Feasibility of Sequestration of

CO2 into waterflooded sand-A Simulation Study

By

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Dissertation submitted in partial fulfilment of

the requirements for the

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CERTIFICATION OF APPROVAL

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A project dissertation submitted to
Petroleum Engineering Department
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in partial fulfilment of the requirement for the
BACHELOR OF ENGINEERING (Hons)
(Petroleum)

Approved by,

____

Prof. Dr. Mariyamni Binti Awang

UNIVERSITI TEKNOLOGI PETRONAS
TRONOH, PERAK
JAN, 2015

CERTIFICATION OF ORIGINALITY

This is to certify that I am responsible for the work submitted in this project, that the original work is my own except as specified in the references and acknowledgements, and that the original work contained here have not been undertaken or done by unspecified sources or persons.

Ahmed Abdalmonim Abdalhi Mohamed

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Firstly, I would like to express my greatest gratitude to my supervisor, Prof. Dr. Mariyamni Binti Awang for her ultimate support and advice throughout my final year. Also, I would like to thank CMG support for helping me in my simulation and always replying to my questions and uncertainties.

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Abstract

The increase of Greenhouse gases emission is a growing concern nowadays all over the world. The consequences of the global warming which is caused by the Greenhouse gases emission start to be seen everywhere. Geological sequestration of carbon dioxide is one of the few ways available to reduce the emission of CO_2. Deep saline aquifers considered as the primary option for sequestration of CO_2. However, oil and gas reservoirs offers huge storage capabilities for long term. Even though, CO_2 is currently being used as an enhanced oil recovery operation, injection of CO_2 as a carbon sequestration strategy needs validation. This study focus on storing CO_2 in watered-out reservoirs which are shallower compared to deep saline aquifers, it has relatively similar storage conditions to deep saline aquifers with advantage of the surface facilities and the information available. The watered-out reservoir has been producing for long time until the aquifer has moved up and the water saturation became very high. The injected CO_2 dissolves and diffuses in oil and water, then the dissolved CO_2 reacts with formation minerals and induces precipitation of minerals. The study investigates sequestration of CO_2 by simulation using Computer Modelling Group GEM to simulate the injection and the following processes; which are the structure trapping, the residual gas trapping the solubility trapping and the mineral reaction with the dissolved CO_2 which occurs after hundreds to thousands years. A reservoir model with injectors and producers has been used to evaluate all the stages of trapping and the percentage of CO_2 that will be trapped in each stage. Furthermore, sensitivity analysis was conducted for the permeability, reservoir temperature and water salinity.

Keywords: CO_2 sequestration, watered-out reservoirs, deep saline aquifer, trapping mechanism.

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Chapter 1

Introduction

1.1 Background of Study:

Carbon dioxide is the main greenhouse gas released to the atmosphere throughout human beings activities. CO_2 already exist within the Earth natural carbon cycle. However, the industrial activities, power generation and others are changing the Carbone cycle by adding additional CO_2 to the atmosphere and therefore affecting the ability of natural absorption of CO_2. Fossil fuels such as oil and natural gas are used for generating electricity, industry and transportation considered as the main activities that emit carbon dioxide to the atmosphere.

According to the (EIA, IPCC, 2010) the world annual emission of CO_2 about 30 billion tons and expected to reach 40 billion tons in 2030. Even though half of this huge amount of carbon dioxide, will be absorbed through natural sink, the remaining part of CO_2 may stay in Earth's atmosphere for centuries. In order to reach equilibrium thousands of carbon storage projects has to be initiated.

Carbon capture and sequestration (CSS) phenomena comes after the rising of the global warming issue and increase of the earth temperature. The earth consist of layers that are very different from each other, it has been deposited in different geological times. Thus, it has different properties, oil and gas reservoirs is within those layers. The idea of CSS is mainly about capturing the emitted CO_2 from its sources such as industrial activities, power plants and gas reservoirs. Then CO_2 is transported and stored underground in many media such as:

1.1.1 Deep Saline aquifers

Deep saline aquifers are underground layers, widely distributed filled with saline water, that cannot be used for human consumption (Long, Vijay, David, Bruce, Mohamed, & Chadon, 2009). Those aquifers can accommodate huge amount of CO_2 which can be injected into aquifers in its super critical state (31.1° and 7.4 MPa) by applying techniques similar to the enhanced oil recovery (CO_2 injection). The sequestration is achieved by trapping CO2 in the pore spaces either by capillary forces, dissolution in the saline water and reaction with the minerals of the rock.

1.1.2 Coal seams

It produces methane naturally, the production can be enhanced by injection CO_2 in the seam. Therefore it has a good potential to store CO_2 for long term.

1.1.3 Oil and Gas Reservoir (EOR)

CO_2 has been used for EOR for more than 30 years, it accounts for 6% of USA oil production. CO_2 reduce the oil viscosity by oil swelling and therefore increase the capillary number. While injecting CO_2 in the reservoir much of the injected CO_2 trapped in the pore spaces and the reset produced along with the oil. It has been suggested that 130 billion ton of CO_2 can be stored throughout using CO_2 in EOR (Pawar, Warpinski, Benson, Grigg, Krumhansl, & Stubbs, 2004).

The main concern with CO_2 is the long term storage, does CO_2 remain underground for hundreds years, thousands years? Since the oil and gas have being trapped there for geological times.

The previous media mentioned are the conventional media for storing CO_2. However, this research covers CO_2 injection in oil and gas reservoirs not as an EOR method, but intentionally injected for carbon sequestration, when the reservoir is watered-out and no longer economical and useful for oil and gas production.

The water can flow to the wellbore and cause the reservoir to be watered-out (water flooded) through two mechanisms. Either it flows from the water aquifers or it has been injected through water flooding to support the aquifer and sweep the oil. The formation water can come from the water saturated zone within the reservoir or any zone below or above the oil zone. Many reservoirs are attached to an active water aquifer either it is from the edge or the bottom. Some other reservoirs are their pressure drops with oil production that might be due to weak aquifer support. Therefore, water is injected for pressure maintenance.

Water drive reservoirs are defined as the reservoirs that is in communication and bounded by water aquifer. During the oil production the water aquifer expand and replace the produced oil. Therefore, maintain a very small pressure drop across the reservoir. Water drive reservoirs are classified according to the position of the aquifer into three types:

- Peripheral water drive; the water aquifer is surrounding the reservoir in a circular form. Either the whole reservoir or partially.
- Edgewater drive; the water aquifer is attached to the sides of the reservoir
- Bottomwater drive; the water aquifer is attached to the bottom of the reservoir.

1.1.4 Watered-out reservoirs

Watered-out reservoirs are reservoirs that have one of the above water drive system. However, it has a very high water saturation, because the field has been on production for a long time until the water aquifer reaches the perforations and therefore resulted in a very high water cut, basically reservoirs that depleted because of high amount of water produced. Those reservoirs has been depleted due to the excessive water production from the aquifer. However, the reservoir will not be suspended, it is going to be used for storing CO_2 and trap it for long term. The reservoir assumed to have strong to moderate active water aquifer.

Sequestration of CO_2 in watered-out reservoirs is a promising solution to the sustainable development issue, by storing CO_2 underground the natural presence of CO_2 in the atmosphere will be maintained at acceptable level. Millions of tons of CO_2 can be stored in the depleted oil reservoirs and it has no effect on the agriculture, forestry, fishing, other industries and land use. It also doesn't depend on the climate conditions. Therefore, it is considered as the most significant sink option available for dispose CO_2.

The storage process of CO_2 in the watered-out reservoirs is not an easy and simple process, it does face many challenges when applying it. The ability of efficiently monitor and model the injected gas, as well as gas handling. CO_2 is stored underground to save the environment. Therefore environmental consideration are very critical when it comes to CO_2. The movement of the injected gas overtime must be monitored, ensure there is no any side environmental damages.

1.1.5 Why watered-out reservoirs?

Watered-out reservoirs have a good potential for carbon sequestration with the advantages of having a shallow depth compared to the deep saline aquifers and therefore low cost for project initiation and low operation cost. Moreover, the availability of the facilities and other infrastructure. Oil and gas fields has a huge underground information available, Seismic, well logging and reservoir and properties. Thus, the probability of the success of the injection operation is relatively high, where the facility and the desire subsurface data is available.

1.2 Problem statement:

CO_2 has been successfully stored in deep saline aquifers which are deep, big and have high reservoir pressure. Water flooded reservoirs has a high water saturation and relatively shallow depth compared to deep saline aquifers. We do not know that the presence of high water saturation in shallow depth can trap CO_2 in watered-out reservoirs for long term. Moreover, the amount of CO_2 that can be trapped in each stage will be estimated.

By succeeding in applying this new approach huge amounts of CO_2 can be stored underground safely for long term.

1.3 Scope of Study:

The study undertaking storing CO_2 into water flooded reservoirs only. The reservoirs that is supported by active, strong water aquifer, has high water saturation due to the upward migration of water aquifer to simulate the process. Field simulation model will be created with CMG software and reservoir properties will be determined by history matching for different scenarios which will be developed in order to find the best sequestration scheme. The injected carbon dioxide will be in its super critical state.

The study will focus on the trapping mechanisms of CO_2 and monitoring the reservoir pressure after injecting certain amount of CO_2.

1.4 Objectives of study:

- To estimate how much of the injected CO_2 will be trapped as residual gas
- To estimate the amount of CO_2 that will dissolve in the brine water.
- To estimate when and how much of the injected CO_2 will mineralize.
- To conduct sensitivity analysis in order to come out optimum conditions for CO_2 storage.

1.5 Relevancy feasibility of the study:

The Geological sequestration of CO_2 is a process of storing CO_2 in underground reservoirs. In our case in this project is the watered-out reservoirs. CO_2 injection has been used as an EOR mechanism from more than 4 decades. In some cases CO_2 sequestration is combined with hydrocarbon recovery. The differences between EOR and sequestration is that CO_2 will ultimately left in the place when hydrocarbon recovery process has ended. Furthermore, the motivation is environmental besides pressure maintenance, reduction of viscosity or sweeping the hydrocarbons.

Chapter 2

Literature review

Carbon capture and storage (CCS) covers gathering the carbon dioxide from the industrial sources and the power generation stations and injecting it underground. This could contribute significantly in the reduction of emitted CO_2 to the atmosphere (IPCC, 2005). In this chapter the projects undertaken storing CO_2 in high water saturation reservoirs will be reviewed. In carbon sequestration and storage there are four main trapping mechanisms which will be discussed below.

2.1 Trapping Mechanisms

According to Long, Vijay, David, Bruce, Mohamed, & Chadon carbon dioxide can be trapped in the reservoir through four main trapping mechanisms, which are; structural trapping residual trapping, solubility trapping, and mineral trapping

2.1.1 Structural trapping

Similar to the oil and gas, for CO_2 to remain trapped under ground some reasons have to be established and one of those reasons is the structural geological seal that can prevent CO_2 from migrating upward or escaping anywhere. Structural trapping established as soon as the CO_2 injected and is responsible for trapping most of the injected CO_2 in the early times, when CO_2 is very mobile. Nevertheless, it is considered the least secure mean of trapping since the possibility of leakage is very high.

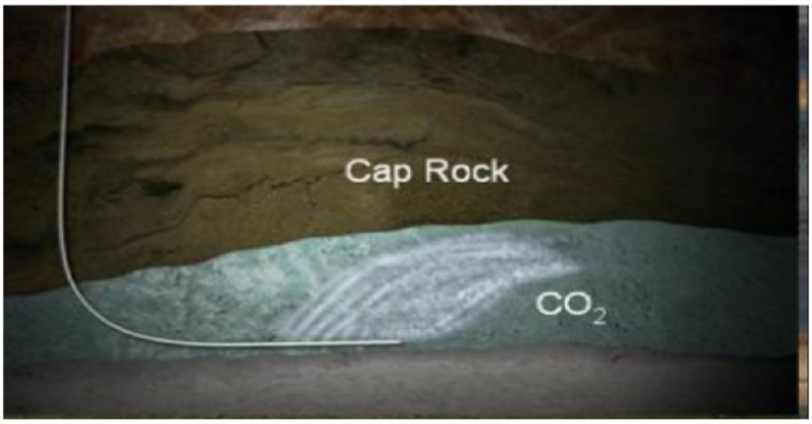

Fig (2.1): structural trapping

2.1.2Residual gas trapping

The residual gas tapping is taking advantage of the wettability and the surface tension between the gas and the rock particles. As the CO_2 is injected into the reservoir it flows through the pore spaces and as it continues to move, will displace fluids and fluids again replace it, but some of CO_2 remain in the pores and become immobile. This is similar to the residual oil saturation to which EOR is directed. Therefore, residual trapping immobilize relatively small amount of the injected CO_2 in pore spaces. However, the development of future cracks or faults might lead some of the immobilized gas to be released. The figure below is an illustration of the trapping mechanism (Tran, Shrivastava, & kohse, 2009).

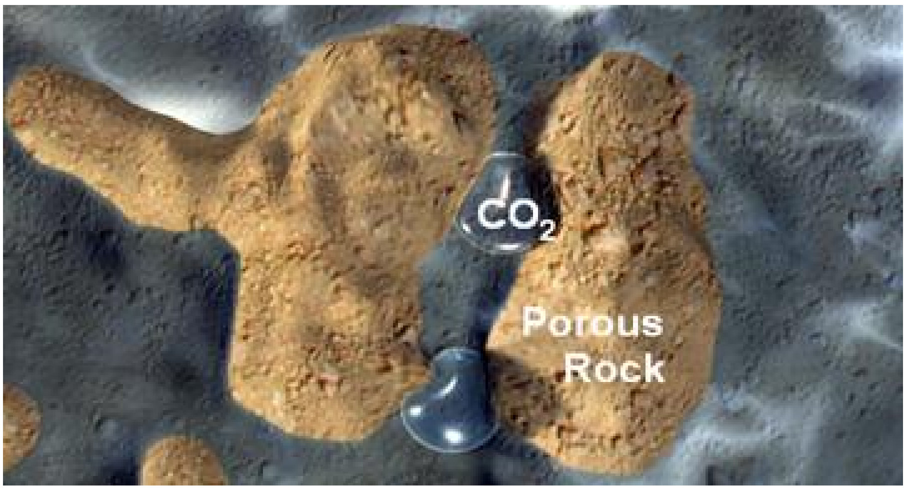

Fig (2.2): Residual trapping

2.1.3 Solubility trapping

The mechanism is taking advantage of ability of carbon dioxide to dissolve in other fluids in its supercritical state as well as gaseous state. CO_2 will be trapped when it dissolves in the saline water. Therefore, the water with dissolved CO_2 is slightly heavier than the normal water and then it will sink away to the bottom of the reservoir over time, making trapping carbon dioxide is even more safely. This process is called the convective dissolution. The dissolution of carbon dioxide into saline water tends to be a process happens very slowly. However, it provides a very secure storage. Below is an illustration of the solubility trapping (Leonenk & Keith, 2008).

Fig (2.3): Solubility tapping

2.1.4 Mineral trapping

After a considerably long time, form hundreds to thousands years a carbonate acid may react with the minerals in the formation resulting in precipitation of carbonate minerals. This mechanism provides ultimate security for the injected CO_2 (Thuibeau, Nghiem & Ohkuma, 2007).

Below is an illustration of the trapping mechanism.

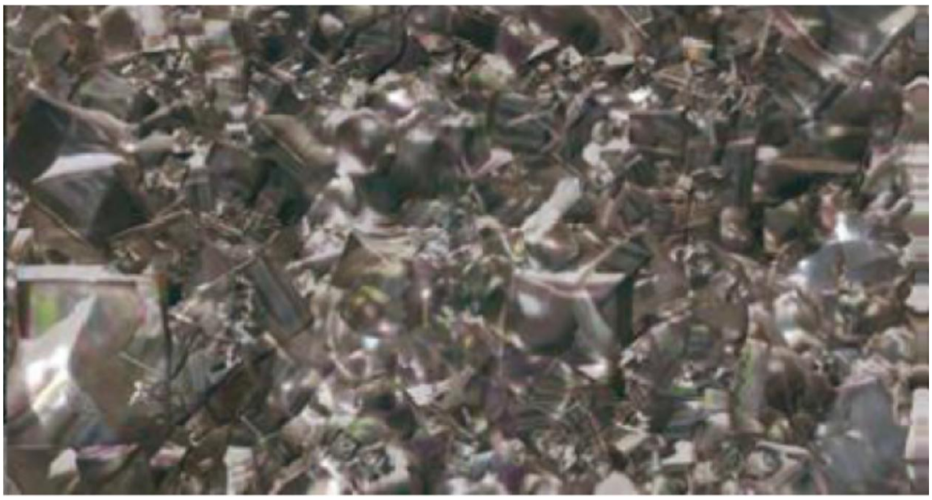

Fig (2.4): mineral trapping

The final CO_2 sequestration is expected to complete after a very long time. Each of the above mentioned trapping mechanisms occurs in different time and each one of them has a certain level of security. Zhang (2003) in his PHD study on carbon sequestration in deep saline aquifer has illustrated, the time frame, the security of the storage and governing principles for each of the above trapping mechanisms.

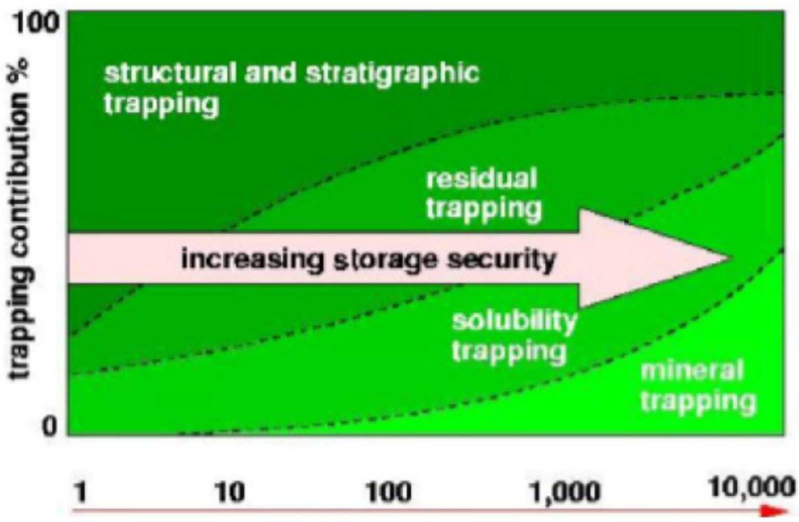

Fig (2.5): The time frame for the drive mechanisms, security and contribution

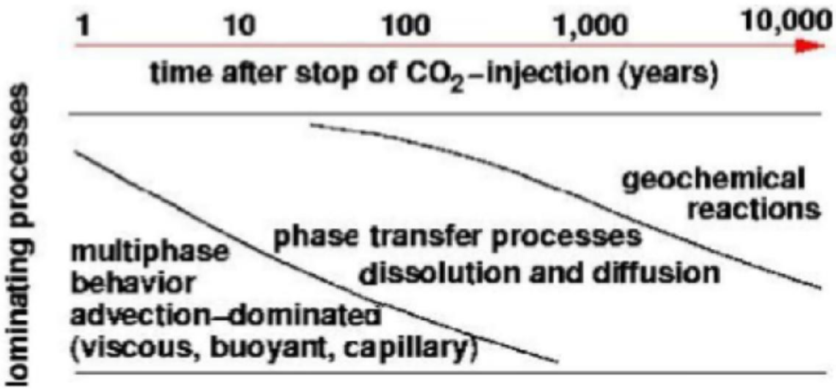

Fig (2.6): The governing principles

By utilizing all of the above mentioned trapping mechanisms we ensure that the injected CO_2 is isolated from drinking water sources and prevented from escaping to the atmosphere.

In the background some of the CO_2 storage media was mentioned. However, in this chapter only two of them will be covered, sequestration in deep saline aquifers and hydrocarbon reservoirs.

2.2 Storage in deep saline aquifer

It has a very high water saturation which is in a way similar to watered-out reservoirs. Kumar, Noh, Pope, Sepehrnoori, Bryant &Lake (2005), in their research they have pointed out the parameters that they looked at while simulating CO_2 sequestration in saline aquifers which has high water saturation and relatively low pressure. These parameters are the absolute and relative permeability, the ratio between vertical and horizontal permeability, the residual gas saturation, the temperature and the dipping angle of the aquifer. The aquifer has a length of 53000 ft, and width of 53000 ft and thickness of 1000 ft. The pressure is constant throughout the aquifer and the position of the injector is in the center of the aquifer. The injection of supercritical CO_2 continued for 10 years and the simulation continues up to 1000 years and in some cases 100,000 years. The computer modeling group (CMG) GEM simulator has been used for the conducting the simulation.

2.2.1 Effect of aquifer parameters

The aquifer properties has a great impact on the sequestration process, in the previous model t has been found that when there is a smaller formation permeability, will result in less CO_2 will be sequestrated. This might be due to small injection pressure because the maximum bottom hole pressure for injection well is limiting the injection rate (the maximum BHP must be set in the simulator). Furthermore, when the temperature is high a great percentage of CO_2 goes to the aqueous phase. Likewise, small water salinity result in more CO_2 dissolution because the solubility has increased. Moreover, bigger value of aquifer dipping result in more lateral movement of CO_2 which is eventually result in more dissolution of CO2. Even though the vertical and horizontal permeability ratio does not affect the distribution of CO2, small values of Kv/ Kh ratio leads to greater horizontal movement of the CO2 in the layers into which the CO2 injected.

According to Tran, Shrivastava and kohse the residual gas saturation has a great impact on the storage, when there is small values of residual gas saturation, logically means a great amount of CO2 will be mobile even after 1000 years, since not much of CO2 is immobilized by pore spaces. Conversely, when we have high value of residual gas saturation, a considerable amount of CO2 is trapped as a residual gas and therefore less mobile CO2.

2.2.2 Influence of mineralization:

Referring to Xu, Apps and Pruess (2001) study, another set of simulation is performed to know the impact of the mineralization on the storage. It has been pointed out that there are five mineral reactions were used in their simulation with the following equations

Calcite + $H^+ = Ca^{2+} + HCO^-_3$

Anorthite + $8H^+ = 4H_2O + Ca^{2+} + 2AL^{+3} + 2SiO$

Kaolinite + $6H^+ = 5H_2O + SiO_2 + 2AL^{+3}$

Siderite = $Fe^{2+} + CO^{-2}_3$

Glauconite + $14H = 1.5K^+ + Fe^{3+} + 0.5Fe^{2+} + Mg^{2+} + AL^{3+} + 7.5SiO_2 + 9H_2O$

With certain concentration some calcite has precipitated after 10000 years. According to the study 2.7% of the injected CO_2 in mineralized, 6.4% dissolved into water and 90% remains in its gaseous phase.

The study suggested that in order to increase the solubility and mineral trapping, water should be injected after the injection of CO_2. However, this might have a significant impact of the residual gas, which will be replaced by water. The impact might be reduced by injection water saturated with CO_2.

2.3 Storage in oil fields

Oil reservoirs after primary depletion or in combination with secondary and tertiary recovery offer good storage capabilities for CO_2. Considering the leak tightness and the knowledge on reservoir rock itself after years of oil production, it also applied for gas reservoirs. In the process of injecting CO_2, the residual oil will be displaced. The fluid flow behavior through the porous media will be more complex compared to gas reservoirs.

CO_2 injection projects up to date, have focused on reservoirs with API gravity between 29° to 48° and depth between 760m to 3700m. More than 80% of the reservoirs worldwide are suitable for CO_2 sequestration (Le Gallo, Couillens & Manai, 2002).

The streamline-based simulator has been used by Ran, Tara & Martin (2008) to design storage for CO_2 in aquifer attached to an oil field on production. When injecting CO_2 into the aquifers there are three phases present; hydrocarbon phase, aqueous and solid phase.

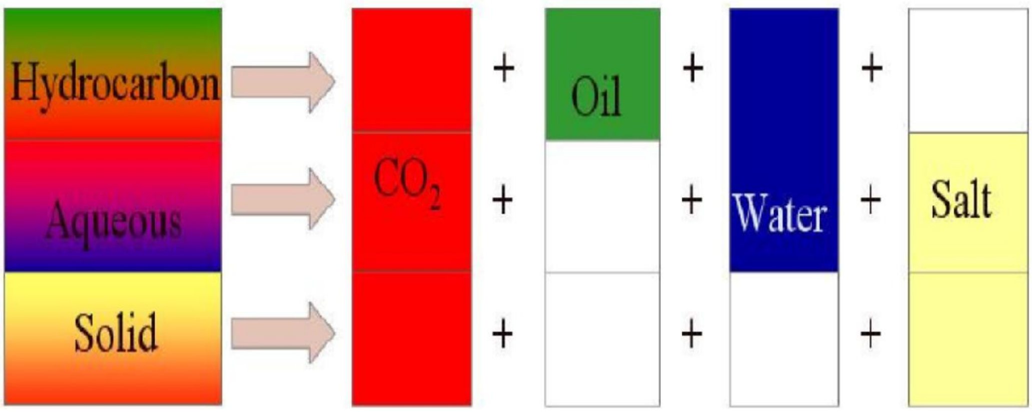

Fig (2.7): phases in the reservoir

They capillary pressure is ignored and assumed incompressible flow. A sector cropped form the SPE North Sea sandstone model with porosity of 0.2 and initial oil saturation of 0.79 has been used for simulation. The CO_2 used for in field has viscosity which 50 times less than the oil viscosity and 10 times less than water viscosity.

Firstly, water injection has been carried out in order to reach the residual oil saturation of 0.471 and then CO_2 and brine injected together followed by brine injection only. The optimum WAG ratio defined as the ratio at which the water and CO_2 phases move at the same speed. The injection of water and CO_2 together is an effective mechanism to recover oil. In some cases the water is injected more than the optimum water ration so that the water can move ahead of CO_2 and therefore some of the injected CO_2 can be trapped as residual gas saturation. However, this is lead to an early breakthrough of water. They concluded that 90% of the injected CO_2 can be trapped underground or dissolve if CO2 is injected at the optimum WAG ratio.

Chapter 3

Methodology

In this chapter the approach used to achieve the objectives of the study will be explained. A sector of one of reservoir will be use to conduct the simulation using computer modeling group GEM.

The model used for the study has 10,000 grid cells and 1850 psi initial reservoir pressure. The basic idea is to start production until the reservoir become watered-out. Then CO_2 will be injected for 1 year. The well will be shut in, the movement of CO_2 will be monitored for 200 years.

The simulation inputs for the Base case is as follow

Parameter	Value
Reservoir Top, m	1200
Length, m	1000
Width, m	250
Thickness, m	50
Grid	100*5*20
Temperature, °F	150
Initial Pressure, Psi	1850
Salinity, ppm	10,000
Kv/Kh	0.1
Horizontal permeability, mD	400
Residual oil saturation	.25
Residual water saturation	0.28
Residual gas saturation	0.18
Maximum Injection pressure, Psi	4200
Maximum Injection rate, $MMft^3$	1
Formation fracture pressure, Psi	4500

CO_2 Properties	
Critical pressure, Psi	1070
Critical temperature, °F	87.77
Critical volume, cu ft/Ib-mole	1.5076
Molecular weight, Ib/Ib-mole	44.01
Viscosity, cp	0.0115279

Table (3.1): Simulation inputs

Below are the relative permeability curves

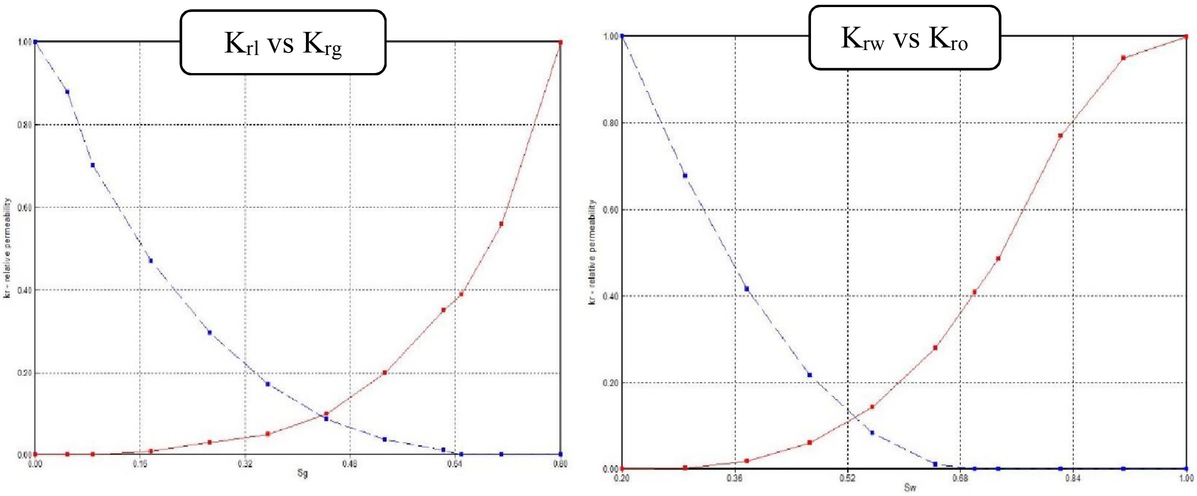

Fig (3.1): Relative permeability curves

The simulation started with water injection in the reservoir in order to produce the oil and increase the water saturation. Then I have started to inject 1 MMCF/day of CO2 for one year, while the injection I was monitoring the reservoir pressure and making sure it does not come close to the formation fracture pressure. In this stage I focused on the residual gas trapping and solubility trapping. Then some chemical reactions between the reservoir rock and CO_2, which will result in precipitation of minerals and therefore leads to what we call mineral trapping. Furthermore, I have conducted some sensitivity analysis for 3 parameters. The first parameter changed was the permeability with (400mD, 300mD, 200mD and 100mD) while monitoring the effect of different permeability values on the amount of CO_2 trapped in each stage. Besides the permeability, the temperature (100°F, 150°F, 200°F & 250°F) and the salinity with (10,000 ppm, 50,000 ppm and 20,000 ppm).

Finally, the results will be collected and analysied and the reseach will be concluded.

3.1 Project activities:

The chart below summarize the project flow for FYP1 & FYP2.

Collect the necessary reservoir data for simulation

Produce the reservoir until the water cut reaches 100%

Injection of CO_2 for 1 year

Monitor the movement of CO_2 for 200 years

Defining solubility parameters in order so simulate the solubility trapping

Define the chemical reactions with the reservoir rock

Run the simulation for the base case

Identify three sensitive parameters; permeability, temperature & salinity

Run sensitivity analysis

Analysis and discussion of the results

3.2 Gannt chart

Millstone	Tasks	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28
Extended Proposal	Topics selection	■	■																										
	Research and study			■	■	■																							
	Submission of extended proposal						■																						
Proposal defense	Research continues						■	■	■	■																			
	Proposal defense presentation									■																			
Interim Report	Select field for simulation										■	■																	
	Collect reservoir and fluid properties data											■	■																
	Start simulation of CO_2 injection												■	■															
	Submission of interim report														■														
Progress Report	Simulation of residual gas, solubility& mineral trapping															■	■	■	■	■	■								
	Submission of progress report																					■							
Pre-Sedex	Finalizing the simulation																					■	■						
	Pre-sedex presentation																							■					
Final report& Viva	Submission of final report draft																								■				
	Submission of dissertation (soft copy)																									■			
	Submission of Technical paper																										■		
	Viva																											■	■
	Submission of dissertation (Hard bound)																												■

3.3 key millstones

The project key millstones are as follow:

1. Find a reservoir model in which CO_2 sequestration can be performed
2. Simulation of the structural and residual trapping
3. Simulation of the solubility of CO_2 into water
4. Simulation of the mineral trapping.
5. Running of Sensitivity analysis.
6. Analysis and discussion of the results
7. Prepare technical paper

Chapter 4

Results and discussion

The first stage in this study is to produce the oil until the water cut increase to certain 100 % percent. The CO_2 injected for one year at rate of 35000 SCF/day, then the CO_2 injector was shut down and the movement of CO_2 has been monitored for 200 years.

4.1 Structure and residual trapping

The first case of simulation was built to include the structural trapping of CO_2 besides the residual trapping.

Below are the results of the first run.

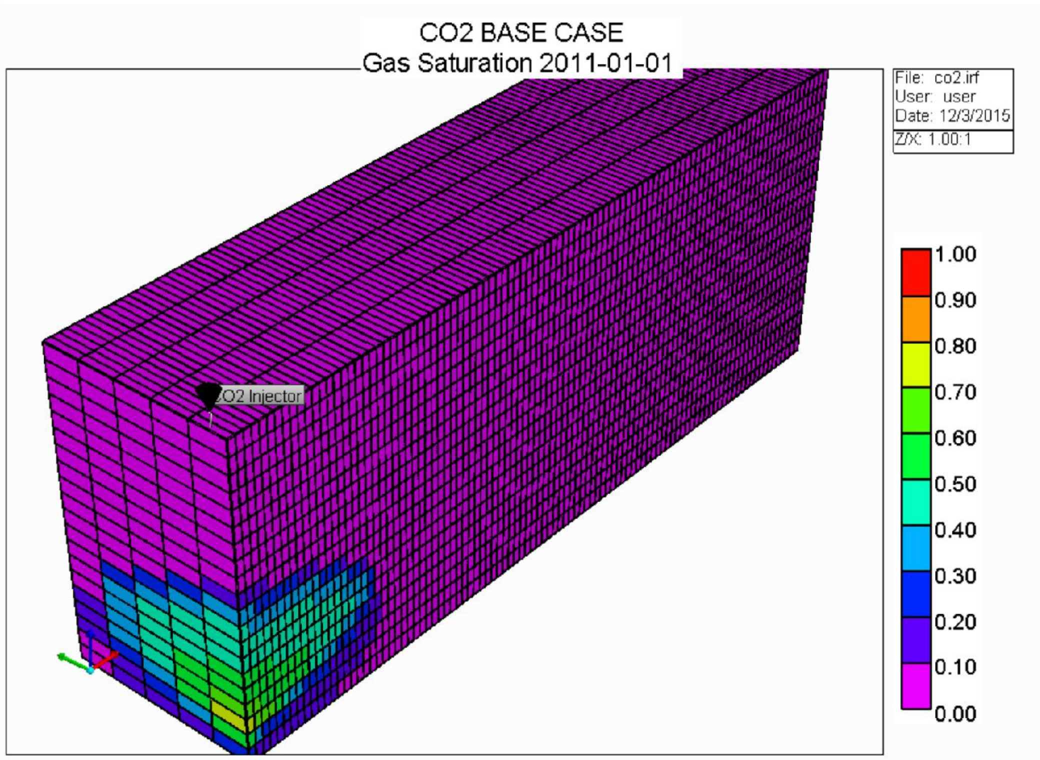

Fig (4.1): CO2 at the end of injection period

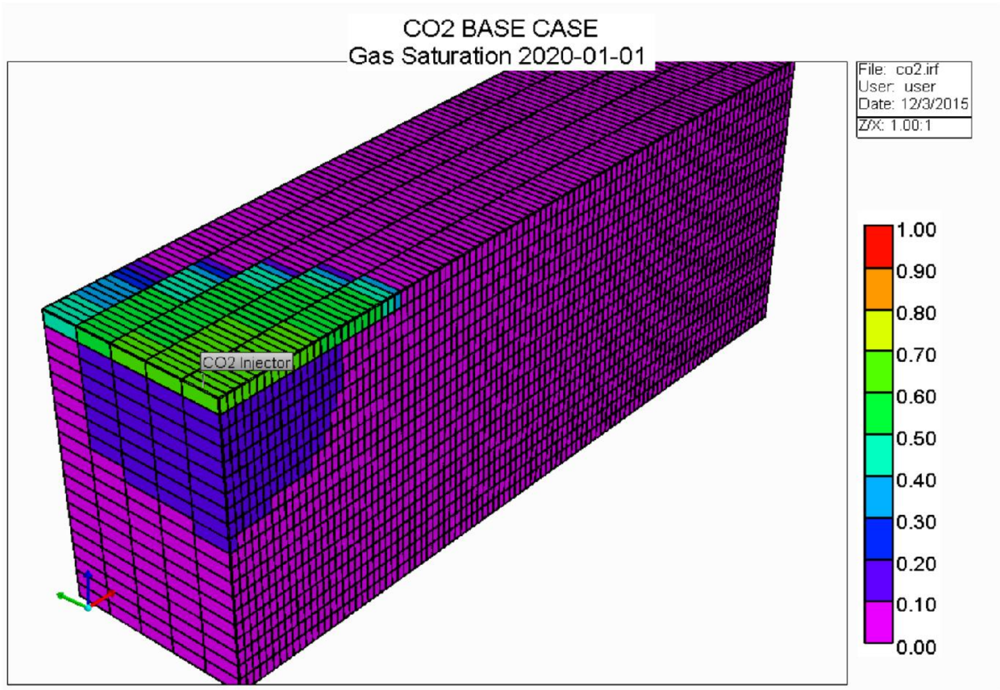

Fig (4.2): CO2 after 20 years

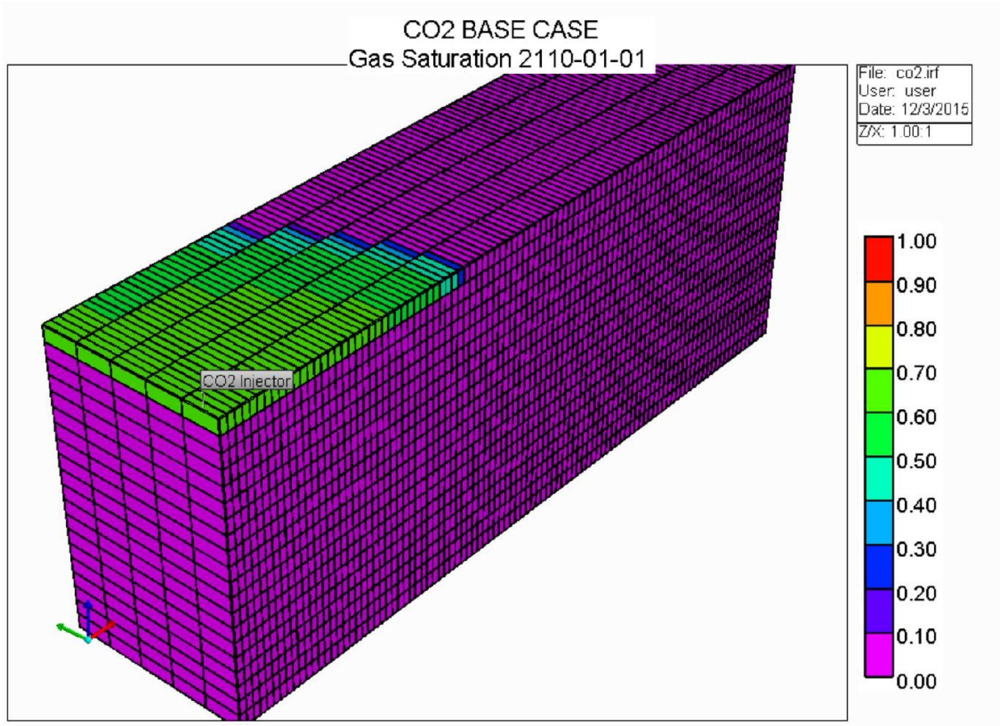

Fig (4.3): CO2 after 100 years

Discussion

Fig (4.1) showing CO_2 at the end of the injection period, CO2 tends to override the water, the average saturation of CO_2 around the well bore is 0 .6. In fig (4.2) CO_2 continues to override, the saturation increasing gradually in the upper part in average of 0.8 at the same time the saturation is decreasing in the lower part of the reservoir. Fig 10 shows the CO_2 after 100 years, there is no much change except CO_2 keeps migrating to the upper part. This indicates that greater amount of the injected CO_2 is trapped by the cap rock, and some of it trapped as residual gas. Having huge amount of the injected gas trapped by the cap rock which considered as the least security storage is relatively dangerous, because it might crack and there is a possibility of leakage. To avoid that, the amount of gas trapped as residual gas need to be increased because it is more secured that the cap rock.

In order to increase the amount of CO_2 trapped as a residual gas, another case with water injection will be run. Injecting water over CO_2 will increase the amount of gas left behind. Two different cases of water injection has been run, injection of 150 bbl/day and 300 bbl/day. The results are shown below

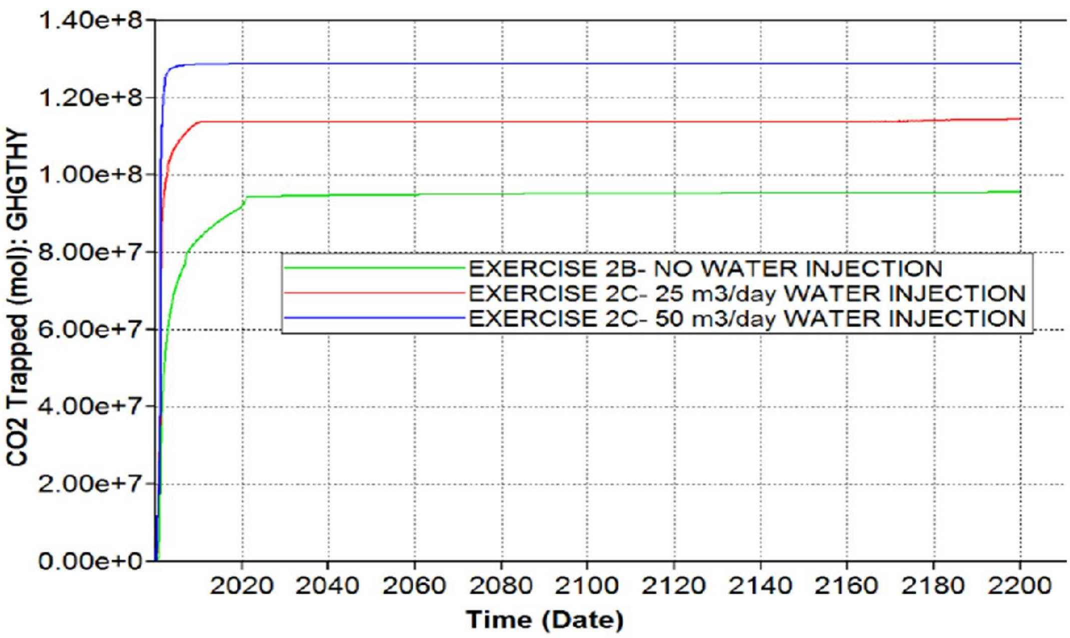

Fig (4.4): water injection cases

The above figure shows a comparison between 3 cases; no water injection, 150 bbl/day water injection and 300 bbl/day injection. Clearly the 300 bbl/day is the best case. This indicates that injection water over CO_2 will significantly increase the amount of gas trapped as residual gas. Taking into consideration the formation fracture pressure, because injecting huge amount of water may result in cracking the reservoir rock.

4.2 Solubility trapping

Additional cases has been run in order to investigate the solubility trapping and how much of the injected CO_2 will dissolve in the water. The results are shown below

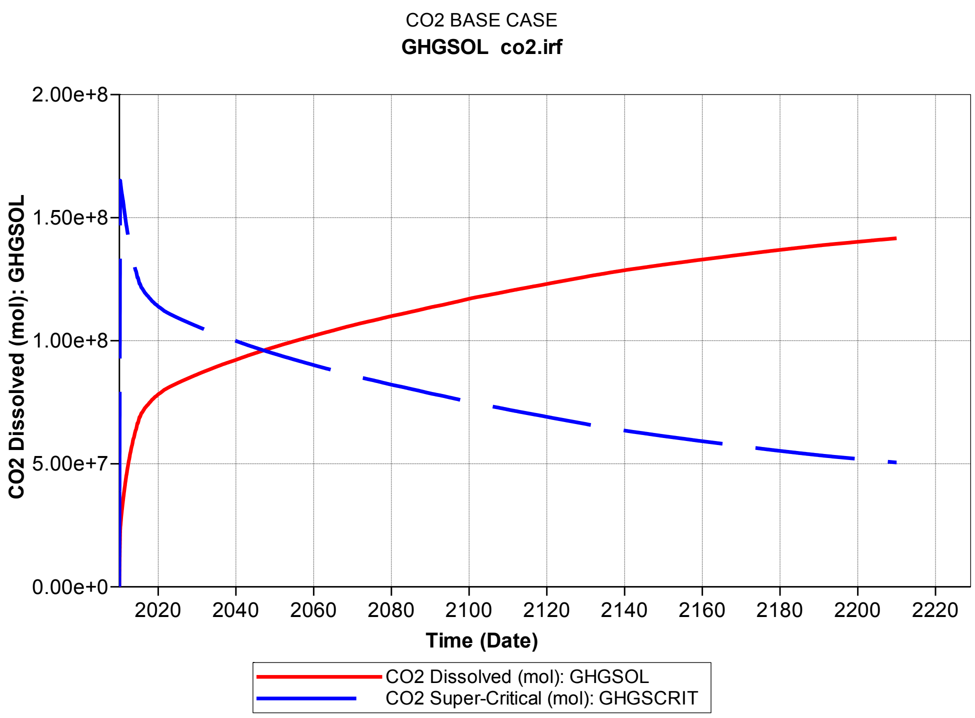

Fig (4.5): CO2 dissolve in the water

As the figure showing the amount of CO_2 dissolved in the water is increasing with time unlike the CO_2 in Super critical state. The solubility of CO_2 in the water largely relies on the formation permeability, reservoir temperature and water salinity which will be illustrated further in the sensitivity analysis.

By displaying the water mole fraction (CO_2), which means the water mole fractions with dissolved CO_2, it has been found that the water with dissolved CO_2 sink to the bottom of the reservoir since it has a higher density, offering a very secure storage for the dissolved CO_2.

The figures below illustrate the water mole fraction CO_2.

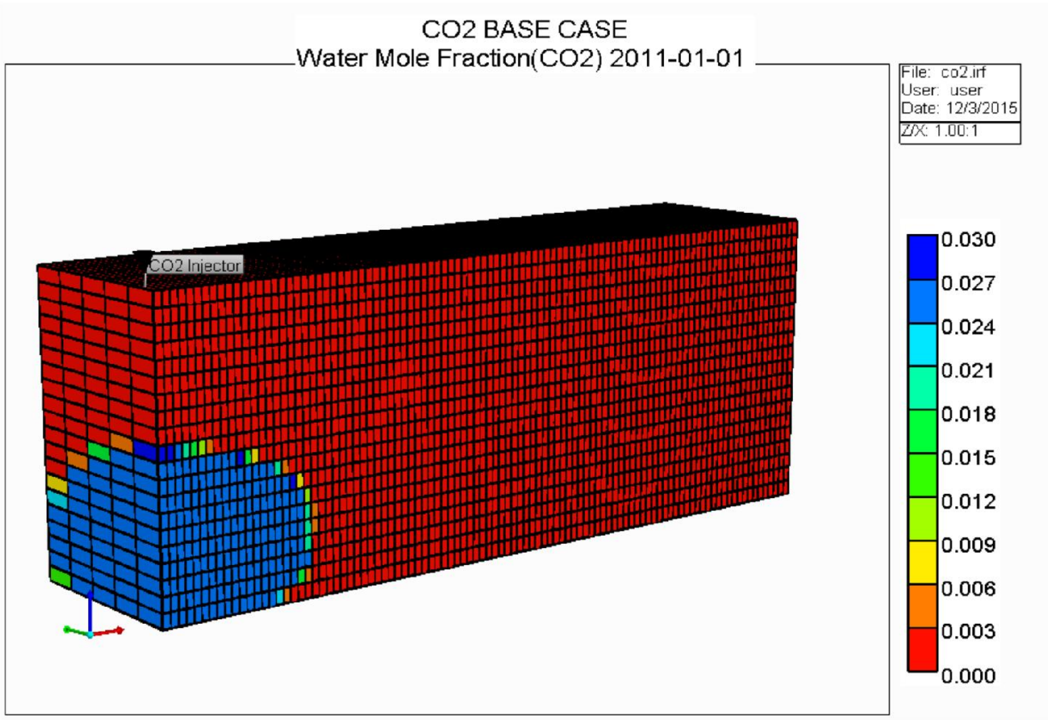

Fig (4.6): Water mole fraction (CO_2) after the injection

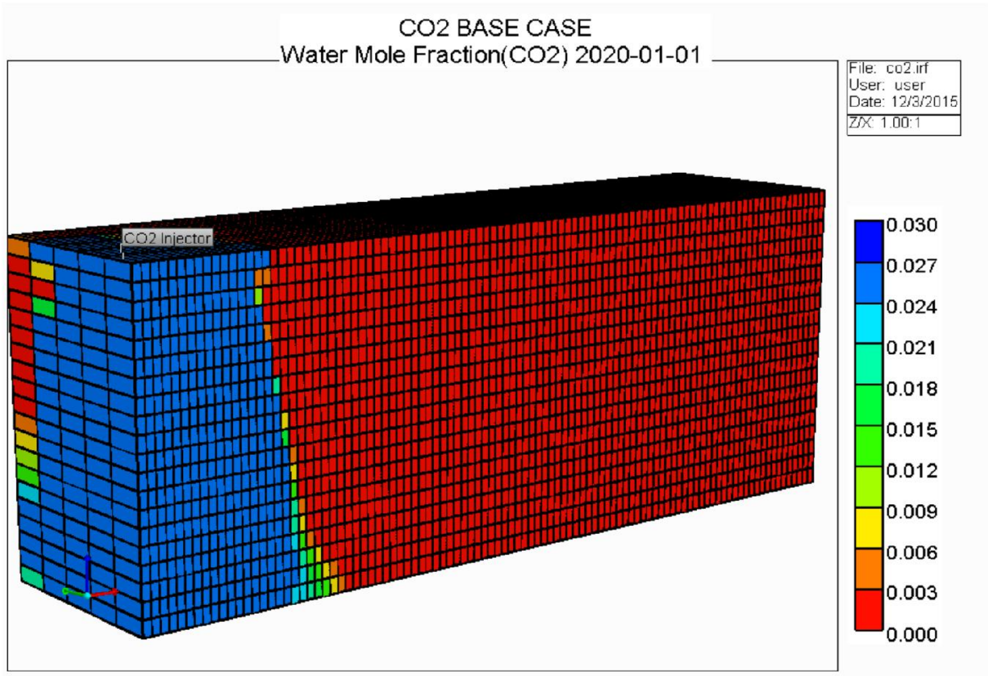

Fig (4.7): Water mole fraction (CO_2) after 20 years

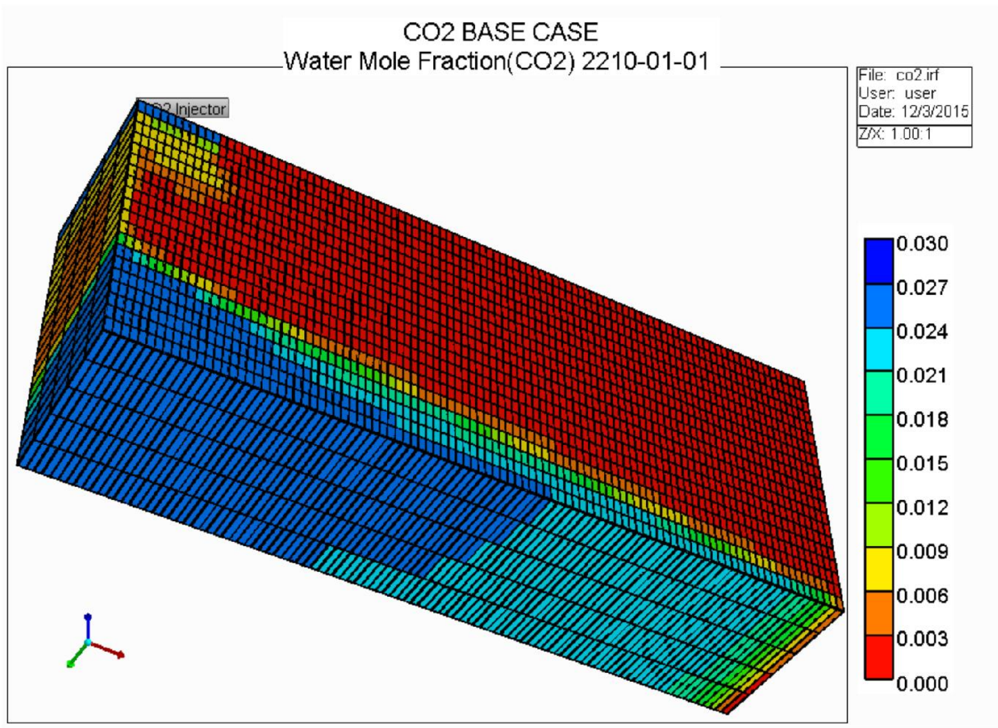

Fig (4.8): Water mole fraction (CO_2) after 200 years

To confirm the previous theory of the water with dissolve CO_2 is heavier and will sink to the bottom of the reservoir. As shown in the figure below. The water density has been displayed And the changes has been observed over the 200 years. As we can see in the lower part of the reservoir where CO_2 is dissolve, the water has slightly high density compared to the other parts. CO_2 start to dissolve in water many years after the injection and the density of the water keeps changing even after 200 years after the injection has stooped, my guess it will not stop until all of the water is saturated.

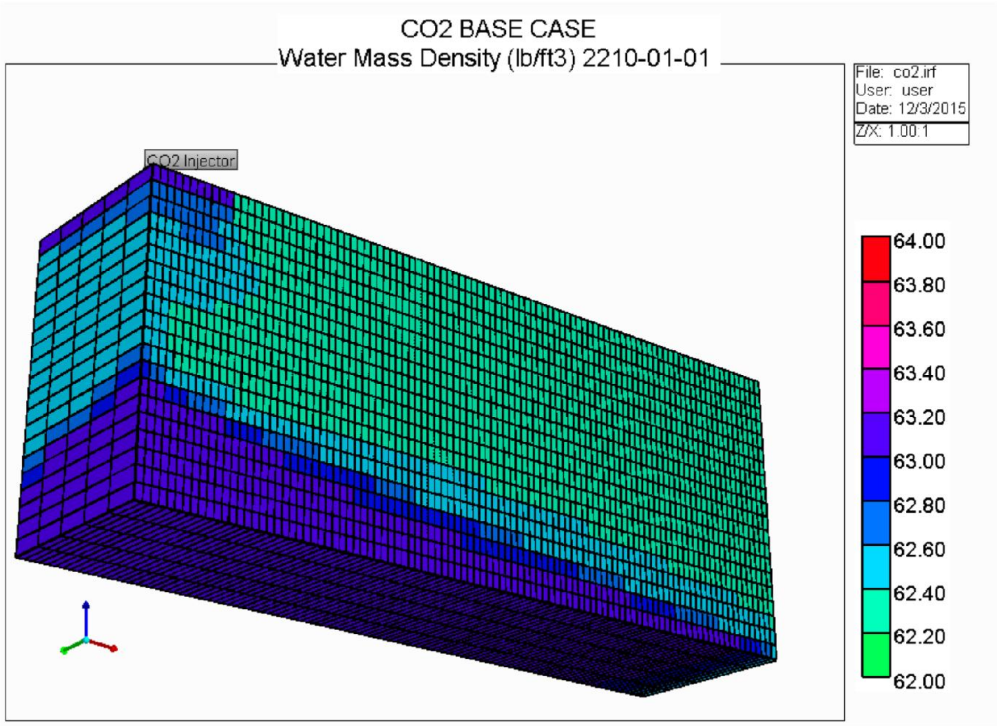

Fig (4.9): Water mass density after 200 years

4.3 Mineral trapping:

When the injected CO_2 dissolves in the aqueous phase, it reacts with the formation minerals and results in mineral precipitation. Three chemical reactions were defined in simulator.

Anorthite + $8H^+$ = 4 H_2O + Ca^{++} + $2Al^{+++}$ + $2SiO_2$

Calcite + H^+ = Ca^{++} + HCO^-_3

Kaolinite + $6H^+$ = $5H_2O$ + $2Al^{+++}$ + $2SiO_2$

The changes in mineral moles over time is shown in the figure below.

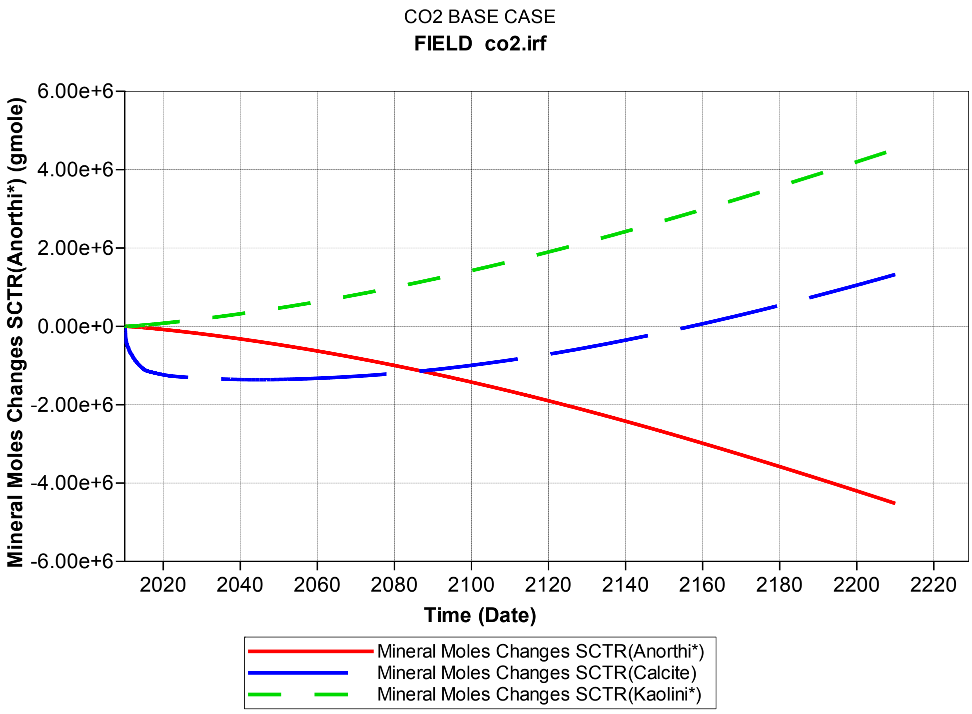

Fig (4.10): Mineral mole changes over 200 years

4.4 Reservoir pressure:

Reservoir pressure is very important parameter to consider throughout any injection process. However, for CO_2 sequestration monitoring the reservoir pressure is very essential for the following reasons:

1. Fracturing the formation and damaging the reservoir
2. Fracture the cap rock and open scape way for CO_2 and violate the whole process.

Due to the above reasons reservoir pressure was carefully monitored throughout the process, the average initial reservoir pressure was 1850 psi. After the injection period the average reservoir pressure raised to 4200 psi which was the peak. However, the formation fracture pressure is 4500 psi which is 300 psi higher than the average reservoir pressure after the injection.

The figures below show the reservoir pressure after the injection period and after 200 years.

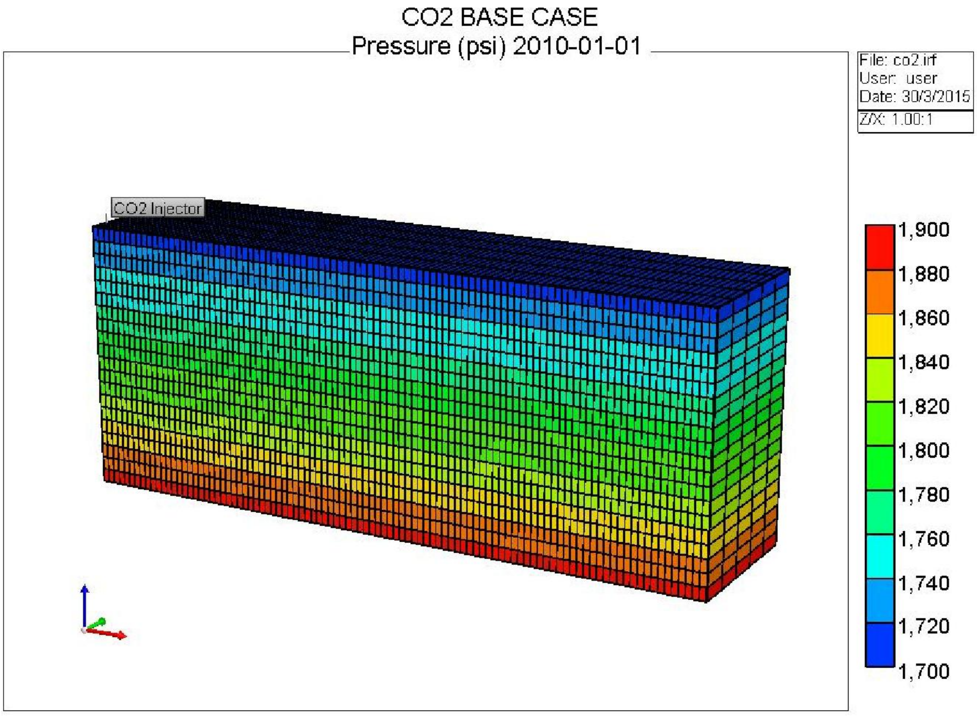

Fig (4.11): Initial reservoir pressure

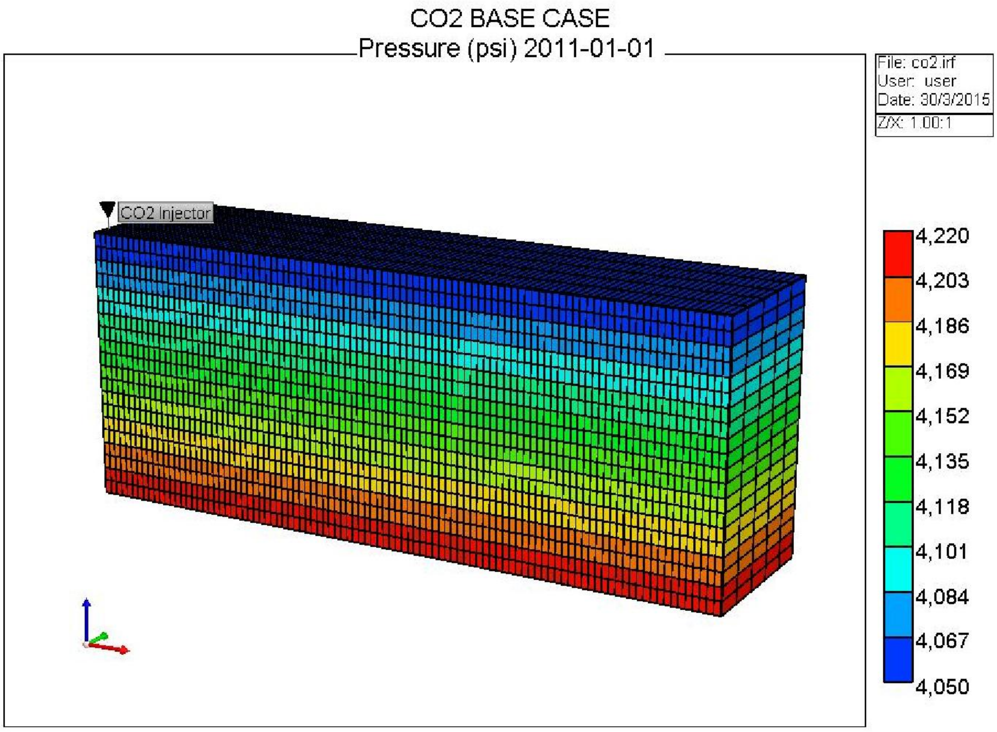

Fig (4.12): Reservoir pressure after the injection period

4.5 Summary of the base case

At the end of the injection period 2 PV (365 MMCF) of CO_2 has been injected into the reservoir. The average reservoirs pressure at the end of injection period was 4218 Psi while the formation fracture pressure is 4500 Psi which indicates that we are operating below the formation fracture pressure. After 200 years 48.94% of the injected CO_2 is a free gas in its supercritical state which is trapped by the cap rock. Furthermore, 37% trapped as residual gas and 14% dissolved in the water, while .06% present in mineral precipitate.

4.6 Profile study

In order to come up with most suitable reservoirs for CO_2 sequestration, several runs has been performed by changing one parameter while keeping the others unchanged.

The KH (permeability thickness) product is one of most important parameters that has to be considered. By changing the permeability and keeping the thickness constant we can see the effect of the product KH on the trapping of CO_2.

The permeability has been changed for all direction as 100mD, 200mD, 300mD and 400mD. The figure below shows the changes in the amount of CO_2 dissolved in the water with different permeability values.

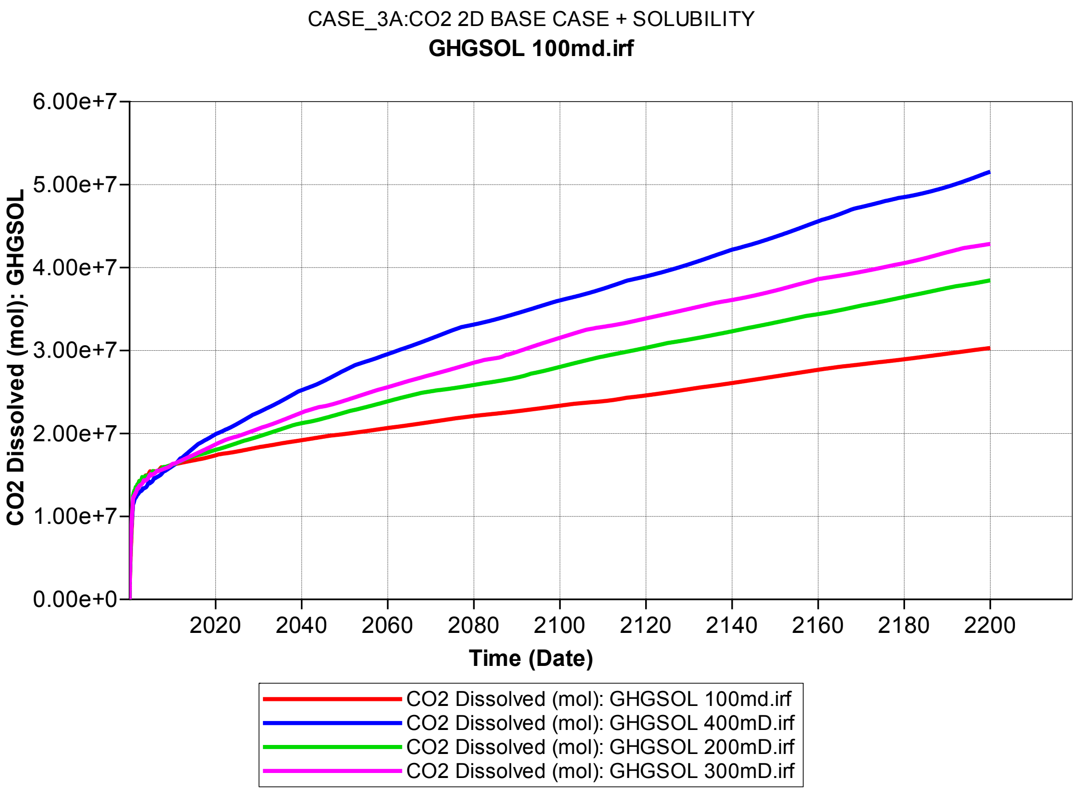

Fig (4.13): CO2 dissolved with different permeability values

It has been observed that the higher the permeability the more amount of CO_2 will dissolve in the water. When there is a higher permeability it means higher Injectivity and therefore, larger amount of CO_2 in contact with the water. For lower permeability, we have low Injectivity because the simulation includes a maximum bottom hole pressure of 4200 psi which limits the amount of CO_2 injected. Thus, less CO_2 stored in the reservoir when formation permeability is small.

The reservoir temperature plays a big role in controlling the amount of CO_2 dissolved in the water. Therefore, the temperature has been changed for four values in four different runs, which are 100°F, 150°F, 200°F and 250°F. The figure below shows the changes.

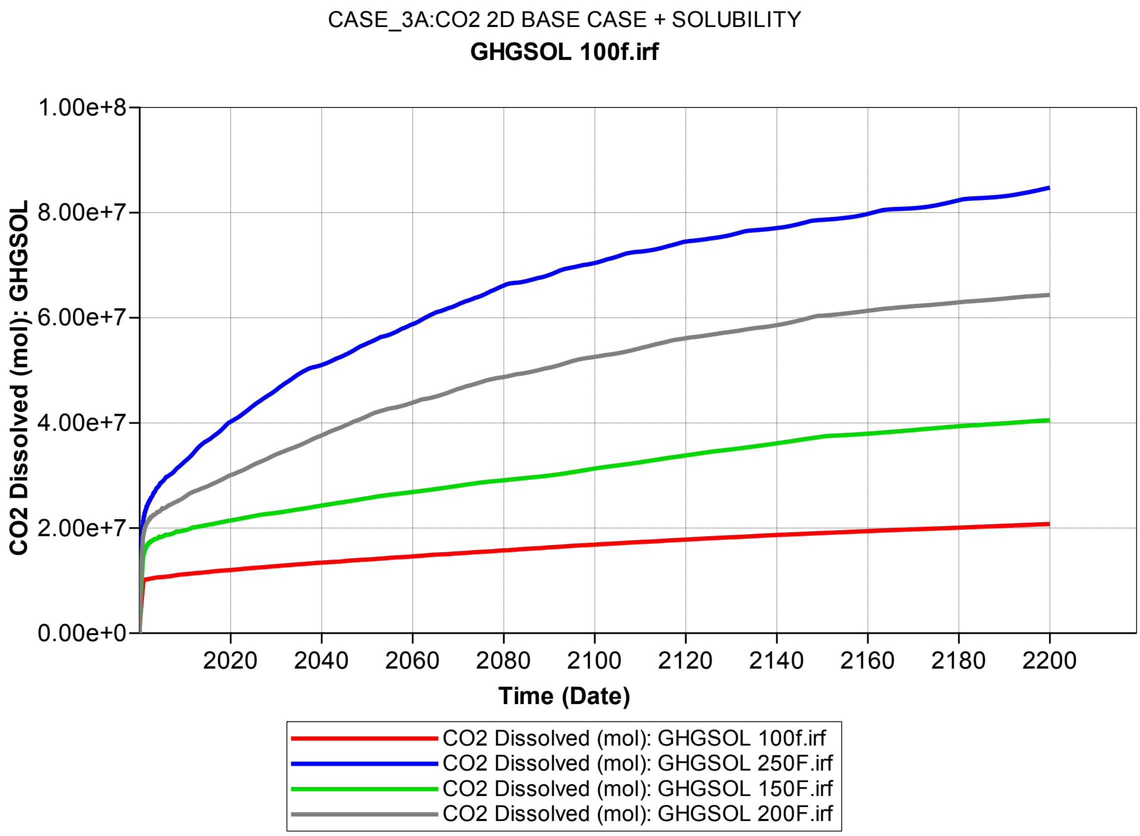

Fig (4.14): CO2 dissolved with different reservoir temperature values

As shown in the above figure, high temperature reservoirs are preferable. The solubility of CO_2 increase with the temperature. The oil reservoirs in Malaysia have a relatively high temperature which make them suitable for CO_2 sequestration.

Salinity of the water also has an impact on the solubility of CO_2 as shown in the figures below three cases has been run with three different values of salinity which are 10,000ppm, 50,000ppm and 200,000ppm.

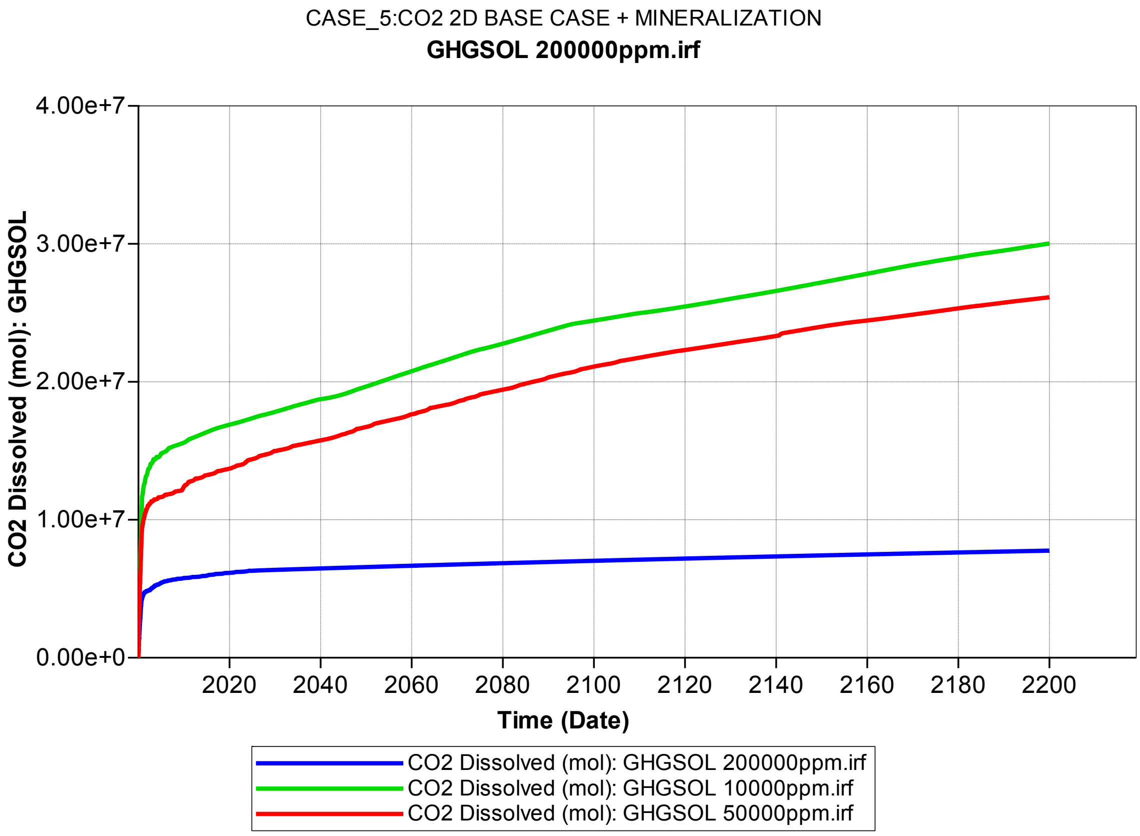

Fig (4.15): CO2 dissolved with different water salinities

As the figure showing the more saline the water, less CO_2 will dissolve in the water. On the other hand it has been found that the amount of NaCl dissolved in the water has an impact on the chemical reactions which leads to perception of minerals. The more saline the water, the higher the mineral precipitation. The figure below shows the results.

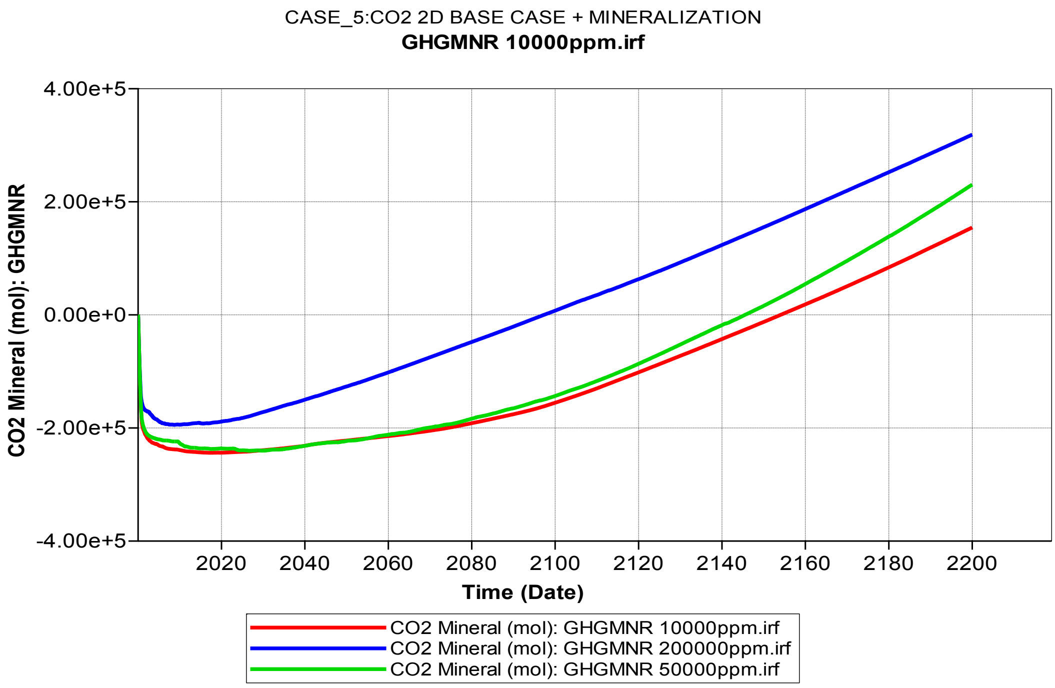

Fig (4.16): CO2 mineralized with different water salinities

4.7 Profile study summary:

The table below summarize the sensitivity analysis

Parameter Varied	Variations	Effects
Permeability	100mD	Increase in the average formation permeability increases the amount of CO_2 stored and therefore the CO_2 dissolved.
	200mD	
	300mD	
	400mD	
Temperature	100°F	The higher the reservoir temperature the more amount of CO_2 will dissolve in the water.
	100°F	
	100°F	
	100°F	
Salinity	10,000ppm	Increase in the water salinity decreases the solubility of CO_2 in the water. While exhibit an increase in the amount of CO_2 mineralized.
	50,000ppm	
	200,000ppm	

Table (4.1): sensitivity analysis

Chapter 5

Conclusion and Recommendations

Conventionally, and in most of the CCS projects CO_2 is injected into deep saline aquifers which has high potential for sequestration. However, it might have high operational cost because the aquifers are very deep. Whereas, in this project the watered-out reservoirs will be utilized to store CO2 since it is found in a shallow depth compared to the deep saline aquifers, and it can store CO_2 for long term as stated in our hypothesis.

Two pore volumes of CO_2 has been injected and stored successfully for long term. The residual and structural trapping has been studied as well as the solubility trapping. The mineral reactions has been defined and furcated for 200 years.

After 200 years around 48.94 % of the injected CO_2 remained in its supercritical state, 37 % trapped as residual gas, 14% dissolved in the water and 0.06% present in mineral precipitate. The CO_2 molecules dissolved in the water and present in mineral precipitate are subjected to increase with time.

The higher the reservoir permeability the more CO_2 will be stored, also it has been found that the solubility of CO_2 increase with the temperature. Moreover, the solubility of CO_2 in the water decreases with increase of salinity. However, the more saline the water the more chemical reactions will take place which eventually result in mineral precipitate.

Recommendations for future work

- Use heterogeneous reservoir.
- Try different reservoirs with different depths and different water aquifer.
- Estimate the economic cost of the project.

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Appendix

Appendix 1: the amount of CO_2 injected and trapped

```
1
        ******************************************************************************
        *  Well Summary at Reservoir Conditions at 7.3049E+04 days (2200 JAN. 01) *
        ******************************************************************************

 Well                                          BHP       Oil Rate     Gas Rate    Water Rate   O-G-W Rate    BHP-Pblock
  No.    Name       Type      Block            kpa        m3 /d        m3 /d        m3 /d        m3 /d         kpa
 ----  --------   -------    -------       ----------   ----------   ----------   ----------   ----------   ----------
   1   CO2_INJE   SHUT IN WELL

 Cumulative Field Total at Reservoir Conditions for Components.......................................

 Comp          Cum Inj        Cum Prod       Accum       Acc/(Inj-Pro)     Recovery        Error
                gmole          gmole         gmole                           %        mol in place,%
 --------    -----------    -----------   -----------    -----------    -----------    -----------
 CO2         1.28142E+08    0.00000E+00   1.28150E+08    1.00006E+00    0.00000E+00    6.22940E-03
 CH4         0.00000E+00    0.00000E+00   0.00000E+00    1.00000E+00    0.00000E+00    0.00000E+00
 H2O         0.00000E+00    0.00000E+00   3.15556E+05    1.00000E+00    0.00000E+00    3.17868E-03


 Total Cum Inj, mol   =  1.28142E+08            Ave. Acc/(Inj-Pro)          =  1.00002E+00
 Total Cum Prod, mol  =  0.00000E+00            Ave. Error, % mol in place =  3.13603E-03
 Total Accum, mol     =  1.28465E+08

        CO2 Storage Amounts in Reservoir             Moles          kg
            Gaseous Phase                       = 0.00000E+00   0.00000E+00
            Liquid Phase                        = 0.00000E+00   0.00000E+00
            Supercritical Phase                 = 9.91536E+07   4.36375E+06
            Trapped Sg < Sgc / Hysteresis       = 7.53335E+07   3.31543E+06
            Dissolved in Water                  = 2.92610E+07   1.28778E+06

 Mole Percent Hydrocarbon Recovered: Total-HC-Prod/Total-HC-Orginally-In-Place =     0.0000

 Field Total Prod/Inj Summary at Reservoir Conditions for Phases.....................................
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