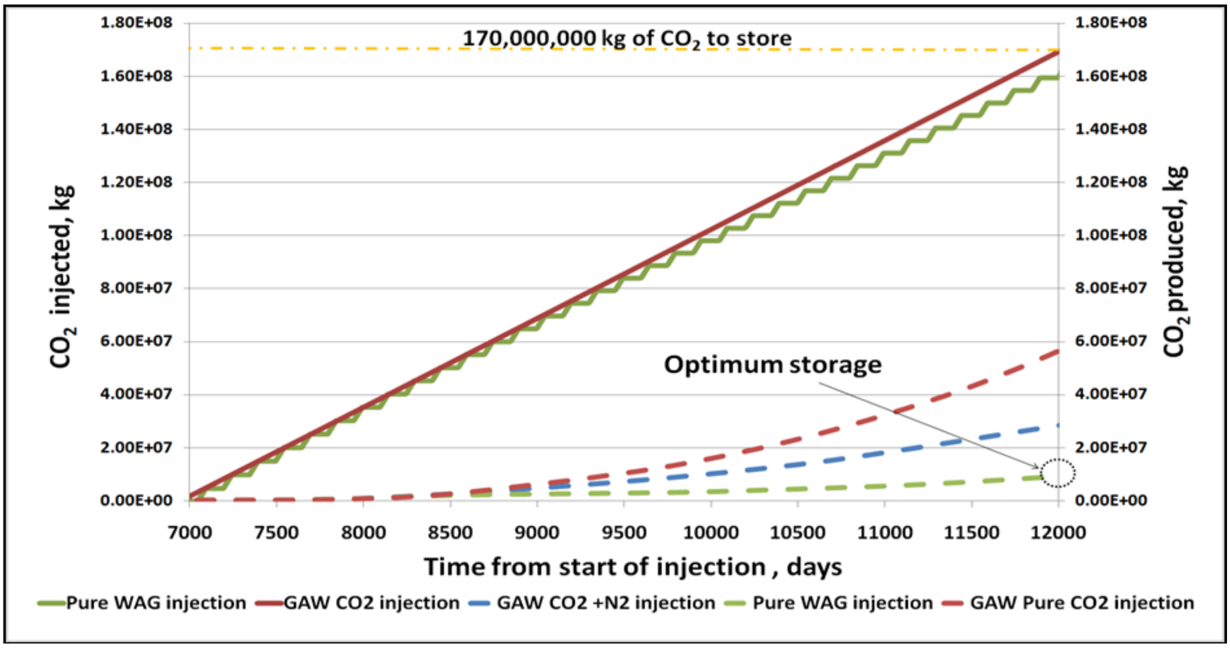

Figure 17: Amount of CO_2 trapped for the designed of same amount of CO_2 for storage for the WAG and GAW cases.

Conclusions

CO_2 storage and Enhanced Oil Recovery is a possibility for the Wytch Farm oil field. The hydrocarbon reservoir optimum recovery and storage of CO_2 which demands the maximum incremental recovery and maximum emplacement of CO_2 can be achieved based on the degree of the objective function. WAG strategy for this study indicated maximum recovery with good storage efficiency for rapid trapping of CO_2 injected reducing the uncertainty of mobile CO_2 in the reservoir and CO_2 production is the best way to illustrate the amount of CO_2 stored for every one barrel of oil produced. The continuous CO_2 injection could store more of its CO_2 as mobile gas and increase the risk of leakage to the surface.

It was also observed that the presence of nitrogen as a contaminant reduces the miscibility of CO_2 in oil which could affect recovery. This is because CO_2 recovery depends on the oil composition with CO_2 injection stream. The continuous flooding after water injection requires re-cycling cost due early breakthrough and to high amount of CO_2 injection. WAG process could give little or no CO_2 breakthrough. The mass evaluation of the CO_2 storage implemented helps to quantify the amount of CO_2 sequestered better due to the complex volumetric behavior of the CO_2 in the reservoir with temperature and pressure. For the same amount of CO_2 for storage, the WAG process is the most desirable.

Further work can be carried out on the geology of the formation to account for the storage security while considering uncertainties in the model parameters. Thermal flooding with CO_2 injection can also be studied in the future on this field for enhance oil recovery. Other areas for further research are the carbon tax on emission and crude oil price to help determine the best injection strategy to implement.

Acknowledgements

I would like to express my gratitude to my advisor, Professor Martin Blunt, for his invaluable support, encouragement, supervision and useful suggestions throughout the research work. I am also extremely thankful to my mother Mrs Helen Eteimua Oseme for her encouragement during difficult times of the project period. Furthermore, I would like to thank SPDC Nigeria for sponsoring my MSc course at Imperial College, London. God bless you all.

Nomenclature

k = permeability, m^2 [Darcy]
k_{rg} = relative permeability of gas, dimensionless
k_{ro} = relative permeability of oil, dimensionless
k_{rw} = relative permeability of water, dimensionless
MW = molecular weight
ϕ = porosity, fraction
S_w = water saturation, fraction
T = temperature, K (Kelvin)
V = block pore volume, m^3
V_{inj} = volume of water injected
V_{pw} = volume of water produced
R_f = recovery factor
A = area, m^2
h = reservoir thickness
m = mass, kg

Superscripts

Inj = injection of water
pw = produced water
CO_2 = carbon dioxide

Acronyms

CCS = carbon capture and storage
CO2CRC= cooperative research centre for greenhouse gas technologies
EOR = enhanced oil recovery
GAW = gas injection after waterflooding
HCPV = hydrocarbon pore volume
MMP = minimum miscibilty pressure

MME = minimum miscibilty enrichment
SM^3 = standard cubic metres
PV = pore volume
WAG = water-alternating-gas

Conversion Factors & Units

Bbl x 0.1589873	=	Cubic Metres (m^s)
T°C+273.15	=	T (K)
Bar $\times 10^5$	=	Pascal (Pa)
Ton$\times 10^3$	=	Kilogram (kg)
Lbm/ft×16.01846	=	Kg/m^3

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Appendix

APPENDIX A: CRITICAL LITERATURE REVIEWS

SPE 59327 (2000)

CO_2 Injection in the Weyburn Field of Canada: Optimization of Enhanced Oil Recovery and Greenhouse Gas Storage with Horizontal Wells

Authors: Qamar M. Malik, SPE, and M.R. Islam, SPE, university of Regina, Saskatchewan, Canada

Contribution to the understanding of CO_2 storage and EOR

Significant because this paper demonstrated key parameters of contaminated gas stream and the use of horizontal wells for CO_2 injection for miscible CO_2 flooding in the Weyburn Field of Canada.

Objective of the paper:

To observe the contaminated gas and horizontal wells as key parameters controlling miscible CO_2 flooding

Methodology used:

A series of simulations of post- waterflooding, post primary – CO_2 injection schemes were performed with pure and contaminated gas stream using a fully compositional model for a reservoir with and without bottom waters (aquifers).

Conclusion reached:

1. Nitrogen contamination in the gas stream has an impact in the tertiary recovery. The presence of contaminants decreases the solubility and diffusivity of CO_2 into oil subsequently leading to reduction in swelling of oil by carbon dioxide.
2. The size of bottom waters has significant impact on the oil production and CO_2 storage capacity.

Comment:

Horizontal wells were observed during the simulation for a real reservoir model and edge water drive was not considered.

Energy Conversion and Management 46 1941-1956 (2005)

Geological storage of carbon dioxide and Enhance oil recovery. II. Cooptimization of storage and recovery

Aurthors: A.R Kovscek, M.D Cakici

Contribution to the understanding of CO_2 storage and EOR

Important, because the boundary condition such as aquifer are considered. Conditions for miscible and immiscible gas injection were also considered.

Objective of the paper:

To develop carbon dioxide injection strategies leading to cooptimization of CO_2 storage and oil recovery for a given three dimensional reservoir model using compositional simulation assuming the sequestration services provide significant revenue.

Methodology used:

Compositional modeling was performed testing variety of injection schemes with pure CO_2 and solvent gas injection. Weighting factors were considered to determine the aim of maximum recovery and maximum storage.

Conclusions reached:

1. The goal to sequester maximum carbon dioxide while maximizing oil recovery rate from an oil reservoir is largely different from the goal of oil recovery alone.
2. An effective process for cooptimzation of CO_2 sequestration and oil recovery is a kind of well control that constrains the rate of injection and production.

Comments:

The crude oil CO_2 composition is zero.

SPE 115663 (2008)

Design of Carbon Dioxide Storage in Oilfields

Authors: Ran Qi, Tara C. Laforce and Martin J. Blunt, SPE, Imperial College London.

Contribution to the understanding of CO_2 storage and EOR

This study extends the design of carbon dioxide storage in aquifers to oilfields.

Objective of the paper:

To demonstrate the effectiveness of pore-scale capillary trapping to immobilize CO_2 in oil reservoirs using analytical solutions to the transport equations, accounting for relative permeability hysteresis.

The paper studies field-scale oil production and CO_2 storage using streamline-based simulator that captures dissolution, dispersion, gravity and rate-limited reactions in three dimensions.

Methodology used:

A series of fine-grid 3D simulations of CO_2 and trapping were perfomed with varying CO_2 reservoir-volume fractional flows. CO_2 is injected after a period of waterflood at different scenarios.

Conclusion reached:

1. CO_2 storage and tertiary recovery in a heterogeneous oilfield was studies

2. To retain the CO_2 in the reservoir, an injection strategy where CO_2 and water are injected simultaneously at a higher water alternating gas WAG ratio (more water) than the optimum value was proposed

3. Where there are concerns over long-term storage security, a brief period of chase brine injection was sufficient to render more than 90% of the CO_2 underground trapped or dissolved with an overall storage efficiency of approximately 17%

Comments

International Journal of Greenhouse Gas Control 3 195 – 205 (2009)

Design of Carbon Dioxide Storage in Aquifers

Authors: Ran Qi, Tara C. Laforce and Martin J. Blunt, SPE, Imperial College London.

Contribution to the understanding of CO_2 storage and EOR

Demonstrated optimal CO_2 injection strategies by injecting CO_2 mixed with brine at reservoir volume fraction between 85-100% followed by a short period of chase brine by a process called capillary trapping. This becomes important where the top seal of geological formations could leak or have gaps or penetrated by well through which CO_2 could escape to the atmosphere.

Objective of the paper:

To design injection strategies that maximizes storage efficiencies in aquifers and minimizes the total amount of brine injected using stream-line based simulation that captures the effect if reservoir heterogeneity.

Methodology used:

A series of simulations where the amount of trapping is given by Land (1986) model is being compared with a base case.

Conclusion reached:

1. The injection of CO_2 and brine together mitigates the mobility contrast between injected and displaced fluids, leading to higher storage efficiencies than injecting CO_2 alone.

2. The chase brine renders the CO_2 trapped and relatively short period of injection is sufficient to trap the vast majority of the CO_2. Once trapped the CO_2 may slowly dissolve or react but cannot escape.

Computational Geosciences 13: 493-509 (2009)

A three-phase four component stream-line based simulator to study carbon dioxide storage

Authors: Ran Qi, Tara C. Laforce and Martin J. Blunt

Contribution to the understanding of CO_2 storage and EOR

This paper shows the possibility of CO_2 storage in aquifer and oilfields and the dissolution of CO_2 in other phases (gas, oil and water).

Objective of the paper:

To extend an existing streamline simulator (Batycky et al., SPE Reservoir Engineering 12 (4): 246-254, (1997) that considered two phases (aqueous and hydrocarbon) and two components (water and oil) to handle three-phase (aqueous, hydrocarbon, and solid), four component (water, oil, CO_2, and salt) transport applied to CO_2 injection.

Methodology used:

Simulations were conducted on a North Sea reservoir description. Design of CO_2 injection strategies in aquifers to maximize CO_2 storage and in oil reservoirs to optimize both CO_2 storage and oil recovery was conducted.

Conclusion reached:

1. The solution of CO_2 transport in aquifers and oilfields was verified by comparing one- dimensional numerical simulation with analytical solutions.
2. A carbon storage strategy where CO_2 and brine injection alone, which can trap the majority of the CO_2 in residual phase was proposed.

SPE 132795 (2010)

Optimizing Oil Recovery and Carbon Dioxide Storage in Heavy Oil Reservoir

Authors: L. Sobers, Tara C. Laforce and Martin J. Blunt

Contribution to the understanding of CO_2 storage and EOR

This paper shows the possibility of CO_2 injection into heavy oil reservoirs which involve significant recycling of injected with as much of the CO_2 injected being emplaced underground.

Objective of the paper:

To study the design of enhanced oil recovery in heavy oil reservoirs combined with CO_2 storage using field-scale reservoir simulation.

Methodology used:

Injection into heavy oil reservoirs through the mechanisms of crude viscosity reduction, oil welling and immiscible gas drive was adopted with tuning a three-parameter Peng-Robinson equation of state to match measured PVT data

Conclusion reached:

1. This study indicated that satisfactory enhanced heavy oil recovery and carbon storage may be achieved simultaneously.
2. Successive WAG cycles allow for greater capillary trapping, at the same time oil viscosity decreases as more carbon dissolves into the crude.

Comment

The reservoir description is a section of homogenous unconsolidated sand and thermal flooding with CO_2 injection was not considered.

SPE 133594 (2010)

Optimization of Carbon Dioxide Sequestration and Enhanced Oil Recovery in Oil Reservoir

Aurthors: Hamid Reza Jahangiri, Dongxiao Zhang

Contribution to the understanding of CO_2 storage and EOR

Significant, because this paper utilizes compositional simulation and determines the storage potential and incremental recovery of the reservoir model.

Objective of the paper:

To develop carbon dioxide injection strategies leading to cooptimization of CO_2 storage and oil recovery for a given three dimensional reservoir model using compositional simulation

Methodology used:

Reservoir simulations were performed with ECLIPSE^{TM} 300, a fully compositional, finite difference based reservoir simulator considering continuous gas injection, gas injection after water flooding and water alternating gas drive as injection scenarios.

Conclusions reached:

1. The goal to sequester maximum carbon dioxide while maximizing oil recovery rate from an oil reservoir is largely different from the goal of oil recovery alone.
2. An effective process for cooptimzation of CO_2 sequestration and oil recovery is a kind of well control that constrains the rate of injection and production.

Comments:

The study is based on PUNQ-S3, a synthetic reservoir developed on the basis of an actual producing field using a North Sea crude oil as the reservoir fluid.

International Journal of Greenhouse Gas Control G Model IJGGC-396 (2011)

Assessment of CO_2 storage capacity in oil reservoirs associated with large lateral/underlying aquifers: Case studies from China

Authors: Liang Zhang, Sharon Ren, Bo Ren, Weidong Zhang, Qing Guo, Li Zhang

Contribution to the understanding of CO_2 storage and EOR

This paper illustrate the advantages of lower geological leakage risk associated with oil and gas traps during CO_2 injection into oil and gas reservoirs associated with large aquifers, and large storage capacity of their connected aquifers.

Objective of the paper:

This paper studies and discusses the various storage mechanisms of CO_2 in oil reservoirs and their associated saline aquifers.

Methodology used:

A calculation method for CO_2 storage capacity in the combined reservoirs was developed based on material balance for different trapping mechanisms of CO_2 for miscible flooding.

Conclusion reached:

1. A simplified material balance method to calculate the storage capacity of CO_2 in combined oil reservoirs and aquifers, which has considered various CO_2 trapping mechanisms in place, and it is useful and sufficient for primary site screening of storage projects.

2. This paper shows that associated aquifers can provide much larger storage capacity than that in oil reservoirs, and CO_2 trapping and dissolution trapping are the major contributors. In oil reservoirs alone, the storage capacity is mainly contributed by oil and water displacement, while CO_2 dissolution in remaining oil can be also significant especially when oil reservoirs have low oil recovery factor.

Comment:

The methodology of this paper is applied to five typical oil reservoirs associated with aquifers in china as case studies. The potentials of CO_2 EOR and storage deserve further detailed studies

APPENDIX B: CRITICAL MILESTONES TABLE

Paper No.	Year	Title	Authors	Contribution
DOE/MC /22042-10 (DE88001227)	1988	"Reservoir Characterization for the CO_2 Enhanced Oil Recovery Process"	Franklin M Orr, Jr., Abraham Sageev Grader	This explains the research effort to quantify non-uniform flow on displacement performance in CO_2 floods.
ISBN-0-13-281601-6	1989	"Enhanced Oil Recovery"	Larry W. Lake	Explain the fundamental and principle of CO_2 flooding
SPE 115663	2008	"Design of Carbon Dioxide Storage in Oilfields"	R. Qi, T. La Force, and M.J. Blunt	Extend study of the SPE 109905 to inject more water than optimum WAG into depleted oil and gas reservoir which leads to improve storage of CO_2 and increases the field life. The short period of chase brine injection trap most of the CO_2 remaining
IJ GGC 2009	2009	"Design of Carbon Dioxide Storage in Aquifers"	R. Qi, T. La Force, and M.J. Blunt	Demonstrated optimal the CO_2 injection strategies by injecting CO_2 mixed with brine at fractional flow between 85-100% followed by a short period of chase brine
Computational Geosciences 13:493-509	2009	"A three-phase four component streamline-based simulator to study carbon dioxide storage"	R. Qi, T. La Force, and M.J. Blunt	Extension of existing streamline simulator that has two phases and two components to handle three-phase, four component transport applied to CO_2 injection
SPE 133594	2010	"Optimization of Carbon Dioxide Sequestration and Enhanced Oil Recovery in Oil Reservoir"	Hamid Reza Jahangiri and Dongxiao Zhang	This paper discusses the effects of several injection strategies and injection timing on optimization of oil recovery and CO_2 storage capacity for a synthetic, three dimensional, heterogeneous reservoir models

APPENDIX C: CO2 STORAGE INCREASE WITH TIME

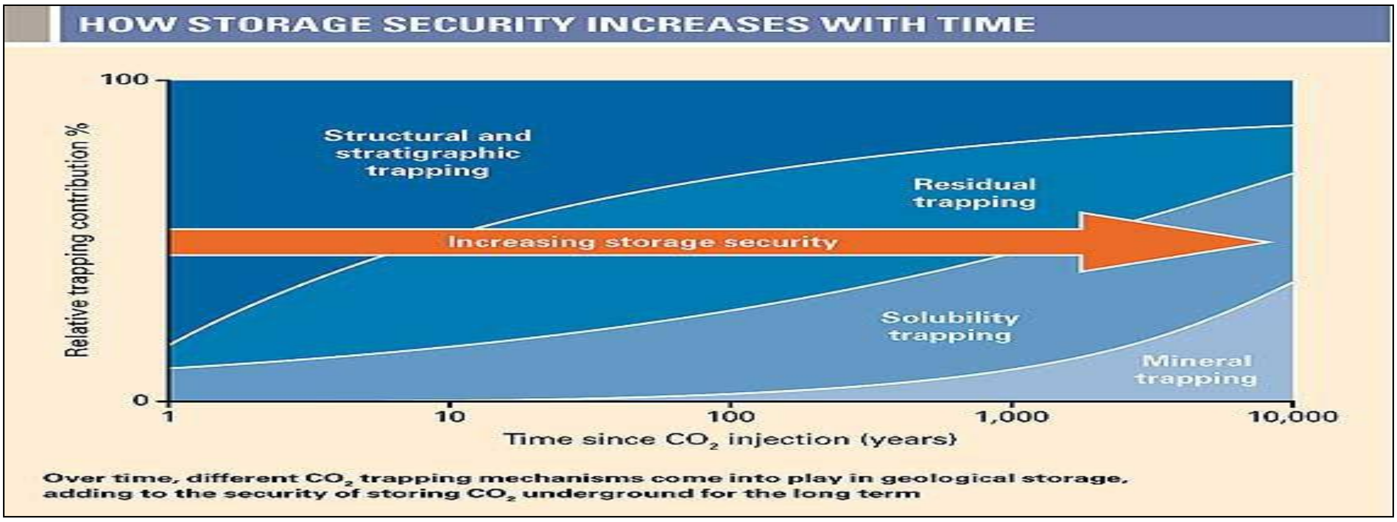

Figure C 1: CO_2 storage security increase with time (IPCC, 2005).

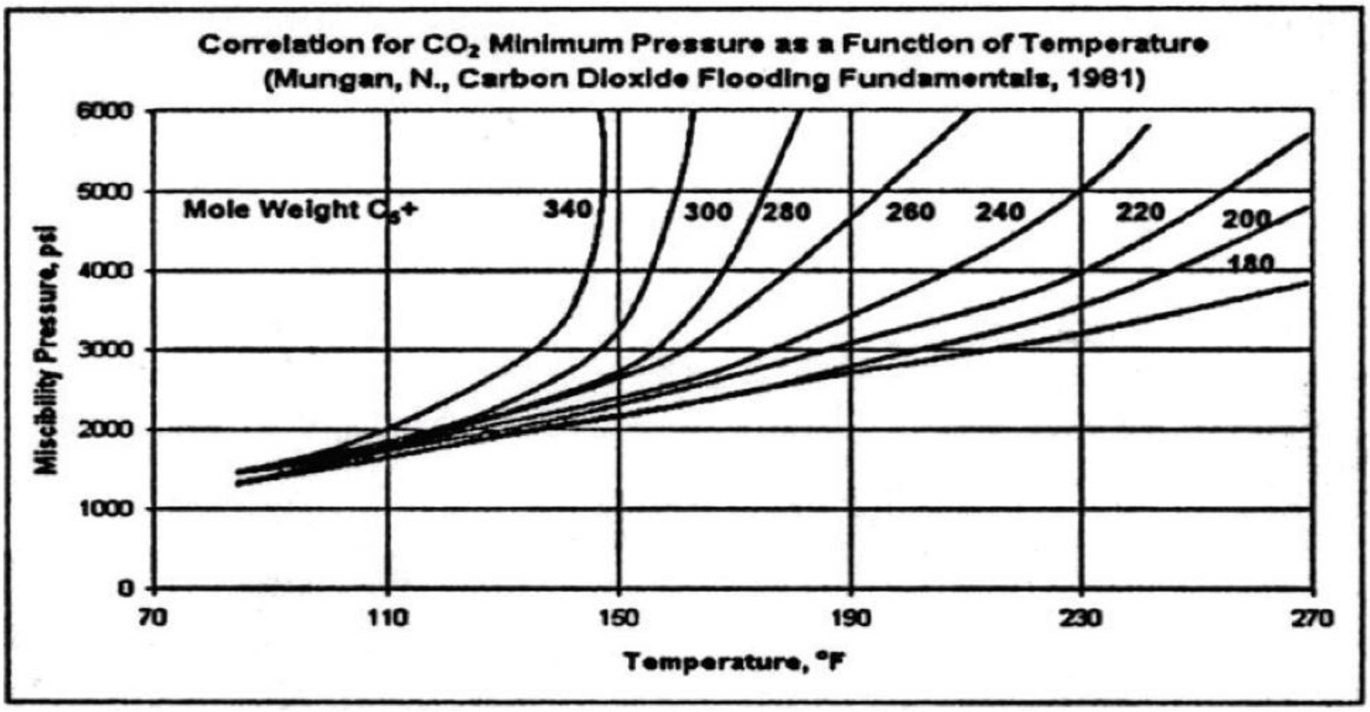

Figure C 2: Correlation for CO_2 minimum pressure as a function of temperature (Mungan, 1981).

APPENDIX D: SIMULATION DATASET

Simulation Run with Eclipse E300 from PETREL RE 2010 Simulation Case for the WAG process . The PVT properties from Eclipse PVTi is found in Appendix E.

The common input files are: AINE_SPE_COMPS_2.DATA, PERMX.GRDECL, PERMY.GRDECL, PERMZ.GRDECL, PORO.GRDECL, PROPS.INC, SUM.INC and finally FLUID_DATA_3.PVO

```
RUNSPEC

TITLE
WAGNEW4

WELLDIMS
  7 34 2 7 /

START
  1 JAN 2011 /

WATER

GAS

OIL

CO2SOL

PETOPTS
INITNNC /

MONITOR

MULTSAVE
  -1 /

MULTOUT

FIELD

DIMENS
  20 18 40 /

COMPS
  11 /

TABDIMS
  1 1 206 5* 1 1* 1* 1* 1 /

EQLDIMS
  1 /

GRID

INCLUDE
```

```
'WAGNEW4_GRID.INC' /

NOECHO

INCLUDE
'WAGNEW4_GRID.GRDECL' /

INCLUDE
'WAGNEW4_PROP_PERMX.GRDECL' /

INCLUDE
'WAGNEW4_PROP_PERMY.GRDECL' /

INCLUDE
'WAGNEW4_PROP_PERMZ.GRDECL' /

INCLUDE
'WAGNEW4_PROP_PORO.GRDECL' /

ECHO

EDIT

PROPS

INCLUDE
'WAGNEW4_PROPS.INC' /

REGIONS

NOECHO

INCLUDE
'WAGNEW4_PROP_EOSNUM.GRDECL' /

INCLUDE
'WAGNEW4_PROP_PVTNUM.GRDECL' /

INCLUDE
'WAGNEW4_PROP_EQLNUM.GRDECL' /

INCLUDE
'WAGNEW4_PROP_ROCKNUM.GRDECL' /

INCLUDE
'WAGNEW4_PROP_SATNUM.GRDECL' /

ECHO

SOLUTION

INCLUDE
'WAGNEW4_SOL.INC' /

SUMMARY

INCLUDE
'WAGNEW4_SUM.INC' /

SCHEDULE
```

```
INCLUDE
'WAGNEW4_SCH.INC' /
```

APPENDIX E: PVT TUNNING AND REGRESSION RESULTS

The PVT results during regression and tunning to be used as a compositional fluid model for the reservoir

```
PVTi
ECHO
-- Units: C
RTEMP
--
-- Constant Reservoir Temperature
--
      68.33
/

EOS
--
-- Equation of State (Reservoir EoS)
--
   PR3
/

NCOMPS
--
-- Number of Components
--
      11
/
PRCORR
--
-- Modified Peng-Robinson EoS
--
CNAMES
--
-- Component Names
--
   'N2'
   'CO2'
   'C1'
   'C2'
   'C3'
   'IC4'
   'NC4'
   'IC5'
   'NC5'
   'C6'
   'C7+'
/
MW
--
-- Molecular Weights (Reservoir EoS)
--
        28.013
         44.01
        16.043
         30.07
        44.097
```

```
      58.124
      58.124
      72.151
      72.151
          84
  262.5460323
/

OMEGAA
--
-- EoS Omega-a Coefficient (Reservoir EoS)
--
  0.457235529
  0.457235529
  0.457235529
  0.457235529
  0.457235529
  0.457235529
  0.457235529
  0.457235529
  0.457235529
  0.457235529
  0.457235529
/

OMEGAB
--
-- EoS Omega-b Coefficient (Reservoir EoS)
--
  0.077796074
  0.077796074
  0.077796074
  0.077796074
  0.077796074
  0.077796074
  0.077796074
  0.077796074
  0.077796074
  0.077796074
  0.077796074
/

-- Units: K
TCRIT
--
-- Critical Temperatures (Reservoir EoS)
--
       126.2
       304.7
       190.6
      305.43
       369.8
       408.1
       425.2
       460.4
       469.6
       507.5
  784.5799132
```

```
/

-- Units: bar
PCRIT
--
-- Critical Pressures (Reservoir EoS)
--
    33.943875
    73.865925
     46.04208
     48.83865
    42.455175
       36.477
   37.9664775
   33.8932125
    33.700695
   30.1036575
  13.58280883
/

-- Units: m3 /kg-mole
VCRIT
--
-- Critical Volumes (Reservoir EoS)
--
         0.09
        0.094
        0.098
        0.148
          0.2
        0.263
        0.255
        0.308
        0.311
        0.351
  1.036113501
/

ZCRIT
--
-- Critical Z-Factors (Reservoir EoS)
--
  0.291151404389918
  0.274077797373227
  0.284729476628582
  0.284634795100356
  0.276164620041118
  0.28273695875079
  0.273855549100576
  0.272710871582637
  0.268438914149838
  0.250417484943592
  0.215741677496464
/

SSHIFT
--
-- EoS Volume Shift (Reservoir EoS)
--
  -0.1313342386
```

```
  -0.04273033674
  -0.1442656189
  -0.103268354
  -0.07750138148
  -0.06198372515
  -0.05422489699
  -0.04177245672
  -0.03027789648
  -0.007288775999
  0.2681964164
/

ACF
--
-- Acentric Factors (Reservoir EoS)
--
       0.04
      0.225
      0.013
     0.0986
     0.1524
     0.1848
      0.201
      0.227
      0.251
      0.299
  0.8525617652
/

BIC
--
-- Binary Interaction Coefficients (Reservoir EoS)
--
 -0.012
   0.1    0.1
   0.1    0.1      0
   0.1    0.1      0      0
   0.1    0.1      0      0      0
   0.1    0.1      0      0      0      0
   0.1    0.1      0      0      0      0      0
   0.1    0.1      0      0      0      0      0      0
   0.1    0.1  0.0279   0.01   0.01      0      0      0      0
   0.1    0.1 0.05198   0.01   0.01      0      0      0      0      0
/

PARACHOR
--
-- Component Parachors
--
         41
         78
         77
        108
      150.3
      181.5
      189.9
        225
      231.5
        271
  674.2804214
```

```
/

-- Units: m3 /kg-mole
VCRITVIS
--
-- Critical Volumes for Viscosity Calc (Reservoir EoS)
--
        0.09
       0.094
       0.098
       0.148
         0.2
       0.263
       0.255
       0.308
       0.311
       0.351
 1.036113501
/

ZCRITVIS
--
-- Critical Z-Factors for Viscosity Calculation (Reservoir EoS)
--
  0.291151404389918
  0.274077797373227
  0.284729476628582
  0.284634795100356
  0.276164620041118
  0.28273695875079
  0.273855549100576
  0.272710871582637
  0.268438914149838
  0.250417484943592
  0.215741677496464
/

LBCCOEF
--
-- Lorentz-Bray-Clark Viscosity Correlation Coefficients
--
   0.1023 0.023364 0.058533 -0.040758 0.0093324

--
-- Overall Composition
--
  0.02667980213
  0.001698713993
  0.1470886469
  0.07054659289
   0.10032405
  0.02558063425
  0.06914765197
  0.02937775965
  0.03847087573
  0.05285998249
   0.43822529  /
```

APPENDIX E: DESCRIPTION OF THE POROSITY AND PERMEABILITY DISTRIBUTION

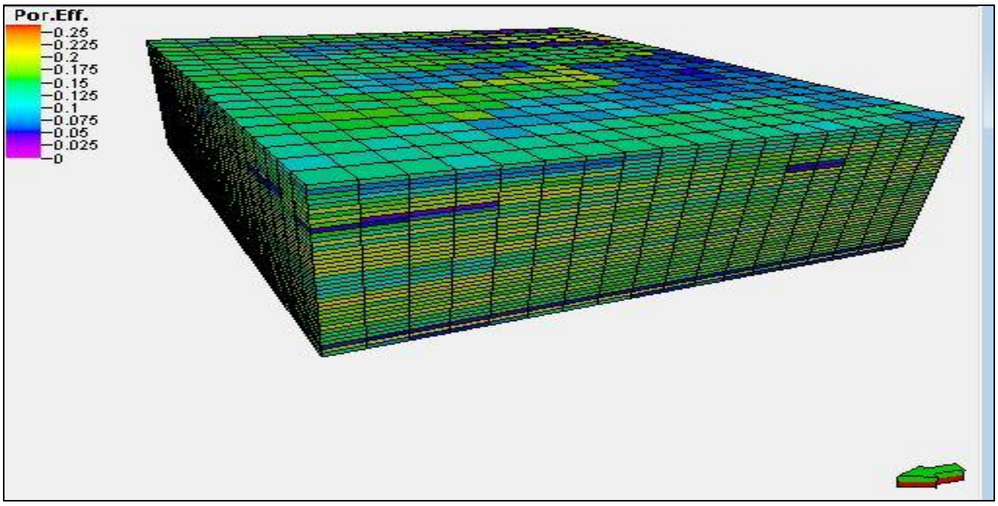

Figure E-1: Porosity distribution of the reservoir model.

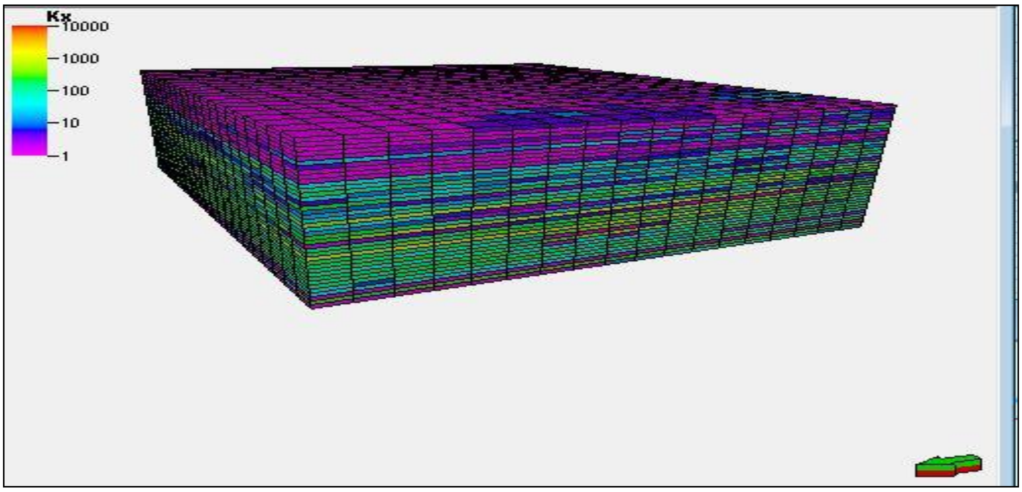

Figure E-2: Permeability distribution of the reservoir model.

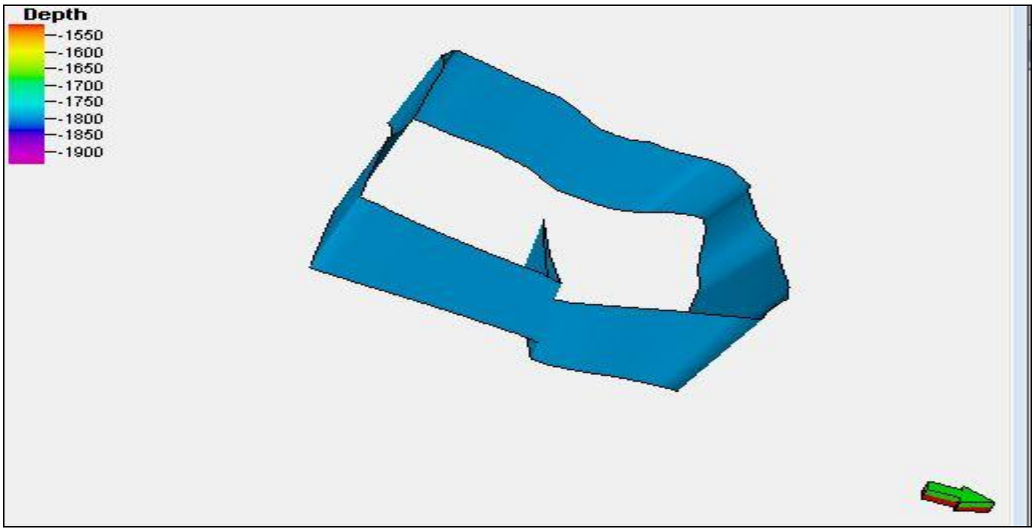

Figure E-3: Description of the edges of the reservoir model.