NUMERICAL INVESTIGATION OF THE EFFECT OF CARBON SEQUESTRATION IN THE WATER ZONE OF A HYDROCARBON RESERVOIR

A THESIS SUBMITTED TO THE INSTITUTE OF GRADUATE STUDIES
OF
NEAR EAST UNIVERSITY

By
RACHEL NENDI GOLAU

In Partial Fulfilment of the Requirements
for the Degree of Master of Science
in
Petroleum and Natural Gas Engineering

NICOSIA, 2021

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Approval of Director of Institute of
Graduate Studies

Prof. Dr. K. Hüsnü Can BAŞER

We certify that this thesis is satisfactory for the award of the degree of Masters of Science in Petroleum and Natural Gas Engineering

Examining Committee in Charge:

Prof. Dr. Salih SANER	Committee Chairman, Department of Petroleum and Natural Gas Engineering, NEU
Prof. Dr. Cavit ATALAR	Supervisor, Head of Department of Petroleum and Natural Gas Engineering, NEU
Assist. Prof. Dr. Süleyman AŞIR	Department of Materials Sciences and Nanotechnology Engineering, NEU

I hereby declare that all information in this document has been obtained and presented in accordance with academic rules and ethical conduct. I also declare that, as required by these rules and conduct, I have fully cited and referenced all material and results that are not original to this work.

Name, Last name: Rachel Nendi GOLAU

Signature:

Date: 31st August, 2021

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To my Family…

ABSTRACT

Increasing amounts of greenhouse gases in the atmosphere calls for more methods of carbon sequestration to be implemented. Many forms of geological carbon sequestration exist including injecting carbon dioxide into mature hydrocarbon reservoirs, oil and shale reservoirs, coalbeds that cannot be developed economically and in the aquifers of hydrocarbon reservoirs.

In this thesis, the sequestration of carbon into the water zone (also commonly referred to as an aquifer) of a hydrocarbon reservoir was analyzed. A reservoir model of the Ogharefe reservoir in Nigeria was created and run on CMG GEM (compositional simulation). Using this model, the possibility of injecting CO2 into the Ogharefe aquifer for sequestration was investigated. In addition to the sequestration, this thesis examined the possibility of additional incremental oil production as a result of this sequestration and the effect of temperature, pressure and permeability anisotropy on the success of this project. Finally, the fate of the carbon dioxide 225 years after the injection process was analyzed.

The results of this study showed that 39.36 Bcf of carbon dioxide could be sequestered in the Ogharefe aquifer and that this sequestration process could lead to incremental reservoir production. It was also seen that temperature and pressure had a directly proportional relationship to oil production while permeability anisotropy had an inversely proportional relationship to oil production.

Keywords: Carbon sequestration; Ogharefe field; CMG GEM; carbon injection into hydrocarbon aquifers; numerical simulation

ÖZET

Atmosferdeki artan sera gazı miktarları, daha fazla karbon tutma yönteminin uygulanmasını gerektirmektedir. Olgun hidrokarbon rezervuarlarına, petrol ve şeyl rezervuarlarına, ekonomik olarak geliştirilemeyen kömür yataklarına ve hidrokarbon rezervuarlarının akiferlerine karbondioksit enjekte edilmesi dahil olmak üzere birçok jeolojik karbon tutma biçimi mevcuttur.

Bu tezde, bir hidrokarbon rezervuarının su bölgesine (aynı zamanda akifer olarak da adlandırılır) karbonun tutulması analiz edilmiştir. Nijerya'daki Ogharefe rezervuarının bir rezervuar modeli oluşturuldu ve CMG GEM (bileşim simülasyonu) üzerinde çalıştırıldı. Bu modeli kullanarak, ayırma için Ogharefe akiferine CO_2 enjekte etme olasılığı araştırıldı. Bu tez, sekestrasyona ek olarak, bu sekestrasyon sonucunda ilave artımlı petrol üretimi olasılığını ve sıcaklık, basınç ve geçirgenlik anizotropisinin bu projenin başarısı üzerindeki etkisini incelemiştir. Son olarak, enjeksiyon işleminden 225 yıl sonra karbondioksitin akıbeti analiz edildi.

Bu çalışmanın sonuçları, Ogharefe akiferinde 39.36 Bcf karbondioksitin tutulabileceğini ve bu ayırma işleminin artan rezervuar üretimine yol açabileceğini göstermiştir. Ayrıca sıcaklık ve basıncın petrol üretimi ile doğru orantılı, geçirgenlik anizotropisinin ise petrol üretimi ile ters orantılı bir ilişkiye sahip olduğu görülmüştür.

Anahtar Kelimeler: Karbon tutma; Ogharefe alanı; CMG GEM; akiferlere karbon enjeksiyonu; sayısal simülasyon

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LIST OF SYMBOLS AND ABBREVIATIONS

Bbl: barrel

Bcf; Billion cubic feet

CO$_2$: Carbon dioxide

CSS: Carbon Sequestration and Storage

m^3: Cubicmeter

md: millidarcy

stb/day: Stock tank barrel per day

scf/day: Standard cubic feet per day

CHAPTER 1

INTRODUCTION

This chapter will present an introduction to the thesis topic: give some background information, state the problem which this thesis plans to address, the hypothesis upon which this thesis is based as well as the limitations of this thesis.

1.1. Background

From the year 1859 when the first oil well was drilled by Edwin Drake, till the present time, the petroleum industry has seen a lot of challenges and developed solutions to these challenges – in a kind of cycle that has led to the improvements and wide body of knowledge available in the industry.

One of such problems is an excess of greenhouse gases that are left in the atmosphere and cause global warming. According to Union of Concerned Scientists (2017), the primary cause of global warming is an excess of carbon dioxide in the atmosphere which happens when coal, oil or natural gas are burnt. From this definition, it is obvious that the petroleum industry plays a large part in this issue of global warming. Sengul (2006) reports that fossil fuel powered plants account for about one third of the carbon dioxide emission. It follows from these that finding ways to reduce the amount of carbon dioxide in the atmosphere is a huge step in reducing global warming. Since this is a huge source of environmental concern, many policies have been put in place in an attempt to reduce the carbon footprint of the petroleum industry. Although other non-greenhouse gases method of energy or cleaner energy are being developed, fossil fuels are still being used and will be used for a while. This is why reducing greenhouse gases is of utmost importance (Pagnier et al., 2005).

Reducing carbon footprints can be done by minimizing flaring, employing renewable energy when possible and implementing carbon capture and sequestration (CCS) methods. CCS includes capturing the carbon dioxide from the source of emission, transporting it and then depositing it in an underground geological formation. This underground geological formation could be in mature oil fields, unmineable coalbeds or in the water zone of hydrocarbon reservoirs. The focus of this thesis will be the sequestration of carbon in the water zone of hydrocarbon reservoirs.

The formation water present in the water zone of hydrocarbon reservoirs is commonly referred to as the aquifer and because of the saline nature of this water zone, these aquifers are sometimes called saline aquifers. Because of this, in the text the water zone of hydrocarbon reservoirs will be referred to as “saline aquifers”.

1.2. Thesis Problem and Importance of the Study

Because of the increasing issue of global warming, it is imperative to investigate methods of carbon sequestration. This thesis investigates one of such methods which is the sequestration of carbon in saline aquifers. To solve this thesis problem, it is important to check the feasibility of carbon injection in the aquifers, the limitations and possible increase in oil production as a secondary result of this process since there will be an increase in reservoir pressure.

Using the CMG GEM compositional simulator, a model was created to aid in this investigation. This model helped to understand the mechanisms of CO_2 injection in saline aquifers, the limiting factors of this process as well as the most favourable/unfavourable conditions so as to understand when this method can best be applied. The effects of various rock properties on the result of this injection process were also investigated. It is also important to note that CO_2 is relatively reactive and this reactivity could impede or facilitate this process. This was also taken into consideration. The impact of CO_2 injection in saline aquifers on the petrophysical properties of the aquifer rock was also be seen.

1.3. Hypothesis

If carbon dioxide is injected into saline aquifers in its supercritical form, certain physical processes occur such as solubility trapping and residual gas trapping which will influence carbon dioxide staying in the aquifer thereby creating a feasible method for carbon sequestration. Since an effect of this carbon injection is an increase in pressure, does this carbon sequestration produce a resultant increase in oil production as a secondary effect?

1.4. Structure of the Thesis

The first chapter introduces the thesis topic, gives some background information on CCS in saline aquifers as well as highlights the aim of the study. The second chapter presents an extensive review of past literature on carbon dioxide injection on saline aquifers. The third chapter shows the detailed methodology of the thesis – the reservoir model created to be run on CMG GEM, the production/injection constraints and the simulation run(s). Chapter four analyses the results of the simulation run and the fifth chapter gives conclusions and possible recommendations to improve the sequestration of CO_2 in saline aquifers.

1.5. Limitations of the Research

Since it was not possible to obtain production and reservoir data, the model characteristics was based on review of previous literature. This means that not all the required data was available and some values would need to be estimated. However, these values were made as realistic as possible.

A second limitation is the reliance on the results of the commercial numerical simulation without supporting the study with the results of a laboratory study. This of course places some limitation on the reliability of the results obtained but the results are still reliable to a reasonable extent.

CHAPTER 2
LITERATURE REVIEW

Carbon sequestration in saline aquifers is a subject which has been studied and tried to be improved upon over and over again. Although many ways of sequestering coal exist, saline aquifers are particularly interesting because of its abundance in the world. This chapter aims to explain carbon dioxide sequestration in saline aquifers in detail: the process, its benefits, challenges and limitations as well as a detailed review of publications of previous applications and considerations to be taken in the application of coal sequestration in saline aquifers.

2.1. CO_2 Sequestration

There are various ways by which carbon dioxide can get into the atmosphere. It could be natural (when animals exhale carbon dioxide as respiratory waste) or by human activities, during energy production like burning fossil fuels (USGS, 2019). Carbon dioxide just like other greenhouse gases such as water vapor, methane and nitrous oxide main the warmth of the earth by absorbing the energy from the sun and redirecting it back to the surface of the earth. When these greenhouse gases (GHG) increase however, it leads to excessive trapping of heat which causes global warming (as explained in Chapter 1) (Lamb, 2018).

2.1.1. Biological and geological CO_2 sequestration

Carbon sequestration, which is also called carbon sequestration and storage (CSS), is a process by which greenhouse gases are captured and stored either biologically or geologically.

Biological CSS occurs when carbon dioxide is stored in plants as well as in oceans and soils. Oceans absorb about 25% of carbon dioxide in the atmosphere annually and during photosynthesis, the plants take in carbon dioxide and release oxygen into the atmosphere, thereby reducing the amount of carbon in the atmosphere. Soils also sequesters carbon in the subsurface through plants during photosynthesis. Once the carbon is in the soil, the soil gradually depletes the carbon levels which leads to more room for carbon storage. With biological CSS methods, they are naturally occurring phenomenon that help to reduce

GHG in the atmosphere but biological CSS methods alone are not sufficient. Because of this, it is important to use artificial methods to sequester this carbon. This is done by geologic carbon sequestration.

Carbon can be geologically sequestered by injecting the captured carbon dioxide into deep sub-surface rocks for long term storage (Environmental Protection Agency, 2019). During geological CO_2 sequestration, there is the obvious effect of reducing the amount of greenhouse gases in the atmosphere but depending on the condition of the subsurface rocks that they are sequestered in, there could be additional benefits such as enhanced gas recovery (EGR) or enhanced oil recovery (EOR) leading to a win-win situation.

Considering that the emission and therefore the amount of GHG in the atmosphere has seen a steady rise, the amount of carbon that needs to be sequestrated is much more than it was in the past. Which means that the CSS projects are of a much larger scale than they were in the past and of course the technical issues are more challenging than they were in the past. Various guidelines and/or requirements are put in place depending on the location of the geological sequestration site to ensure that the carbon dioxide being geologically sequestered does not lead to further damaging of the environment by contaminating the underground drinking water. These guidelines are also put in place to ensure that the carbon dioxide stays in the subsurface for a long period. If the carbon dioxide escapes almost immediately after it is sequestered, it defeats the purpose of implementing this project.

2.1.2. The various forms of geological sequestration

In section 2.1.1, it was seen that during geological carbon sequestration, carbon is injected into underground geologic formations. These underground geologic formations include mature oil and natural gas reservoirs, oil and gas-rich shale beds, uneconomic coalbeds and deep aquifers saturated with brackish water or brine (Climate Change Connection, 2018) as shown in Figure 2.1. If geological carbon sequestration is to be successful, certain considerations such as the injection rate as well as the percentage purity of the injected carbon dioxide stream must be made (Barrufet et al., 2010). It has been seen in previous applications that these little details could mean the success or failure of a carbon sequestration project. For economic reasons, it is important to consider geologic sequestration activities together with improving oil recovery.

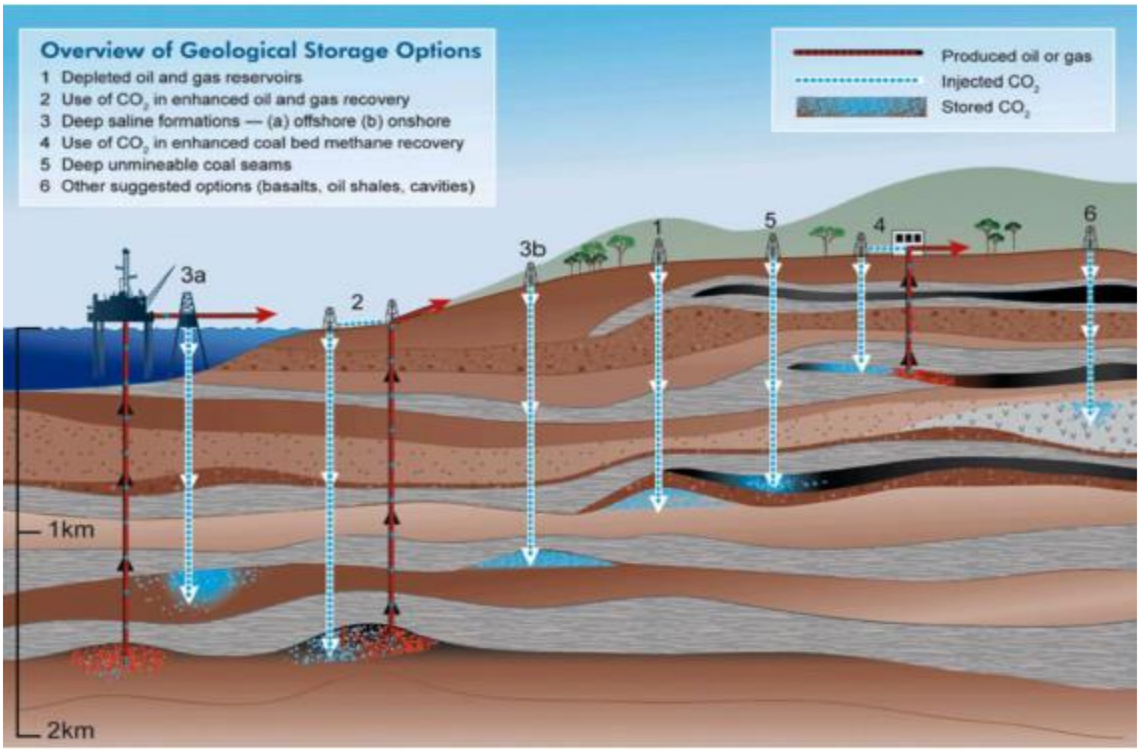

Figure 2.1: Various forms of geological storage (Indiania University Bloomington, 2018)

Various studies have been done on the sequestration of carbon in all the underground geologic formations listed above in an attempt to maximize the carbon storage potential of geologic formations. Carbon can be injected in mature oil and gas reservoirs as a method of re-pressurizing and/or flooding the reservoir and even for miscible injection in cases where the pressure of the reservoir is above the minimum miscibility pressure (MMP). An issue with this method is the unfavourable mobility ratio which leads to poor sweep efficiency, viscous fingering, early breakthrough and ultimately the reproduction of the injected carbon dioxide. When successful however, this method ensures removal of carbon dioxide from the atmosphere while simultaneously improving oil production. Barrufet et al. (2010) observed that depleted gas condensate reservoirs have a higher storage capacity than oil reservoirs or aquifers because of the high gas compressibility (up to 30 times the compressibility of oil under reservoir conditions). They also noted that by liquid revaporization and reservoir re-pressurization, these types of reservoirs allow for considerable EOR.

Oil and gas-rich shale beds with very low permeability have also been successful candidates for sequestration. Experiments have shown that shale has a preferential adsorption of carbon up to 5 times of methane which means there is both sequestration potential and incremental hydrocarbon production as a kind of EGR/EOR process (Kalantari-Dahaghi, 2010). It was seen in a numerical study that combining CO_2-EGR with re-fracturing treatments of horizontal wells in shale reservoirs gave much better results than ordinary re-fracturing treatments because the fracturing opened up more drainage area which leads to increased methane desorption. The study also noted re-pressurization of the shale formation as the main effect of CO_2-EGR in the shale formation (Eshkalak et al., 2014).

Similarly, CO_2-EGR can be applied to unmineable coalbeds in a process called carbon dioxide enhanced coal bed methane (CO_2-ECBM). It has been seen from previously published literature that this process is much more beneficial than conventional coalbed methane (CBM). Bergen et al. (2000) noted that the ratio of replacement of carbon dioxide molecule to methane molecule is 2:1 and 5:1 at depths of about 700m and 1500m respectively but beyond 2000m depth, increasing temperature and pressure places a limit on the coal methane content and reduces the coal seam permeability respectively. In a field application of carbon dioxide flooding in the Allison Unit of the San Juan Basin, it was seen that the ratio of injected carbon dioxide to produced methane was about 3.1:1.0 (Journal of Petroleum Technology, 2005).

Likewise, deep aquifers saturated with brackish water are good candidates for geological sequestration as various studies have shown. This is the main focus for this thesis and will be detailed in section 2.2. As a sort of modification of this process, Pilisi et al. (2012) and Pilisi et al. (2010) conducted feasibility studies on the process of sequestration in deep water sea beds. These studies showed that this is a viable option for carbon dioxide sequestration especially in places like Japan which are densely populated and carbon sequestration in aquifers would be difficult. These studies detailed the different processes and technology that are available and that should be available in order to successfully carry out this process and showed that at very great depths (>9400ft) the density difference between injected liquid carbon dioxide and seawater is a safer trapping mechanism than geological traps. It was also noted in this study that the possibility of hydrate formation at these conditions which lead to an even more secure trapping. This however is not within the scope of this thesis but it is important to note that variations of the carbon dioxide sequestration in saline aquifers have been made to adapt to different challenges and/or increase the amount of carbon sequestered.

2.1.3. The mechanisms of geological sequestration

For geological sequestration, displacement of in-situ fluids by carbon dioxide and dissolution of carbon dioxide into these fluids, as well as chemical reaction of carbon dioxide with minerals present in the formation are the processes by which it is achieved. Products that result from the chemical reaction of carbon dioxide with the formation's minerals could be desirable or undesirable. For example, (Ca, Mg) CO3 are desirable because they are non-toxic, not fluid so they do not migrate easily and are chemically stable. Although the displacement is the dominant mechanism initially, dissolution and reaction mechanisms become more dominant as time progresses (Sengul, 2006).

To put it simply, certain mechanisms are important for trapping injected carbon dioxide in geological formations. These include: seal trap, mineralization, solubility and phase trapping. These mechanisms and how they act as time progresses are shown in Figure 2.2 below.

Seal traps trap carbon dioxide as a gas or as a supercritical fluid just as it would trap hydrocarbon in conventional hydrocarbon reservoirs (Sengul, 2006). Since seal traps prevent the injected carbon from escaping into the atmosphere (almost immediately it is injected), in the early periods of sequestration, it is the most important mechanism. For this method to be effective, carbon dioxide should be stored in its supercritical phase. Hitchon (1996) showed that for a depth of 800m, the density of supercritical carbon dioxide is about 740kg/m^3, making it less dense than formation water. Because of this, the carbon dioxide continues to rise in the formation until it reaches an obstruction which in this case is the seal trap. Without this trap, it escapes to the surface and into the atmosphere which obviously defeats the purpose of this project.

Another trapping mechanism mentioned previously is mineralization which occurs when carbon dioxide reacts with the minerals in the formation to form stable, solid compounds. Examples of this process includes formation of calcite and adsorption of carbon dioxide on coal. This process makes the coal immobile which ensures that it stays in the formation but is a very slow process which limits its efficiency. Solubility trapping on the other hand, involves the dissolution of carbon dioxide into the reservoir fluids such as oil and/or water. When carbon dioxide dissolves in oil, it lowers the viscosity and swells the oil just like in miscible injection processes. When carbon dioxide dissolves in water on the other hand, it acidifies the groundwater which could be neutralized by mineralization, as seen previously. Solubility of carbon dioxide in formation fluids is largely dependent on the sweep efficiency of carbon dioxide injection, amount of viscous fingering present and well as formation heterogeneity. Although this process is quick, there is a limited about of dissolution of carbon dioxide in water that can occur (Sengul, 2006).

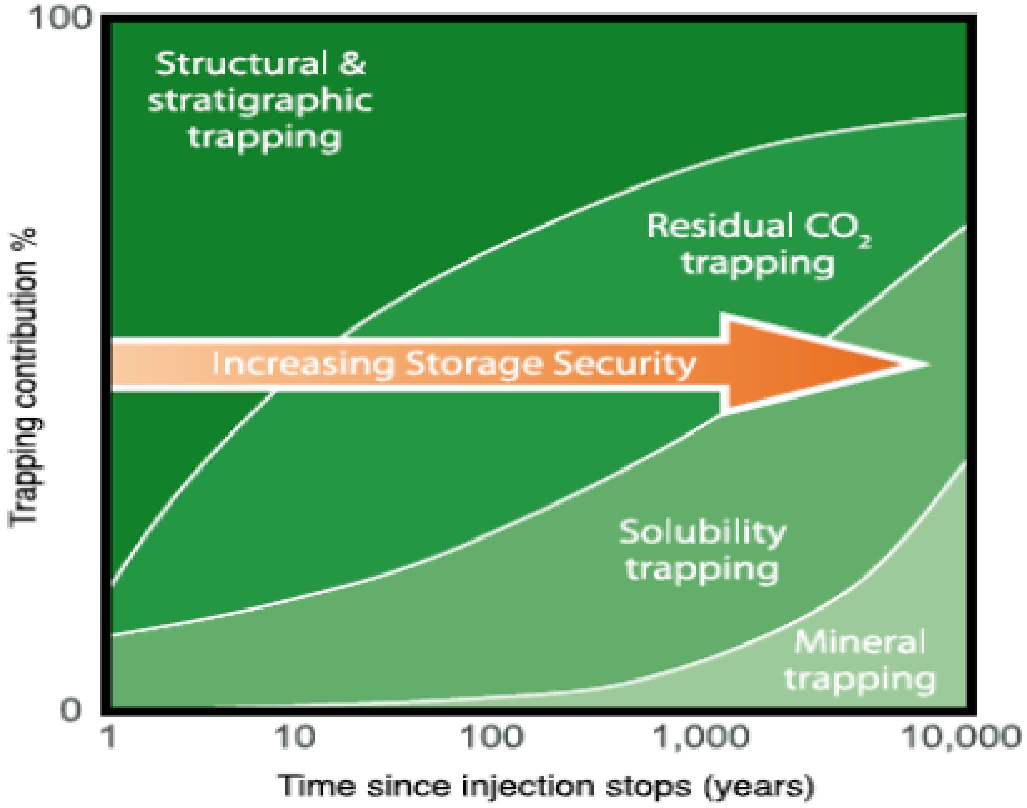

Figure 2.2: Trapping mechanisms in carbon dioxide sequestration processes and the time taken for effectiveness (Benson et.al., 2005)

The last trapping mechanism listed above is the phase trapping mechanism (also called the residual fluid trapping). This occurs when the relative permeability to carbon dioxide is 0. It involves retention of liquid or gaseous carbon dioxide in the reservoir pores as a result of hysteric relative permeability and capillary pressure effects. For example, injecting gaseous carbon dioxide into an aquifer followed by the influx of water creates a discontinuous immobile phase (Shariat et al., 2012).

2.2. CO_2 Sequestration in Saline Aquifers

Aquifers are underground bodies of porous rocks or sediments that are saturated with water and are able to move readily. Aquifers could be confined, that is the aquifer is exposed to the surface of the land, or unconfined, that is it has a confining layer that protects it from being exposed to the surface of the land. Porous rocks and sediments vary in properties/characteristics hence bodies of aquifers are not all uniform. Conventional reservoir properties and production constraints such as porosity, saturation, permeability, transmissivity, specific yield, presence of fractures and drawdown as well as composition of the aquifer rock all vary from one aquifer to another. For this reason, many considerations must be made when dealing with producing from an aquifer and injecting something into an aquifer.

2.2.1. Considerations to be made in carbon sequestration in saline aquifers

For this thesis, the sequestration of carbon in saline aquifers is studied. Various things make the process of sequestration in saline aquifers interesting. Aquifers are much more abundant than the other geological sites however, there is a limit to the amount of carbon that can be stored in these aquifers. In carbon storage in saline aquifers, the carbon is dissolved in these aquifers and the limit of this dissolution is the limit of the carbon storage which greatly limits the storage capacity of aquifers. And unlike other forms of geological sequestration like EOR/EGR processes where withdrawal of fluid is done at the same time, if fluid is not withdrawn from the reservoir while the carbon dioxide sequestration is being done, there is a build-up of pressure which has no way of getting released and this further limits the storage capacity of the aquifer. Schembre-McCabe et al. (2007) studied these limitations and found that injectivity could decrease due to interference from neighbouring injectors even in situations where there is unlimited storage capacity and due to injection of a low-mobility fluid such as carbon dioxide. The study also noted that injectivity of the carbon dioxide was best explained by mobility plots, that is lower mobility leads to lower injectivity and that even after stimulation operations are done in infinite-acting reservoirs, there is only a slight increase in injectivity since the area stimulated is a very small fraction of the total reservoir.

The phase behaviour of carbon dioxide from the surface and as it travels through the wellbore and into the aquifer must also be taken into consideration. The common practice is to inject supercritical carbon dioxide however, depending on the conditions of the aquifer it is possible for carbon dioxide injected as gas to turn to supercritical fluid in the reservoir. This can be seen in Figure 2.3 and 2.4 below. The critical point for carbon dioxide is 87oF and 1057psi. Below this critical point, when the carbon dioxide is in gaseous form, large storage volumes are required and the viscosity of the carbon dioxide is low which makes it very mobile. Above this critical point, the carbon dioxide becomes supercritical and acts like both a gas (viscosity) and a liquid (density). At these conditions, the mobility of the injected carbon is high and it does not take up too much storage space which is ideal. Depending on the conditions, the carbon dioxide could be denser than its gas form but lighter than water and therefore migrate upward or it could be denser than the water and sink to the bottom. Under normal conditions, the temperature and pressure at which the carbon dioxide becomes supercritical occurs at depths greater than 2600ft which makes the use of deep aquifers for sequestration advantageous. It was found by laboratory tests that although the interfacial tension between carbon dioxide and water decreased with increasing pressure and temperature, full miscibility between carbon dioxide and water was never achieved (Shariat et al., 2012).

A huge risk with carbon dioxide sequestration is the possibility of migration of the injected carbon dioxide into fresh water reservoirs which could pose health risks and is often a huge source of concern to the public. Other than migrating into freshwater, it is possible for this carbon to escape back into the atmosphere, defeating the purpose of the CSS project. In order to alleviate this concern, it is important to monitor the movement of carbon dioxide through the formation as time progresses. Monitoring, verification and accounting (MVA) techniques comprises of this monitoring process and giving public assurance. Rey et al. (2010) investigated the use of time-lapse seismic data as an MVA technique. The study successfully implemented time-lapse seismic data in reservoir characterization, reservoir model calibration, model behaviour prediction as well as reservoir monitoring for MVA by monitoring the movement of the carbon dioxide plume at various times in the reservoir by finding the location of the carbon dioxide front and linking it to the model's permeability and porosity. this study showed the reliability and feasibility of this method even in very large reservoirs.

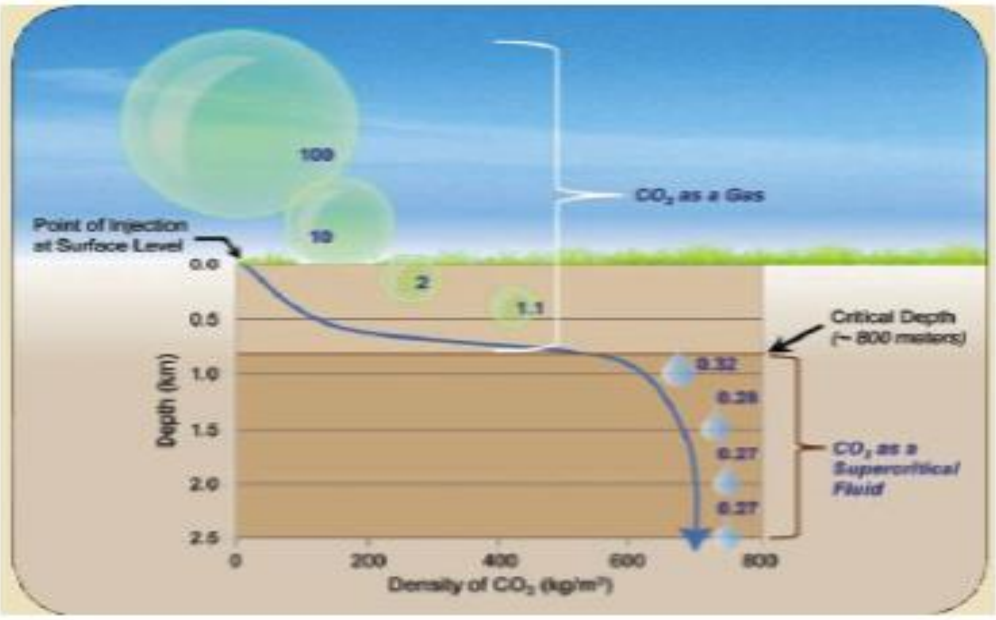

Figure 2.3: Phase behaviour of CO_2 under different conditions (National Energy Technology Laboratory 2010)

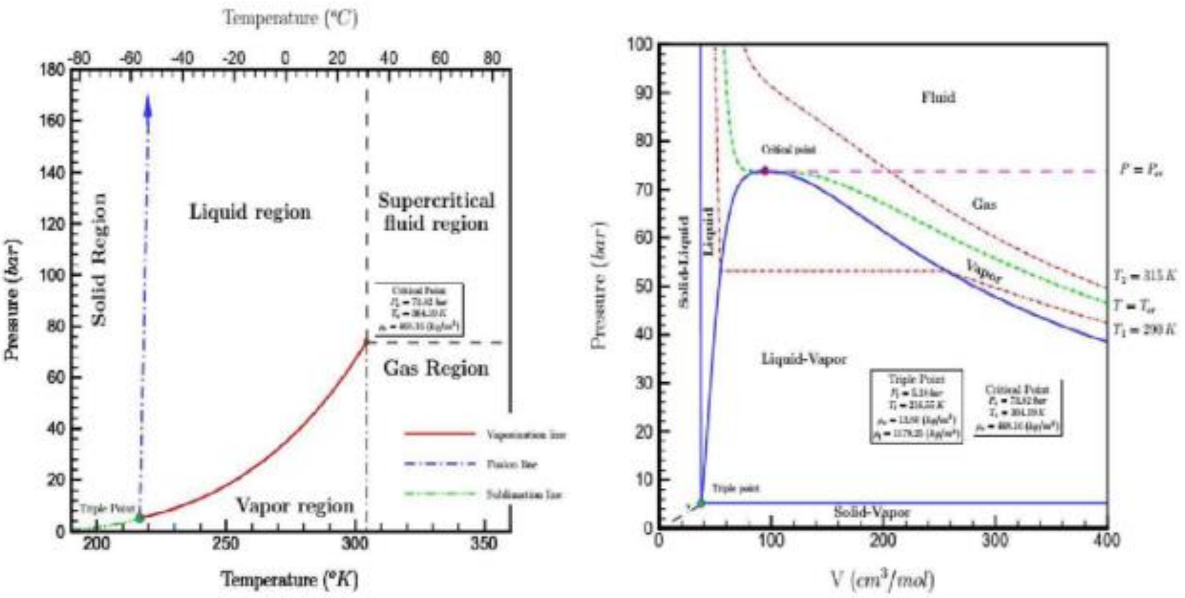

Figure 2.4: PVT properties of CO_2 (Benson & Cole, 2008)

Another consideration to be made in carbon dioxide sequestration processes is the integrity of the injection wells during the project life. As with any other project, proper preparation and planning must be done on both the reservoir and injection wells. Considering the vast amount of information present about miscible gas injection for EOR, gas re-injection as well as gas production, the CSS industry tends to assume it possesses adequate information about carbon dioxide sequestration wells. But the technical challenges associated with carbon dioxide sequestration wells greatly differ from those. Since carbon dioxide sequestration processes differ based on injection temperature, injection pressure, constraints, injected fluid composition and so on, these considerations must be made when designing the wells. Smith et al. (2010) highlighted the difference between injection well requirements for carbon dioxide sequestration wells versus miscible injection. Some key differences are: the difference in composition of supercritical carbon dioxide, higher temperatures and pressures in the wells in CSS projects, selection of higher integrity designs because well workover might be less acceptable in CSS projects, longer well service lives of carbon dioxide sequestration wells, much more minimal acceptable leak of CSS wells and the need for longer well integrity even after abandonment to ensure the success of the sequestration.

Furthermore, the efficiency of sequestration is highly dependent on injection parameters such as injection rate, injection duration as well as injection well orientation (Weir et al., 1996). The sweep efficiency of the carbon in the formation is also a huge determinant of the sequestration efficiency. From this, it follows that trying to maximize the impact of these parameters is key to maximizing the carbon sequestered. Tarrahi & Afra (2015) in an effort to improve the results of carbon dioxide sequestration, proposed a novel formulation to equalize the breakthrough time between equidistant cells therefore ensuring the uniformity of sweep efficiency during carbon sequestration operations in saline aquifers. By doing this, it was seen that there was an improvement in gas storage through increased trapping and dissolved gases in saline aquifers.

All these must be taken into careful consideration in CSS projects.

2.2.2. Enhancing trapping mechanisms of CSS in saline aquifers

As mentioned in Section 2.1.2, certain mechanisms are important for geological carbon dioxide sequestration. Depending on the conditions of the sequestration in a saline aquifer, it can be beneficial to tailor the specifications of the project to induce further trapping of the carbon dioxide. These can be especially useful in situations where the geological trap is not secure or is completely absent (Shamshiri & Jafarpour, 2012). Dirik et al. (2004) conducted an investigation of these mechanisms and their residual effects. The study found that increase in the solubility of carbondioxide means an increase in the formation water density, that an increase in salinity of the formation brine means an increase in its viscosity which leads to a decrease in mobility ratio and sweep efficiency. It was also seen from this study that higher pressures and salinity cause a decrease in brine compressibility which decreases the CO_2 storage capacity of the brine. Nghiem et al. (2009) attempted to induce further trapping of the CO_2 by placing a water injector above the CO_2 injector to enhance residual gas trapping and solubility trapping for both a low permeability aquifer and a high permeability aquifer. From this study, it was found that while this method causes a significant increase in the amount of residual gas trapping in low permeability aquifers, CO_2 trapping is not increased in high permeability aquifers. Another way to induce further trapping of the carbon dioxide is by brine injection to enhance mineral trapping as well as controlling the injection rate to mitigate carbon dioxide leakage.

2.2.3. Feasibility of CSS in saline aquifers

Many studies have been done to check the feasibility of applying carbon sequestration in saline aquifers in actual reservoirs. Temitope et al. (2016) conducted simulation studies to check the sequestration potential of a carbonate on-shore aquifer in UAE. These studies showed that dissolution trapping would be largely responsible for carbon sequestration and negative buoyancy at later times would enhance dissolution. It was also seen that due to density differences between the injected brine and CO_2, the supercritical CO_2 would migrate upwards but the presence of a seal geologically traps this CO_2 plume. Since the speed of plume migration is largely dependent on the trapping mechanisms, it is seen that since the results of the study show slow CO_2 plume migration, the trapping mechanisms are efficient. Therefore, this aquifer was seen to be a favourable candidate for carbon sequestration.

Temizel et al. (2017) and Temizel et al. (2018) also investigated this feasibility using a reservoir simulator by injecting carbon dioxide into an aquifer for 25 years after which it stopped and then run for 225 more years to observe what happens as well as what properties influence the outcome of this process the most. From the studies it was noted that with proper monitoring and implementation of the project, the process is feasible in the long term. It was also seen from these studies that properties such as the heat capacity of the surrounding rocks, rate of heat loss, rock density, geometry, thermal conductivity and salinity have a large impact on the outcome of the process.

Yang et al. (2010) compared the effects of heterogeneity and completion on carbon sequestration in both deep and shallow aquifers using CMG-GEM simulator. From this study, it was seen that favourable completion strategies for carbon sequestration are completion in all layers in vertical wells and completion in upper layers of horizontal wells. The study also observed that reservoir heterogeneity residual gas and solubility trapping as well as the spatial dissolution of CO_2, mean permeability affects the sequestration capacity of the formation as well as the injectivity with CO_2 injectivity being greatly influenced by permeability variation and sequestration capacity being more influenced by vertical to horizontal permeability ratio. Similarly, Oloruntobi & LaForce

(2009) conducted a laboratory study to investigate the effect of the degree of heterogeneity on the storage capacity in CO_2 sequestration. It was seen that lower permeability layers have higher trapping capacity while higher permeability layers have lower trapping capacity, that consolidated sands trapped more carbondioxide than the poorly consolidated sands, that as the air plume migrates upwards a decrease in the buoyancy drive is seen and that although the uniformity of the air front is dependent on the degree of heterogeneity of the reservoir, substantial amounts of air are trapped regardless of the degree of heterogeneity (about 40% of initial air volume).

2.3. Reservoir Simulation of CSS in Saline Aquifers

Barrufet et al. (2010) in a study on the comparison of carbon sequestration in saline aquifers and depleted condensate reservoirs noted that as expected, the amount of sequestrated carbon dioxide per pore volume was 1.60lb/ft3 for the aquifer model and 20.59lb/ft3 for the condensate model for equal model dimensions.

Just as with any other petroleum engineering project to be carried out, it is important to conduct enough investigations so as to properly understand the characteristics of the hydrocarbon reservoir and how best to develop that reservoir. Inadequate geological/reservoir information leads to inadequate planning of the carbon sequestration project to be done which would most likely result in a failed project or at best, a project that does not completely reach the sequestration potential that could have been reached if proper planning was implemented.

Therefore, it is essential to ensure that a reliable reservoir/geological model is created which accurately represents the properties of the reservoir, if the project is expected to be successful. This could be difficult in situations where the reservoir has a high heterogeneity or deformation caused by the presence of fractures and faults. Many approaches have been proposed to improve the quality of the final simulation model using in reservoir engineering calculations of saline aquifer. One of such is the analysis of the effects of faults and fractures in sandstone aquifers using the properties of the Navajo sandstone reservoir in Central Utah as a basis for testing (Pasala et al., 2003). This study showed that low permeability faults aid in vertical sweep of the carbon dioxide while the high permeability faults aids in horizontal sweep of the carbon dioxide and highlighted the importance of relative permeability in carbon sequestration. Knowing these distinctions between the impact of high versus lower permeability faults could prove very helpful in calibrating the model.

Seeing as carbon sequestration in saline aquifers is a complex process, studies have been done in an attempt to properly model many other complicated aspects of this process as well as measure the impact of certain effects. For instance, geochemical, geomechanical and thermal effects have been incorporated into conventional simulators. Geochemical reactions involve mineral dissolution/precipitation processes while geomechanics are important to model caprock failure and leakage to upper formations. Thermal effects are also important because they can affect the rate of the reaction in the reservoir (for example, dissolution). For example, parallel reservoir simulator was developed to model the transport and flow of CO_2 as well as the geomechanical processes associated with carbon sequestration in saline aquifers which gave results that agreed with previous studies done therefore proving that this method was viable (Winterfeld & Wu, 2011). Similarly, Tran et al. (2009) investigated the risk of CO_2 leakage caused by geomechanical effects of CO_2 sequestration in saline aquifers and presented a method for mitigating this risk. A fracture permeability model using the Brandon-Brandis approach was implemented to check the opening and closing of a crack in response to applied stress on the rock. The study noted that the injection gas temperature and injection rate can be tweaked to avoid CO_2 leakage as a result of cap rock failure. Zhang et al. (2007) also used a parallel simulator to investigate convective mixing as a result of marginal brine density increase when CO_2 dissolution occurs. It was seen that this parallel simulator properly captured the complicated results of this process. Han & Srinivasan (2015) also conducted a time-lapse simulation to investigate the geochemical effects of CO_2/brine mixtures in a siliciclastic reservoir in Mississippi using CMG-GEM simulator. This study showed that the dissolution/precipitation of the carbonate in the reservoir caused some changes in the reservoir rock structure which in turn affected the flow of the brine that was saturated with CO_2 and that care must be taken to consider this effect when creating models for CO_2 sequestration in saline aquifers because when carbonate facies are present, even in small amounts, it could be shown in the reservoir response at seismic scale. In another study, Nghiem et al. (2009) saw that conversion of CO_2 into carbonate minerals such as dolomite, calcite and siderite (otherwise called mineral trapping) takes place when aquifers have calcium ion, magnesium ion and iron ions over hundreds or thousands of years. The study also noted that coupling flow simulations with geomechanics calculations can be used in predicting the potential caprock failure and resultant leakage of CO_2.

Likewise, the effects of CO_2 sequestration on the petrophysical properties of an aquifer rock have also been studied in previously published literature. Ofori & Engler (2011) checked these effects in a compositional reservoir simulation study of a CO_2 sequestration project in a deep saline aquifer by injecting CO_2 for 10 years after which it was stopped and the fate of the reservoir was modelled for 1000 more years to study the impact of temperature, vertical to horizontal permeability ratio and salinity. It was found from this study that a proportional relationship exists between gas dissolution into brine and reservoir temperature, permeability and CO_2 migration as well as kv/kh and upward migration of gas while an inversely proportional relationship exists between salinity and gas dissolution into brine. Formation damage and its resultant reduction in permeability was also investigated as an effect of CO_2 sequestration in saline aquifers in an experimental and numerical simulation study on homogenous rock samples (Pink Desert limestone and Austin Chalk composed of mainly calcite) as well as on vug containing heterogenous samples (Indiana limestone and Silurian dolomite). This study showed that sodium sulfate present in the aquifer causes CaSO4 precipitation which is the primary cause of formation damage in homogeneous rocks and it was also seen that dolomitic rocks had higher damage as a result of higher reactions between carbondioxide and silicate minerals and that regardless of the homogenous/heterogeneous nature of the rock, the formation damage for high permeability cores is caused by the precipitation of reaction products and water blockage in low permeability cores. The study also noted that the Carman-Kozeny exponent and power exponent from 5 to 6 could be used to estimate permability change based on porosity change in homogenous caronate rocks. However, a larger exponent was needed for heterogeneous formations (Mohamed & Nasr-El-Din, 2012; Mohamed & Nasr-El-Din, 2013).

CHAPTER 3

METHODOLOGY

In this chapter, the methodology of the thesis will be explained. Details about the actual field to be used in performing simulations, the created reservoir model to be run on CMG, the model fluid and rock characteristics, well constraints and the characteristics to be changed in order to find the best condition for CO_2 injection in aquifers will be detailed. In order to perform this reservoir simulation, a reservoir model based on characteristics of the Ogharefe field in Nigeria is used.

3.1. The Ogharefe Field in Nigeria

The Ogharefe field in Niger Delta, Nigeria is operated primarily by Pan Ocean Oil Corporation (Nigeria) with some participation from the Nigerian National Petroleum Corporation (NNPC). The location of this field is shown in Figure 3.1. The field is an elongated anticline of about 2000acres with a northwest-southeast axis and is situated on the downthrown side of a major growth fault. By coring and the use of various well logs (gamma ray, spontaneous potential, resistivity, formation density and caliper), a cycle of barrier/beach, barrier front, marine clay and transgressive sand was seen to be the stratigraphy of this reservoir. The Ogharefe field was discovered in 1975 and production began in June 1976. There are seven zones in the reservoir but about 70% of reserves are in the B and C1 zones. The B zone of the reservoir is originally undersaturated with initial reservoir pressure at 4325 psia and a bubble point pressure of 3724 psia while the C1 zone was also initially undersaturated with an initial pressure of 4335 psia and a bubble point pressure of 3814 psia (Aron et al., 1984). The reservoir data for both major zones are shown in Table 3.1 below. These two zones will be the focus of the reservoir model created for this thesis.

The B sand unit is a complete deposition cycle that starts with a transgressive member and ends with a barrier bar. Examination of the core for this section showed a coarsening upward with relatively sharp contacts between the clay/sandstone barriers. Similarly, the C1 zone begins with a transgressive sand followed by a thin marine clay and finally a succession of barrier foot and barrier beach deposits. Coring also showed that the top of the unit showed limited coarsening upward but contacts between the lithologies are sharp (Aron et al., 1984). The net pay zone isopach for the B zone and the C1 zone are shown in Figure 3.2 and Figure 3.3 below.

Log data and well test data showed that the reservoir had an aquifer although the extent of the aquifer was not initially known. It was eventually known - using material balance calculations - that the aquifer radius was about 15 times the reservoir radius.

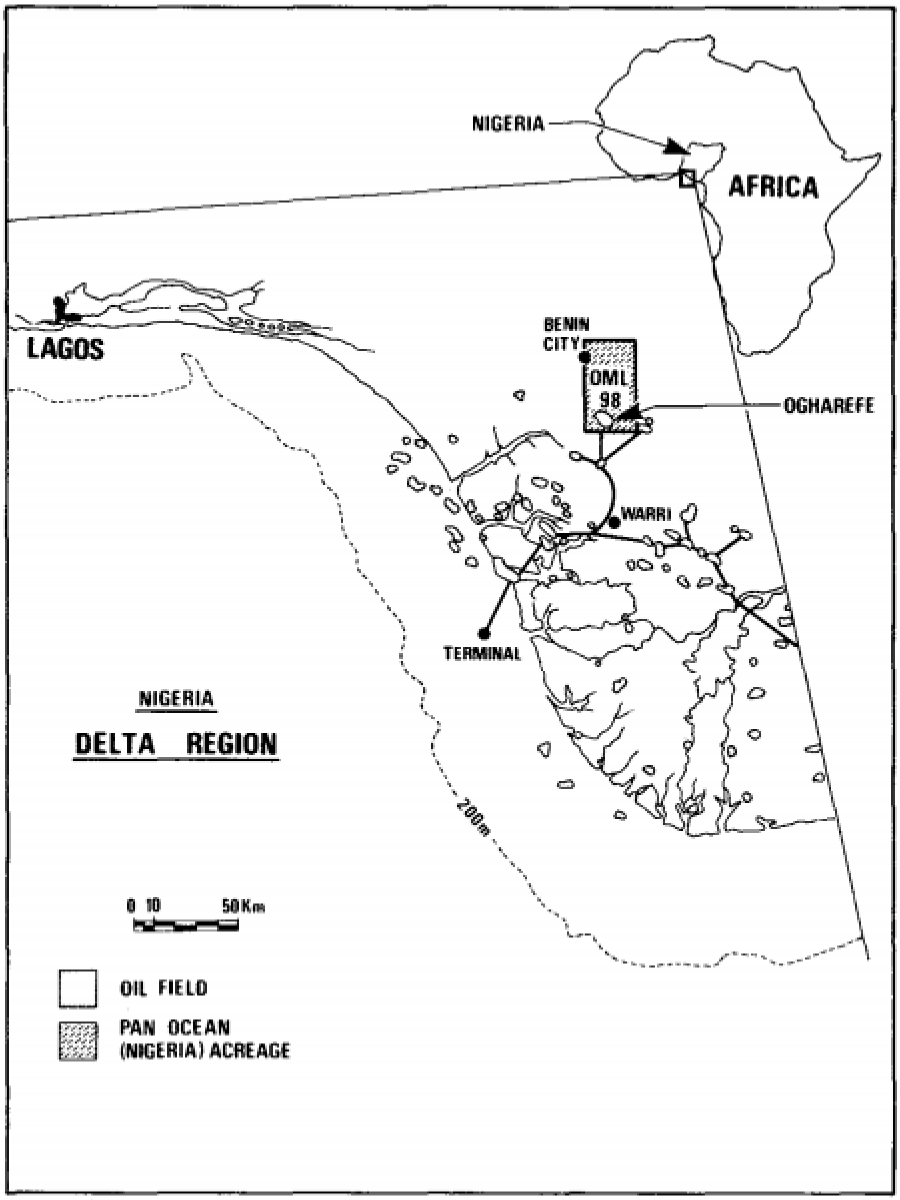

Figure 3.1: Location of the Ogharefe Field in Nigeria (Aron et al., 1984)

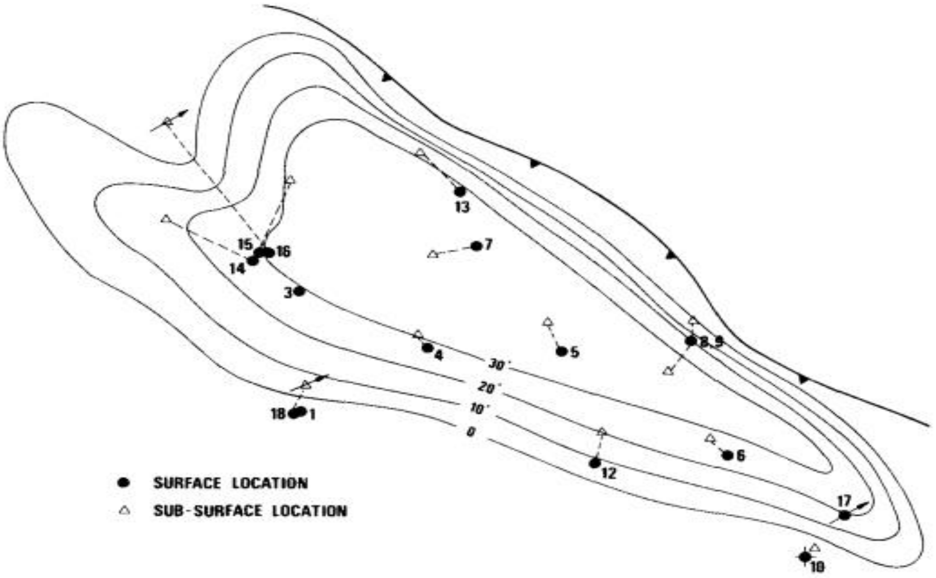

Figure 3.2: Net pay isopach map of the B zone (Aron et al., 1984)

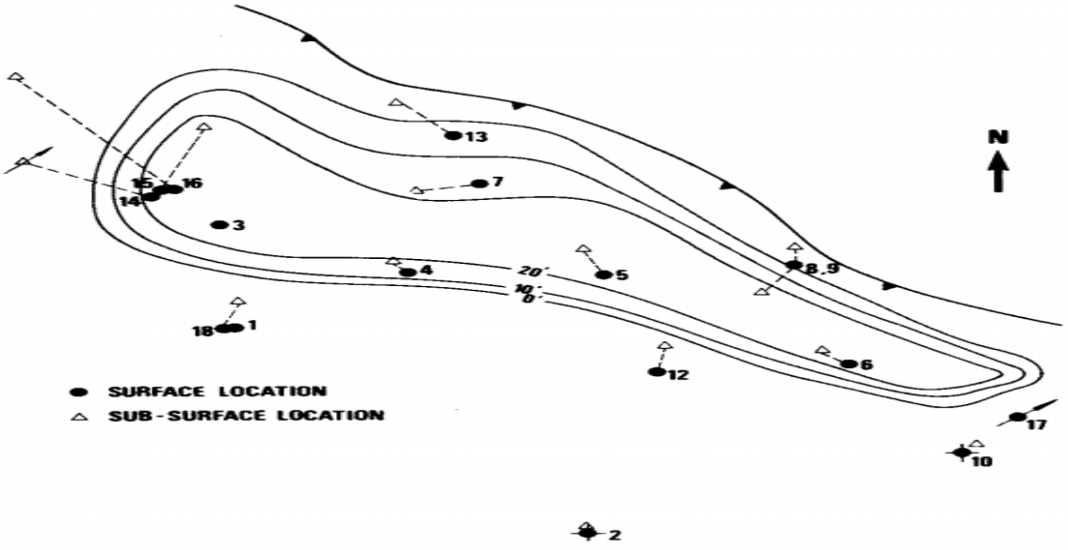

Figure 3.3: Net pay isopach map of the C1 zone (Aron et al., 1984)

Table 3.1: Reservoir data for B and C1 zones of the Ogharefe Field (Aron et al., 1984)

	PARAMETER	UNIT	Zone B	Zone C1
1	Reservoir depth	ft	9800	9825
2	Average porosity	%	23	21
3	Average permeability	md	575	450
4	Average water saturation	%	26	34
5	Initial reservoir pressure	psia	4325	4335
6	Bubble point pressure	psia	3754	3814
7	Original formation volume factor	RB/STB	1.845	1.767
8	Solution gas oil ratio	scf/STB	1542	1424
9	Initial oil viscosity	cp	0.18	0.22
10	Oil API gravity	^{o}API	46	45
11	Original OWC	ft	9800	9835
12	Original oil in place	MMSTB	36.3	15.9
13	Original gas in place	10^9 SCF	55.0	22.6

From the reservoir data in Table 3.1, it can be observed that since the pressures of these two zones are increasing with respect to increasing reservoir depth, they are in communication and as such are in different zones of the same reservoir

3.2. Model Characteristics

With the available reservoir data, it was possible to create a model of the Ogharefe sandstone reservoir on CMG GEM reservoir simulator. After a model was created it was modified to check for the optimal conditions for the sequestration of carbon in a saline aquifer. Reservoir characteristics such as temperature, pressure, permeability, vertical to horizontal permeability ratio and aquifer salinity were changed to find the optimal conditions for sequestration. This is the main focus of this thesis.

In order to make the simulation as accurate as possible, both heat loss as well as geochemical changes were modelled in the reservoir. The quantities used in determination of heat loss include a rock density of 145lb/ft3, rock heat capacity of 0.2 Btu/lbF and a rock conductivity of 2 Btu/ft.hrF

As can be seen in Figure 3.4 and Figure 3.5, it can be seen that the reservoir was made to be 3D: 15 by 15 by 6 grids. The first two layers represented the B reservoir, the third and fourth layers represented the C1 reservoir and finally, the aquifer was modelled in the last two layers. Care was taken to model this as closely as possible to the actual reservoir.

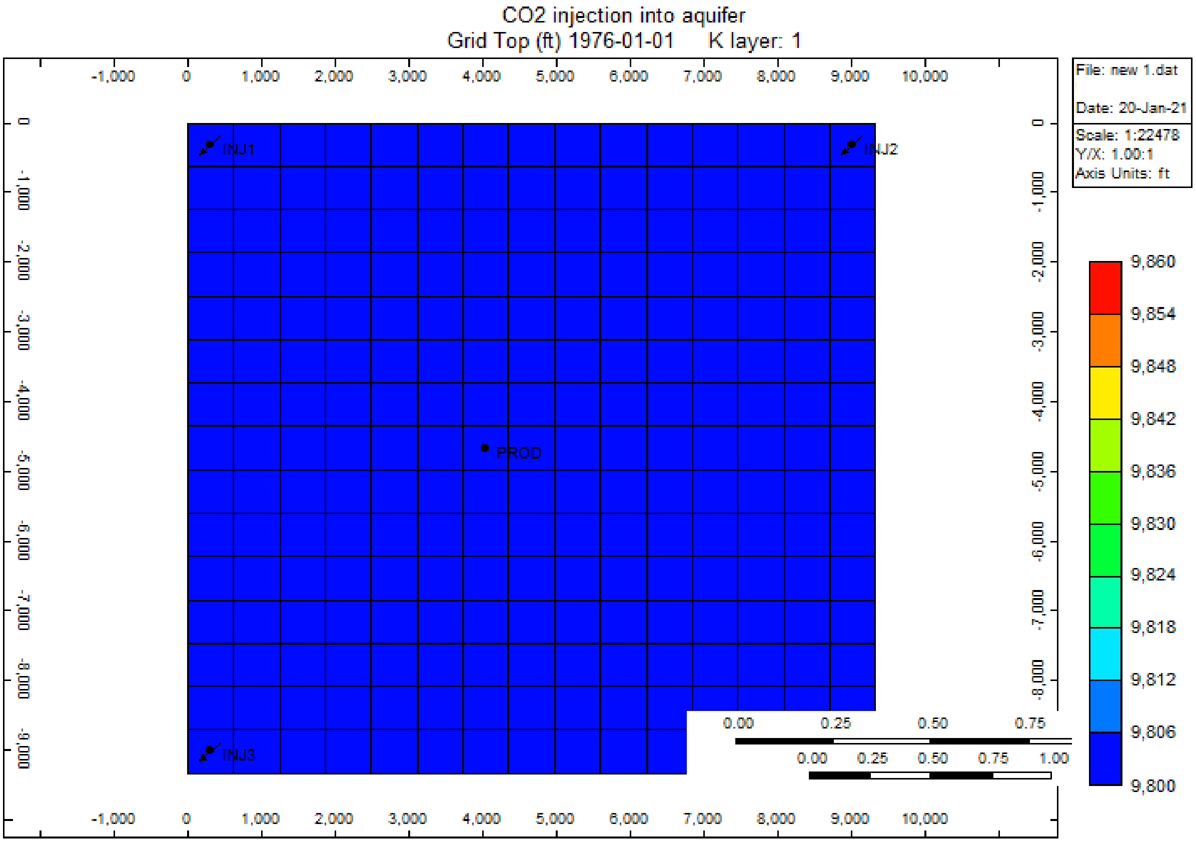

Figure 3.4: Top view of the reservoir model showing the depth to the top of the reservoir model (generated from CMG Builder)

The depth to the top of the reservoir was model 9800ft as shown in Figure 3.6 below. Because the different reservoir regions have different characteristics, care was taken to model the reservoir accordingly. For example, porosity and permeability varied along the z-axis of the reservoir.

From top to bottom the porosity values for each layer were: 0.23, 0.23, 0.21, 0.21, 0.15 and 0.15 as shown in Figure 3.7 below while the horizontal permeability values from top to bottom for each layer were: 850md, 300md, 450md, 450md, 1050md and 1050md as shown in Figure 3.8 below. Vertical permeability was set to be 10 times less than the horizontal permeability.

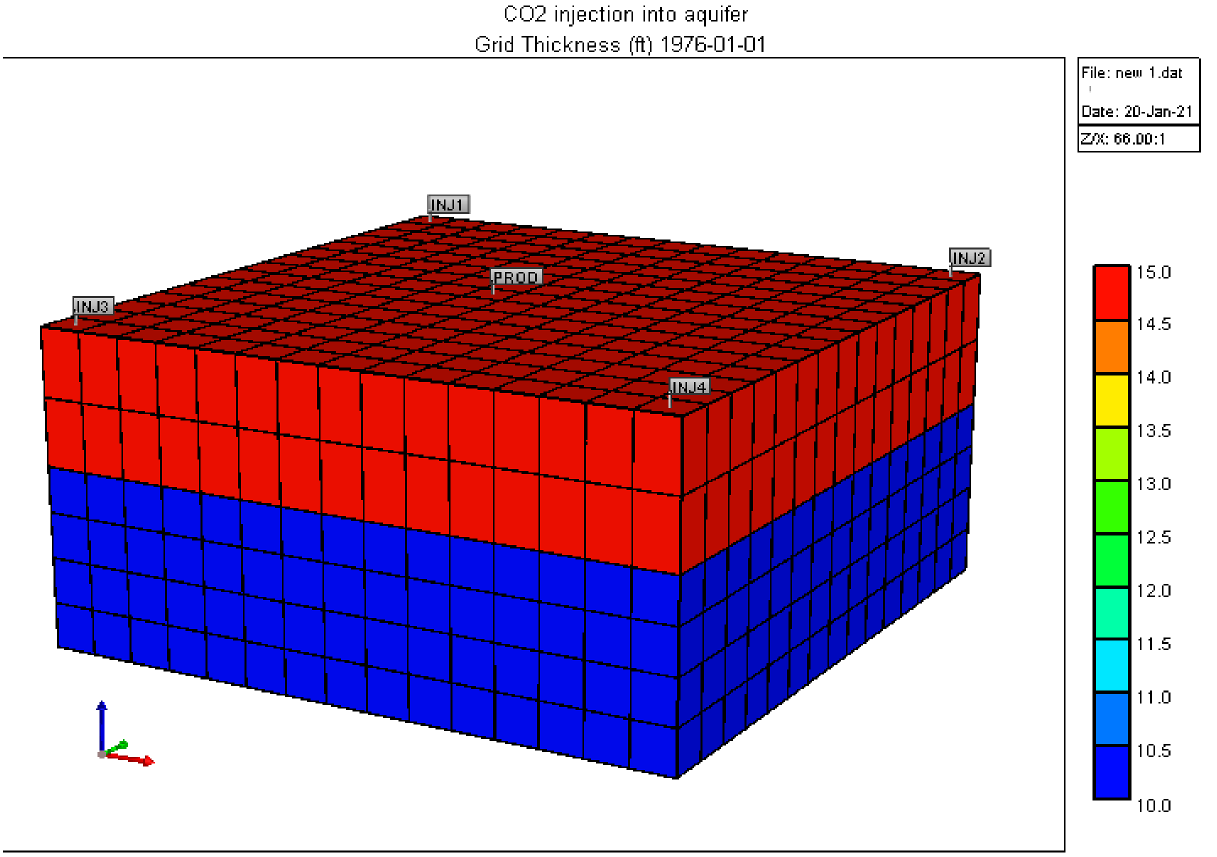

Figure 3.5: 3D view of the reservoir model showing variable depth thickness (generated from CMG Builder)

The aquifer was modelled to have an extent of 15 times the reservoir radius as was seen in the study by Aron et al. (1984). The reservoir rock compressibility was set to 5.8E-07 1/psi and the reservoir temperature was set to 212F. The brine salinity was set to 0.1 gmolNaCl / kg H2O. The water oil contact was set at 9850ft subsea depth.

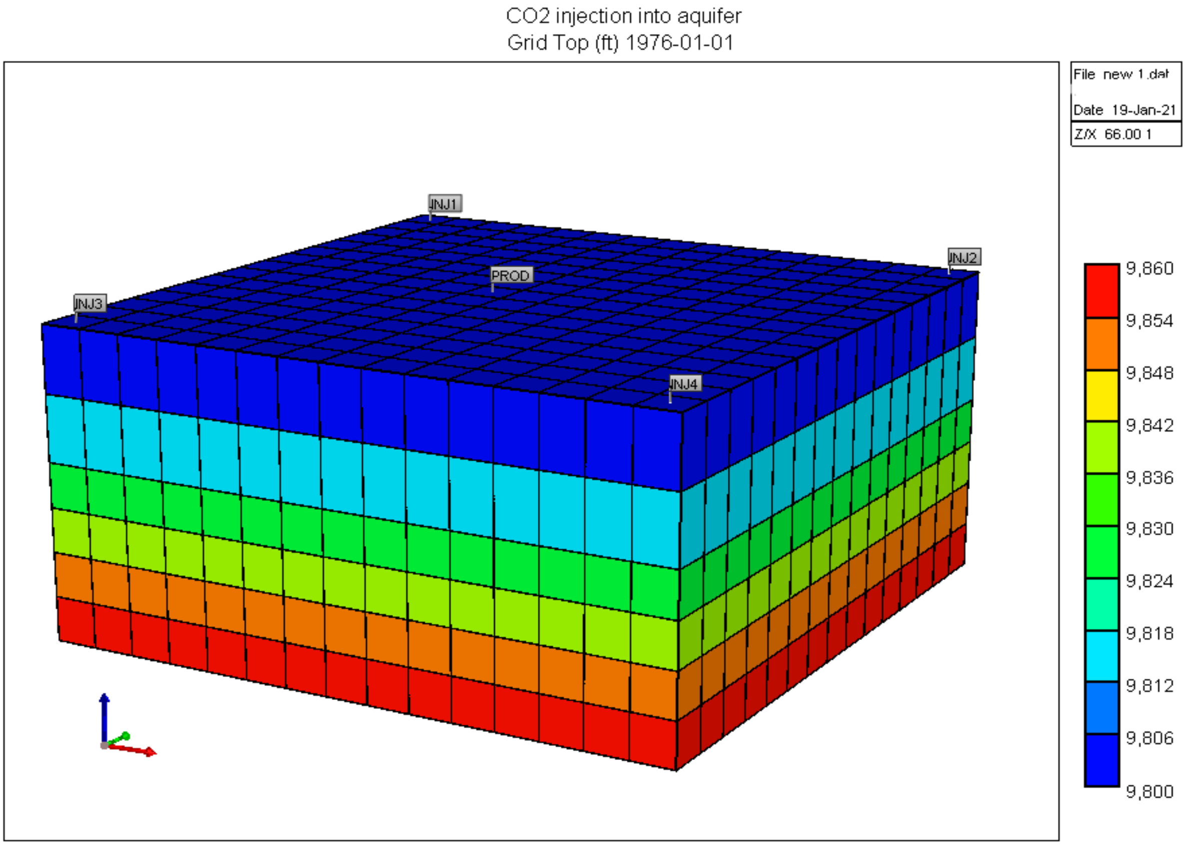

Figure 3.6: 3D view of the reservoir model showing the depth to the top of the reservoir (generated from CMG Builder)

There was one oil producer at the middle of the model and four injectors of carbon dioxide at the four corners of the model. Constraints of the wells in this model were tailored to maximize production from the reservoir. This reservoir was initially undersaturated and production well was constrained to a minimum bottom hole pressure of 3820psi in order to keep the reservoir above the bubble point pressure for both zones B and C1, and therefore prevent gas separating from the oil. The B and C1 regions of the reservoir were simulated with the characteristics in Table 3.1. Therefore, the reservoir model showed vertical heterogeneity in both rock and fluid properties. For this study, the aim of injecting CO_2

was not for secondary recovery (gas flooding) or tertiary recovery (miscible CO_2 injection). Instead, the carbon dioxide was injected into the aquifer for sequestration mainly and optimistically, a resultant increase in oil production as a result of pressure increase in the reservoir. Considering the nature of the injection project, the injection wells were perforated in the last two layers containing the saline aquifer while the production well was perforated in the first four layers to prevent excess water production.

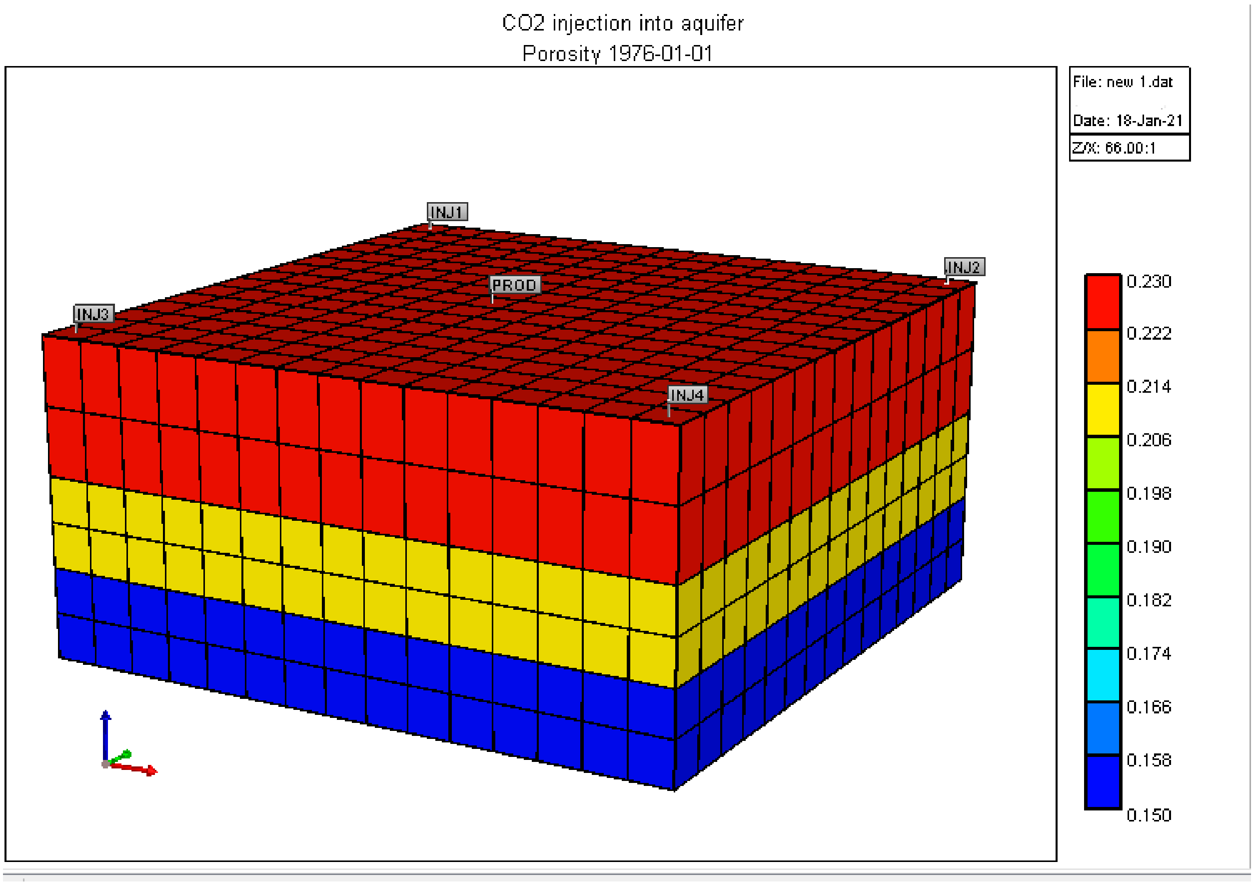

Figure 3.7: 3D reservoir model showing porosity variation along the z axis (generated from CMG Builder)

Finally, the simulation was run from 1st January, 1976 (when the field was actually put into production) to 1st January, 2225. The production plan was as follows:

- Oil production alone for the first 5 years (1st January, 1976 – 1st January, 1981)
- Oil production with simultaneous gas injection into the aquifer for the next 19 years (1st January, 1981 - 1st January, 2000)

- Shutting in all wells - no injection and production - for the next 225 years to see the fate of the reservoir after the injection process (1st January, 2000 - 1st January, 2225)

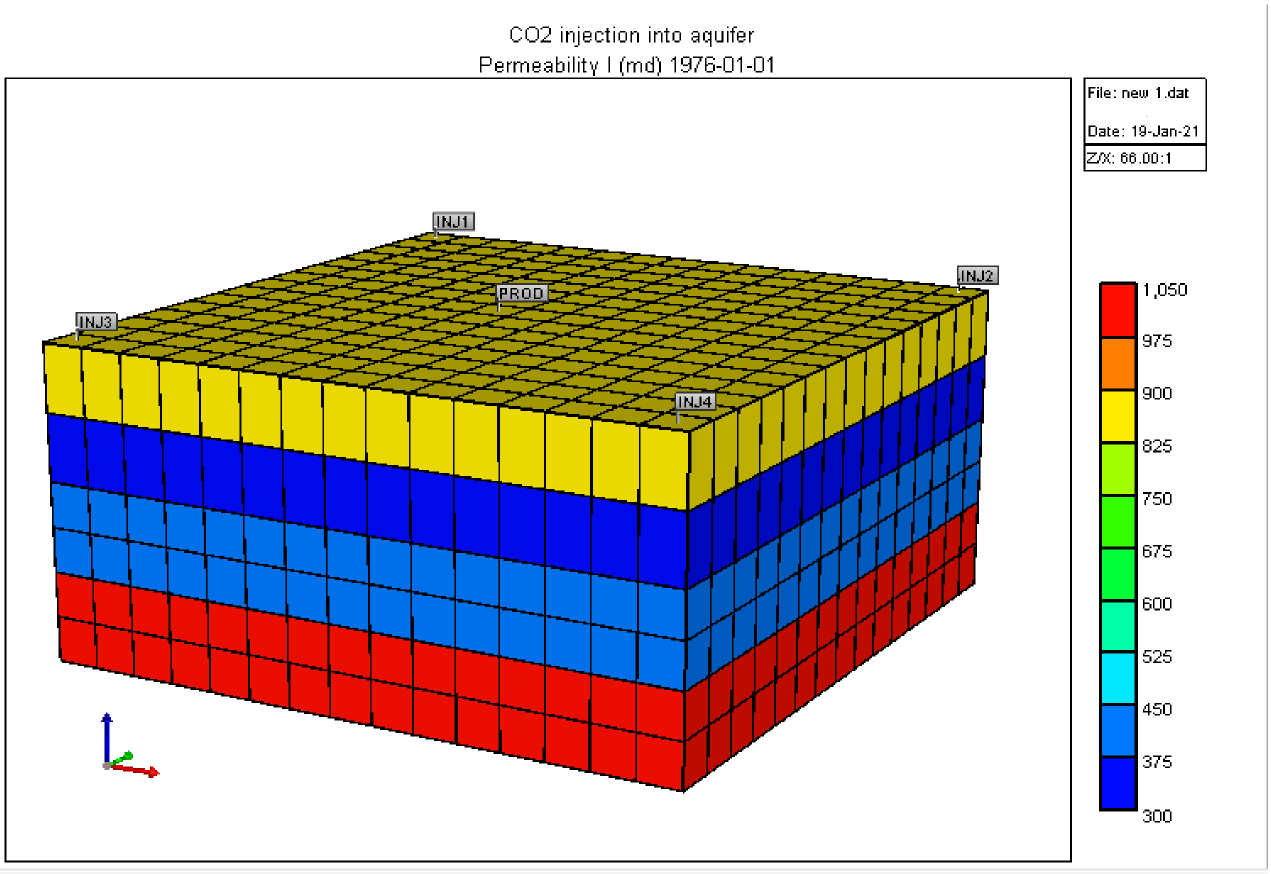

Figure 3.8: 3D reservoir model showing permeability variation along the z axis (generated from CMG Builder)

3.3. Modelling Geochemical Effects

As mentioned previously, the CMG GEM Compositional simulator was used to run this simulation. Therefore, it was possible to model the geochemical effects of this reservoir. This was a compositional simulation consisting of 7 components: ‘CO_2’, ‘N2 to CH4’, 'C2HtoIC4', 'NC4toC11', 'C12toC19', 'C20toC29' and ‘C30+'. In addition to these components, there were 10 aqueous components which were used in modelling geochemical effects of the carbon dioxide injection process in the aquifer. These includes hydrogen ion, ('H+'), calcium ion ('Ca++'), hydrocarbonate ion ('HCO3-'), magnesium ion ('Mg++'), sodium ion ('Na+'), chlorine ion ('Cl-'), hydroxide ion ('OH-'), calcium hydroxide ion ('CaOH+'), calcium bicarbonate ion ('CaHCO3+') and calcium carbonate ion ('CaCO3'). Finally, two mineral components were simulated: calcite and magnesite.

From Chapter 2, it was seen that the chemical reactions accompanying carbon dioxide injection into saline aquifer, affect the result of the sequestration process. For this reason, the geochemical processes in the reservoir were simulated as well using the aqueous components, the minerals, the carbon dioxide and the saline water. Equation 3.1, Equation 3.2, Equation 3.3, Equation 3.4 and Equation 3.5 below show the equations that were modelled in the simulator:

Formation of water with the hydrogen ion and hydroxyl ion:

$$\mathrm{H^+ + OH^- \rightarrow H_2O} \qquad (3.1)$$

Reaction of the calcium hydroxide ion with the hydrogen ion to form calcium ion and water:

$$\mathrm{CaOH^+ + H^+ \rightarrow Ca^{2+} + H_2O} \qquad (3.2)$$

Reaction of the calcium bicarbonate ion to form the calcium ion and bicarbonate ion:

$$\mathrm{CaHCO_3{}^+ \rightarrow Ca^{2+} + HCO_3{}^-} \qquad (3.3)$$

Reaction of the calcite with the hydrogen ion to form calcium ion and bicarbonate ion:

$$\mathrm{Calcite\ (CaCO_3) + H^+ \rightarrow Ca^{2+} + HCO_3{}^-} \qquad (3.4)$$

Reaction of the magnesite with the hydrogen ion to form magnesium ion and bicarbonate ion:

$$\mathrm{Magnesite\ (MgCO_3) + H^+ \rightarrow Mg^{2+} + HCO_3{}^-} \qquad (3.5)$$

.

CHAPTER 4

RESULTS AND DISCUSSIONS

After running the created CMG data file on CMG GEM, the results were extracted and analysed. This chapter will contain the analysis of these results.

First, a base case (case 1) was created to check the performance of the model after the CO_2 injection into the aquifer starts. Then, a sensitivity analysis was done to check the behaviour of the model when certain input variables are changed. The variables used for the sensitivity analysis in this study are temperature, pressure and vertical to horizontal permeability ratio. Finally, the fate of the CO_2 at the end of the simulation (after 249 years) is seen in terms of trapping mechanisms in the aquifer will be analysed.

4.1. Performance of the Base Case Reservoir Model

The base case model – which is named Case 1 – was used to check the performance of the reservoir in terms of oil production (majorly incremental oil production as a result of CO_2 injection into the aquifer), gas production and amount of carbon dioxide that can be sequestered in the aquifer.

Figure 4.1 below shows the cumulative oil production and oil rate with time for the production life of the reservoir model. It is important to note the sharp increase in oil production rate and simultaneous change in the slope of the cumulative oil production curve in the year 1981, which is the year at which the CO_2 injection into the aquifer begins. These show that if the CO_2 injection was not done, the amount of produced oil from the reservoir would be much less. The cumulative oil production was 1.316MMbbl with a peak production rate of 7000bbl/day from 1983 to 1984.

Similarly, Figure 4.2 below shows the cumulative gas production and gas production rate with time for the production life of the reservoir model. There is also a sharp increase in gas production as a result of carbon dioxide injection into the aquifer. The cumulative gas production was 9.137 Bcf at the end of the production with a peak at 4.892 MMSCF/day at 1983.

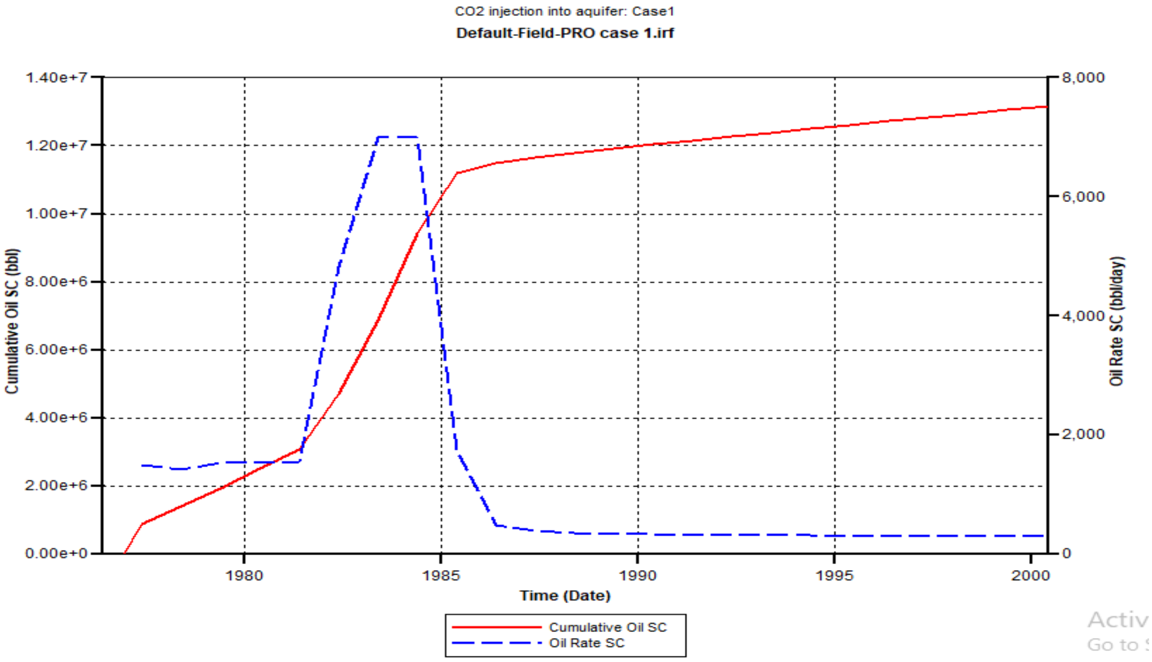

Figure 4.1: Cumulative oil production and oil production rate for the production life of the reservoir model (generated from CMG Results Graph)

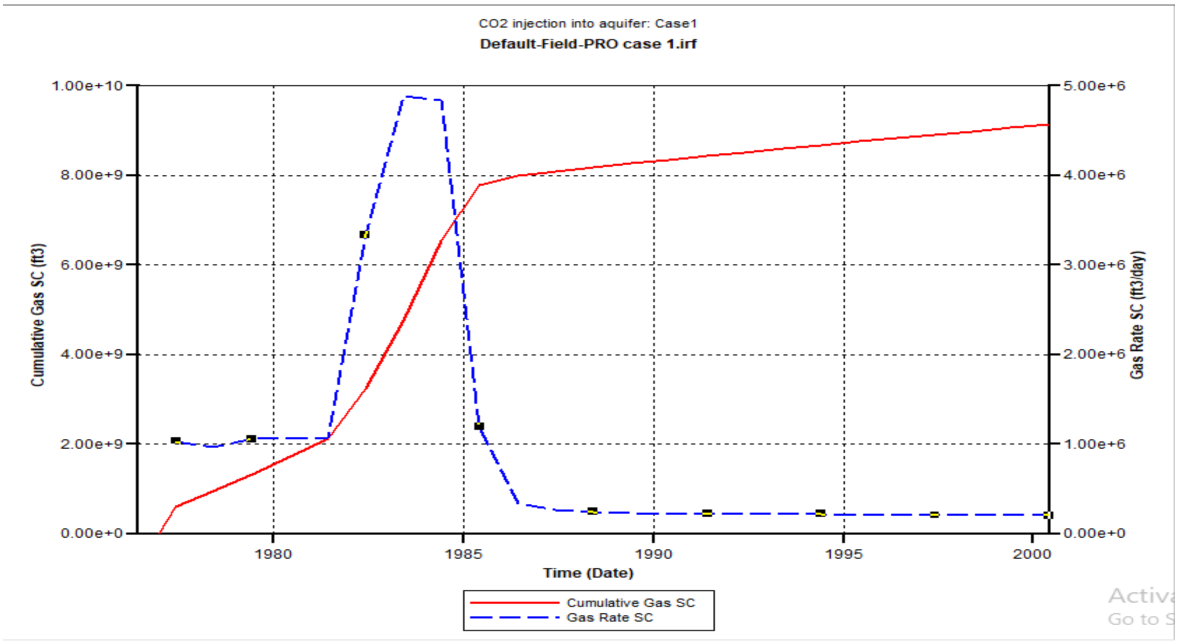

Figure 4.2: Cumulative gas production and gas production rate for the production life of the reservoir model (generated from CMG Results Graph)

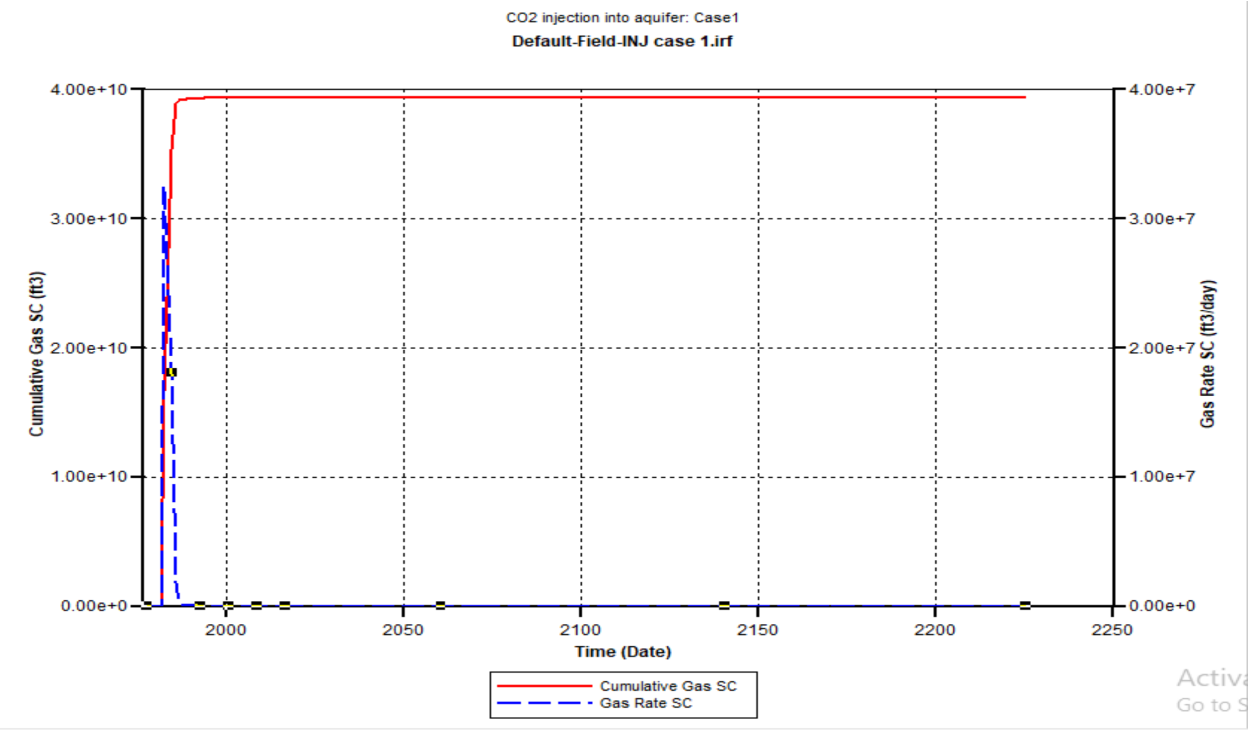

Figure 4.3: Cumulative gas injection and gas injection rate for the production life of the reservoir model (generated from CMG Results Graph)

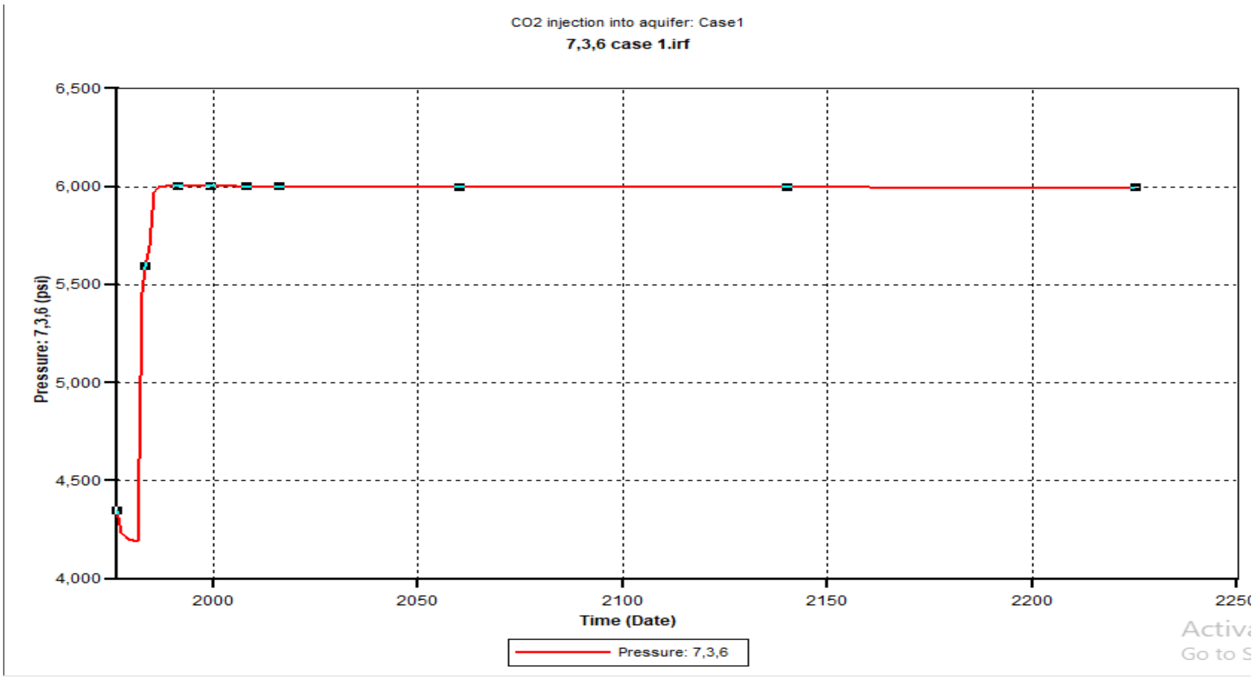

Figure 4.4: Pressure change with time in grid block 7 3 6 (generated from CMG Results Graph)

In terms of amount of CO_2 sequestered, 39.36 Bcf of carbon dioxide was injected in total as shown in Figure 4.3. One restriction to this amount was the pressure of the reservoir. Since the injection wells were constrained to a maximum BHP of 6000psi, this sets the limit for the amount of carbon dioxide to be injected as too much carbon dioxide injected could violate this constraint. Figure 4.4 above shows this pressure rise and limitation with time in grid 7 3 6 – which is the layer containing the aquifer and injection wells.

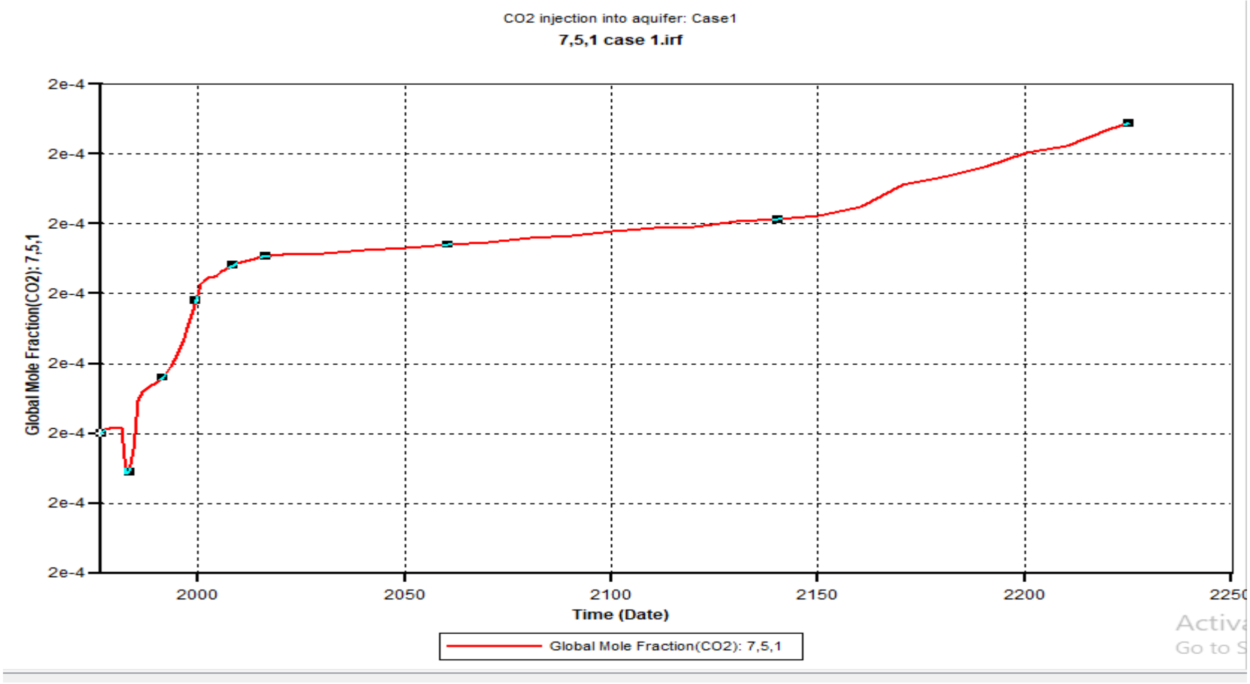

Figure 4.5: Change in mole fraction of CO_2 with time in grid block 7 5 1 (generated from CMG Results Graph)

The base case model demonstrated the possibility of increasing production from a reservoir by carbon dioxide into the aquifer. In addition to the energy of the aquifer pushing the oil, the carbon dioxide also provides pressure increase to the reservoir which contributes to the driving energy of the reservoir. The carbon dioxide also migrates upward in the reservoir which also contributes to driving the oil from the reservoir. This is supported by Figure 4.5 which shows the increasing mole fraction of CO_2 in the top layer of the model.

From the simulation studies done, the nature of the carbon dioxide in the aquifer is mostly CO_2 in supercritical form - which gives the best result for sequestration in aquifers – with some of the CO_2 being dissolved in the aquifer (Figure 4.6). Other forms in which the CO_2 existed are as aqueous ions and in the mineral state. These four states (supercritical carbon dioxide and dissolved carbon dioxide) are the forms in which the CO_2 existed in the aquifer even till the end of the simulation (after 249 years), although their amounts changed very slowly during this time due to the continuous reaction of the CO_2 with the aquifer / trapping mechanisms. Considering the phase behaviour of carbon dioxide and the reservoir conditions, CO_2 did not exist as either gas or liquid during the simulation life.

Sequestering CO_2 in saline aquifer (as expected) provides a way of CSS while simultaneously increasing the reservoir production.

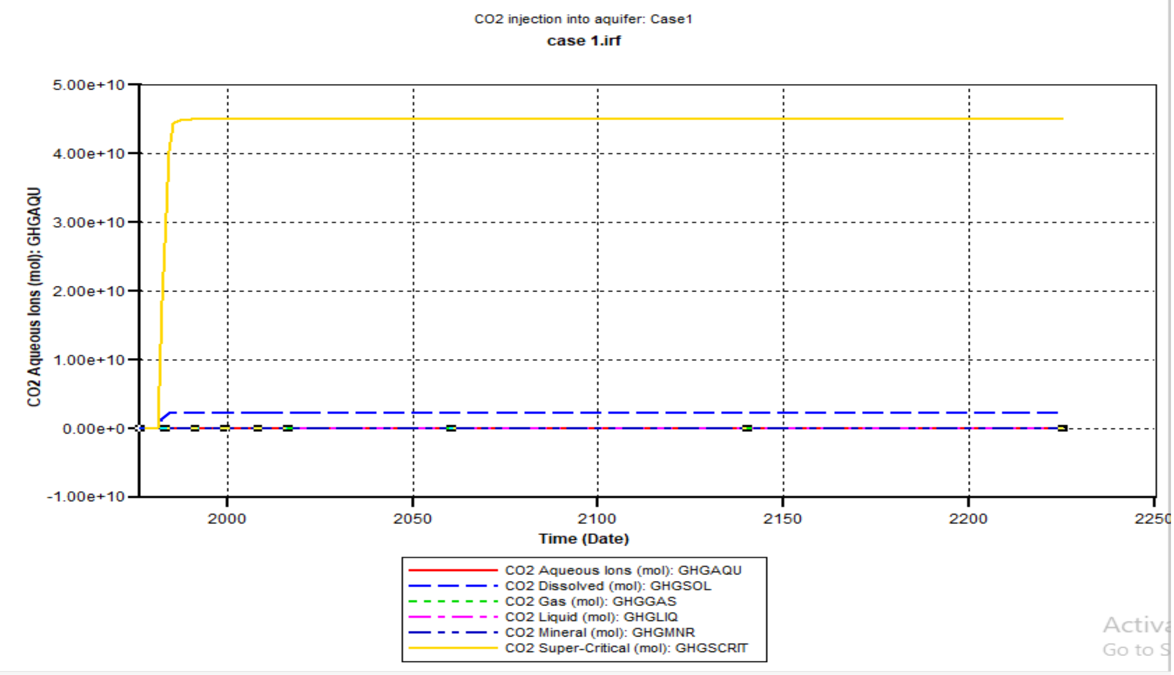

Figure 4.6: Various states in which CO_2 existed throughout the simulation life

4.2. Sensitivity Analysis

Sensitivity analysis helps to find out how different values of an independent variable affect a particular dependent variable under a given set of assumptions (Kenton, 2020). In this section, the independent variables are temperature, pressure and vertical to horizontal permeability ratio. The results of the sensitivity analysis are detailed in this section.

For each of these independent variables, three different values are used (high, low and medium). These three include the base case - Case 1 – whose results were detailed in section 4.1 above as well as two others to see the effect of increasing or decreasing these variables. The results of this sensitivity analysis are shown in Table 4.1.

4.2.1. Temperature effect

One of the determinants of the performance of carbon sequestration projects is the temperature conditions of the reservoir. To check the extent to which temperature affects reservoir performance, the reservoir was subjected to three different temperature regimes. These temperature regimes include: low temperature regime (130F), medium temperature regime (178F) and base case representing the high temperature regime (212F).

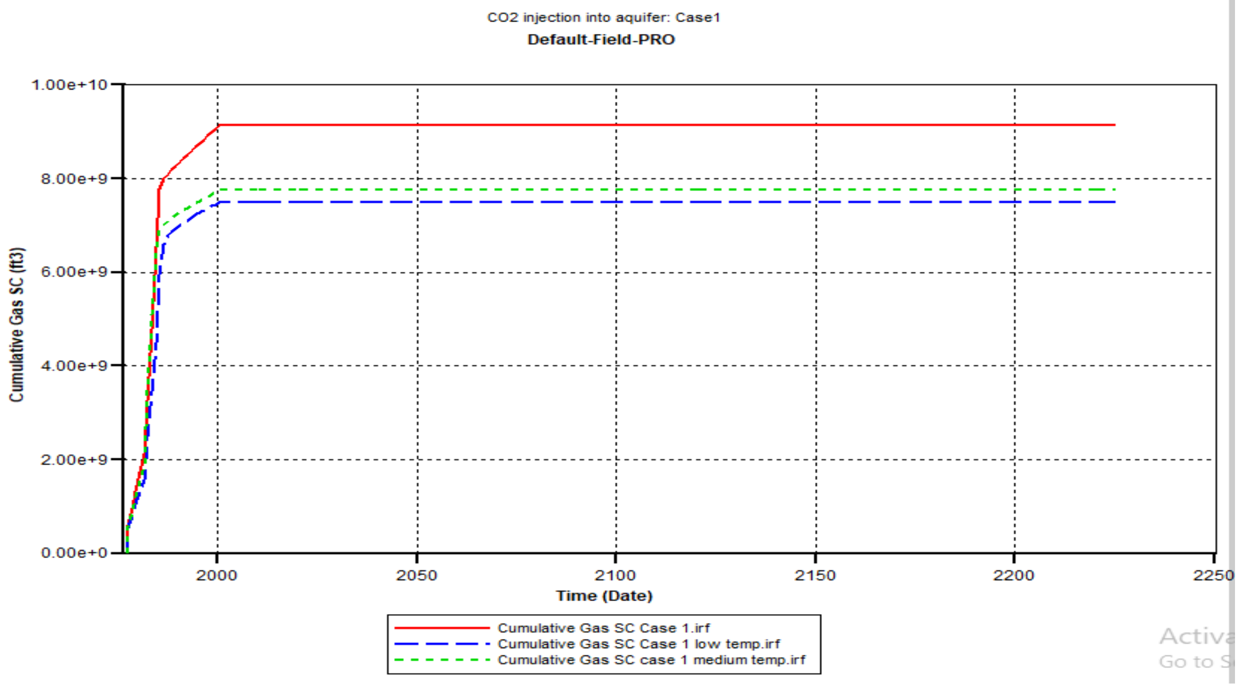

Figure 4.7: Cumulative gas production with time for low, medium and high temperature regime (generated from CMG Results Graph)

Figure 4.7 and 4.8 show the effect of temperature on gas production and oil production respectively. For gas production, 7.5 Bcf, 7.767 Bcf and 9.137 Bcf of gas were produced for the low, medium and high temperature regimes respectively while for oil production 10.716MMbbl, 11.144MMbbl, 13.160MMbbl of oil were produced for the low, medium and high temperature regimes respectively.

It is obvious from these results that increasing temperature leads to more oil and gas production. This increase can be attributed to reduced oil viscosity and lower interfacial tension as a result of temperature increase. Reduced viscosity means easier flow of oil to the production well and more favourable mobility ratio and lower interfacial tension makes it easier for the injected CO_2 to be dissolved in the oil, which helps to move the oil to the production well. This increased oil production with temperature was also seen by Rudyk et al. (2018) in the simulated study of the extraction of crude oil using supercritical CO_2 using a high pressure extractor while an increase in gas production as a result of temperature increase was seen by Pallipurath (2013).

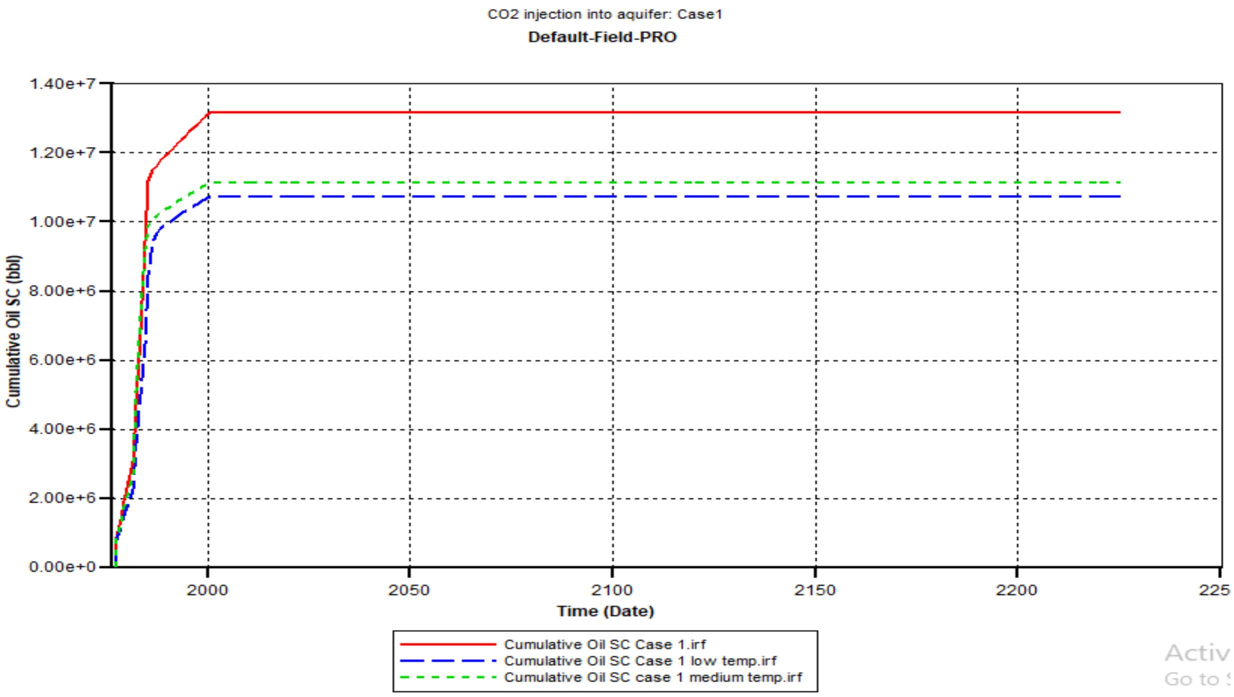

Figure 4.8: Cumulative oil production with time for low, medium and high temperature regime (generated from CMG Results Graph)

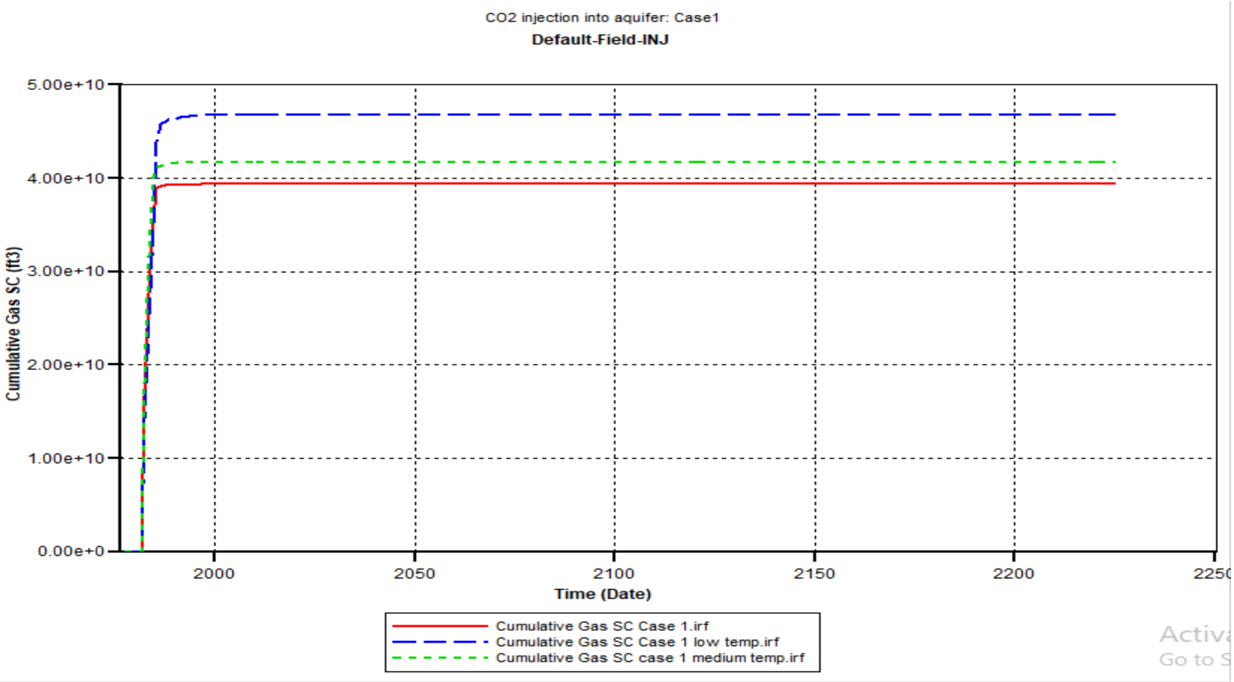

Figure 4.9: Cumulative gas injection with time for low, medium and high temperature regime (generated from CMG Results Graph)

Interestingly, the effect of temperature on injected gas amount showed an opposite effect to production. For injection, temperature and injected gas amount showed an inverse relationship, that is, at higher temperatures lower levels of gas could be injected as shown in Figure 4.9.

For the low, medium and high temperature regimes, 46.788, 41.756 Bcf and 39.358 Bcf of gas were injected respectively. It is not surprising that the amount of CO_2 that can be dissolved in the reservoir when subjected to different temperatures (shown in Figure 4.10) corresponds to the amount of CO_2 that can be sequestered in the aquifer. Although some studies have shown a directly proportional relationship between the dissolution of CO_2 into aquifer and temperature, other studies have shown contradictory results which agree with the results in this thesis. These contradictory results are usually gotten in situations where the conditions for the sequestration process are high pressured areas (Teng & Yamasaki, 1998; Stewart & Munjal, 1970)

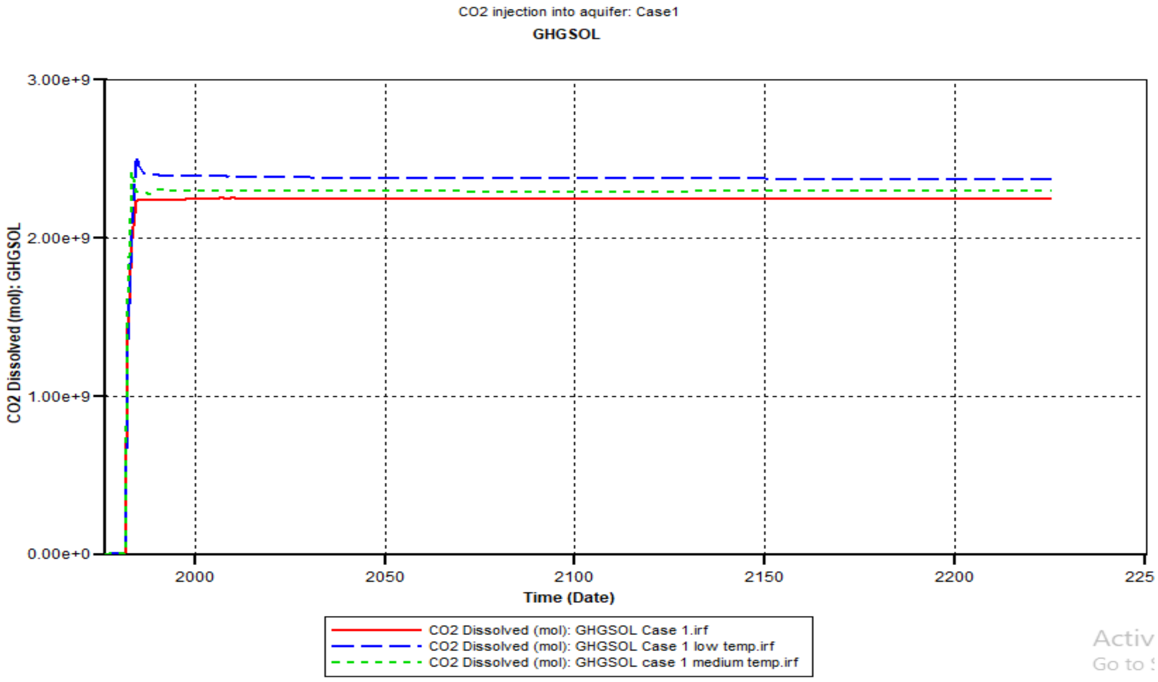

Figure 4.10: Amount of CO_2 dissolved in the aquifer with time for low, medium and high temperature regime (generated from CMG Results Graph)

4.2.2. Pressure effect

Pressure is another variable that could influence the outcome of the carbon dioxide sequestration process in aquifers. This thesis used three different pressure regimes to check this pressure effect on simulation outcome – 4500psi, 5250psi and 6000psi (base case) for the low, medium and high pressure regimes. As can be seen in Figure 4.11 and Figure 4.12, the relationship between pressure and hydrocarbon production is directly proportional. This proportional relationship can be attributed to the pressure being the limit of injection of carbon dioxide. In simpler terms, ensuring the various pressure regimes were done by making the maximum limit of the injection wells equal to the desired pressure. Since injecting the carbon dioxide causes an increase in the pressure of the reservoir, the pressure limitation directly influences the amount of carbon dioxide that can be injected (as shown in Figure 4.13). Therefore, the lower pressure regime means lower carbon dioxide injection and consequently, lower increase in production.

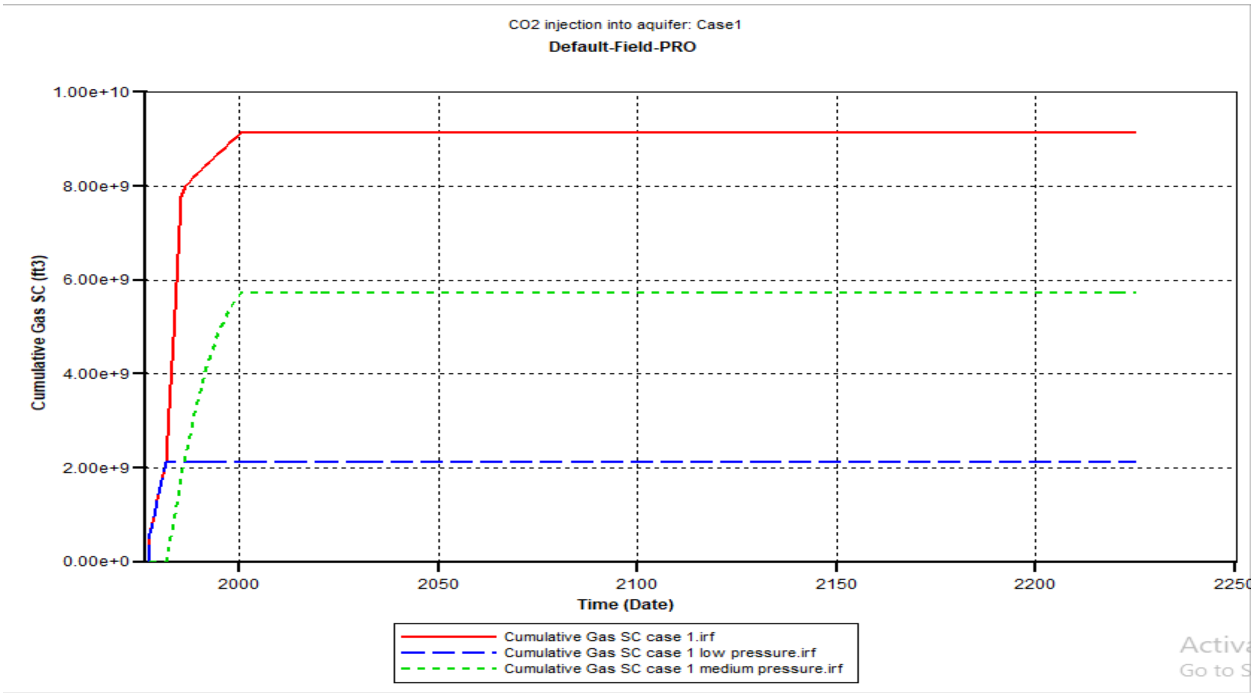

Figure 4.11: Cumulative gas production with time for low, medium and high pressure regime (generated from CMG Results Graph)

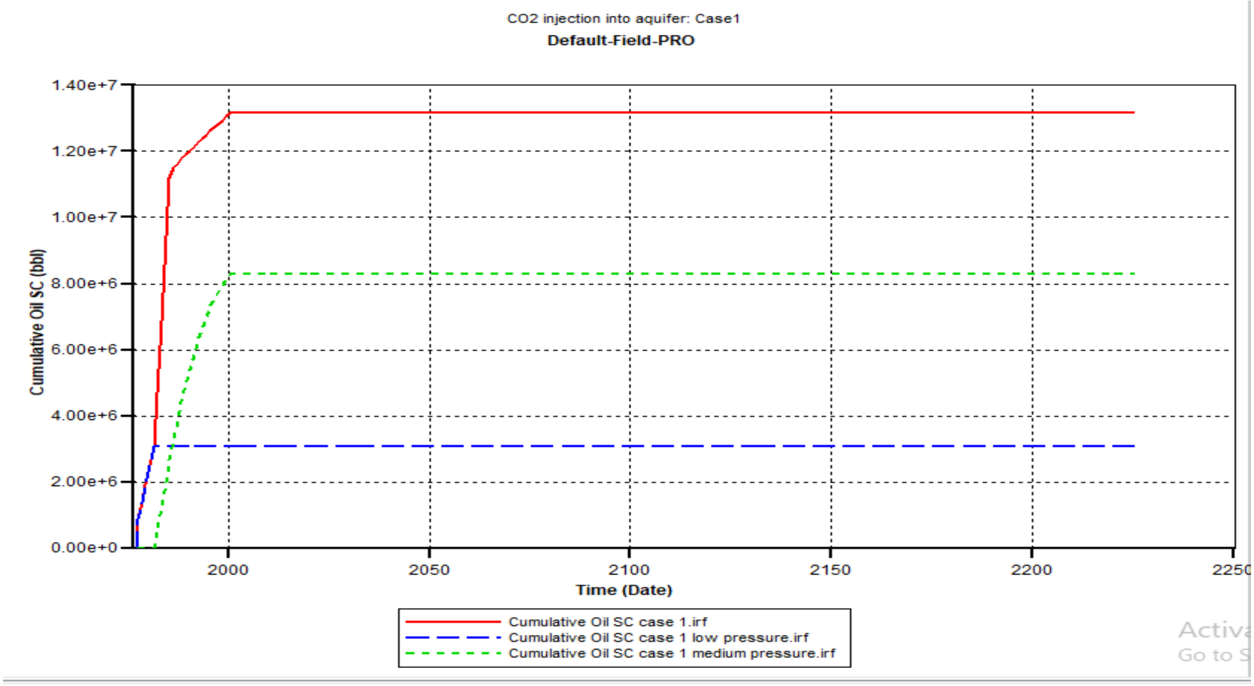

Figure 4.12: Cumulative oil production with time for low, medium and high pressure regime (generated from CMG Results Graph)

The gas production for the low, medium and high-pressure regimes respectively are 2.115 Bcf, 5.733Bcf and 9.137Bcf, oil production for the low, medium and high-pressure regimes are 3.06MMbbl, 8.294MMbbl and 13.160MMbbl respectively and gas injection for the low medium and high-pressure regimes are 1.198Bcf, 30.21Bcf and 39.358Bcf respectively.

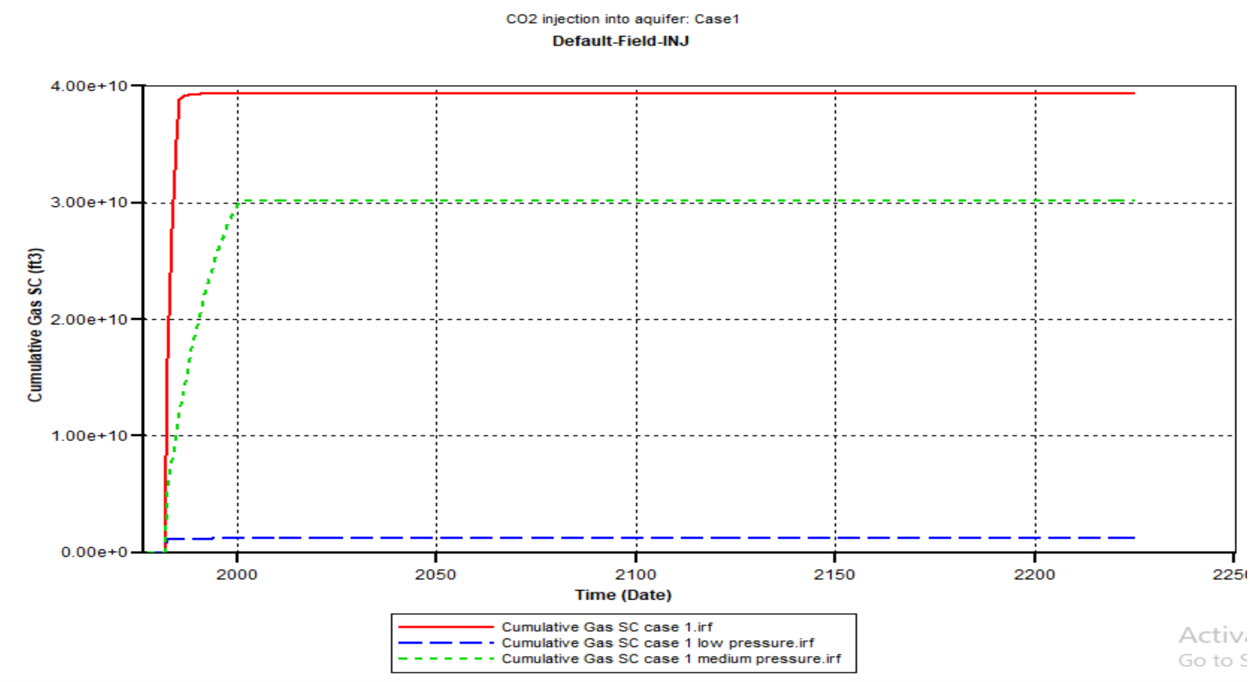

Figure 4.13: Cumulative gas injection with time for low, medium and high pressure regime (generated from CMG Results Graph)

Li et al. (2017) performed a laboratory study to find the effect of pressure on oil recovery and found results that agree with the results gotten from this thesis. The study also pointed out that in cases where the reservoir pressure is below the minimum miscibility pressure, increasing the reservoir pressure above this minimum miscibility pressure causes the CO_2 injection to become miscible, which will lead to better recovery but increased oil recovery was seen whether the reservoir pressure was below or above the minimum miscibility pressure. Similarly, Khan et al. (2013) found results for gas injection that are consistent with the results from the simulation in this thesis. Jen et al. (2017) in a numerical study on geological CO_2 storage in the Northwest Taiwan Basin, also found a directly proportional relationship for pressure and cumulative injected CO_2.

Another thing to be considered is that the pressure also has a proportional relationship to amount of CO_2 dissolution in the aquifer as shown in Figure 4.14 below. Results from previously published studies such as Wiebe & Gaddy (1940) and Dhima et al. (1999) also found this relationship between pressure and CO_2 dissolution in aquifers.

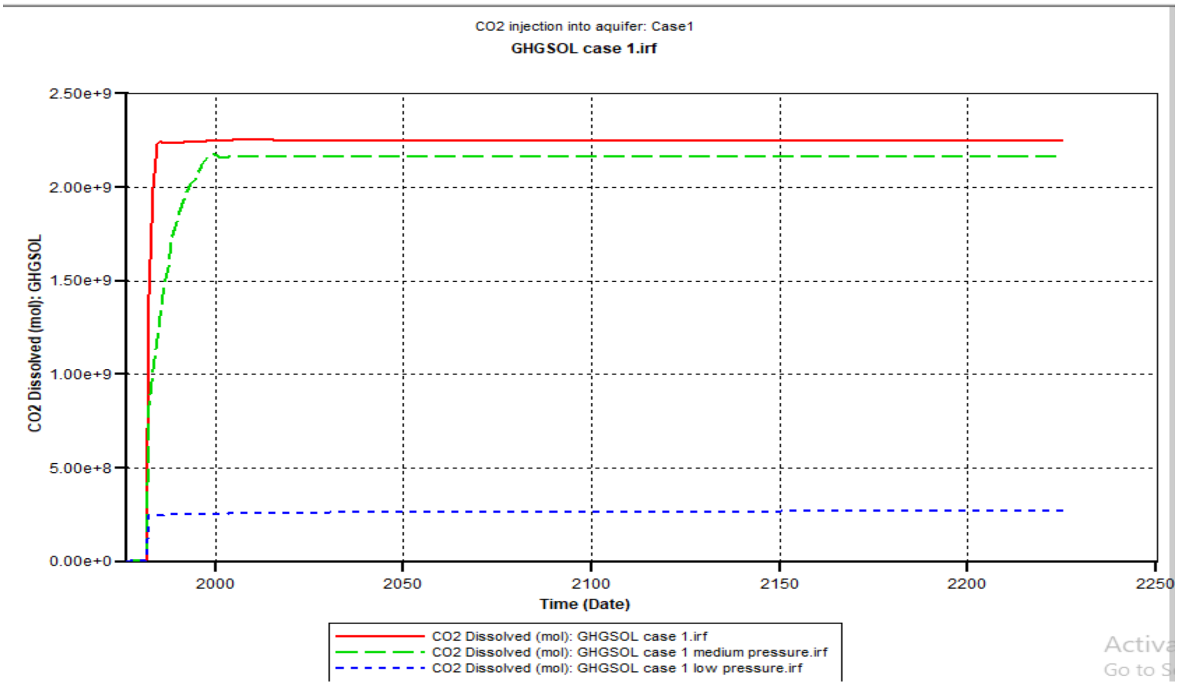

Figure 4.14: Amount of CO_2 dissolved in the aquifer with time for low, medium and high pressure regime (generated from CMG Results Graph)

4.2.3. Vertical to horizontal permeability effect

The ratio of vertical to horizontal permeability has been seen in previous studies to affect the outcome of hydrocarbon production.

To check this effect three different vertical to horizontal relative permeability ratios were used: low (0.01), medium (which is the base case at 0.1) and high (1). For the low case - since the ratio of vertical to horizontal permeability is 0.01 – the vertical permeability is 100 times less than the horizontal permeability, for the medium case, the vertical permeability is 10 times less than the horizontal permeability and for the high case, the vertical and horizontal permeability is equal. To ensure accuracy of comparison of the results for each of these cases, the same horizontal permeabilities were used for all three cases.

Figure 4.15 and 4.16 show the cumulative gas and oil production with time for the low, medium and high ratio of vertical to horizontal permeability. Figure 4.17 below shows the cumulative carbon dioxide injection for low, medium and high ratio of vertical to horizontal permeability. 647.13Bcf, 9.137Bcf and 7.47Bcf of gas were produced for the low, medium and high vertical to horizontal permeability anisotropy respectively while 13.412MMbbl, 13.16MMbbl and 10.666MMbbl of oil were produced for the low, medium and high vertical to horizontal permeability anisotropy respectively. For the gas injection, 686.35Bcf, 39.358Bcf and 37.232Bcf of carbon was sequestrated for the low, medium and high vertical to horizontal permeability anisotropy respectively.

These results showed an inversely proportional relationship between permeability anisotropy and gas production, oil production and gas injection. This inverse relationship between hydrocarbon production and gas injection and vertical to horizontal relative permeability anisotropy has been seen in various previously published literature such as Zakaria (2011).

It is also interesting to note that higher permeability anisotropy values led to lower dissolved gas – as can been seen from Figure 4.18 - which correlates to the cumulative carbon dioxide injection seen in Figure 4.17. It makes sense that the limit of carbon sequestration in this aquifer is the amount of carbon that can be dissolved in the aquifer at different conditions. Studies done by Khudaida & Das (2020) and Abbaszadeh & Shariatipour (2018) showed similar behaviour of gas dissolution with varying vertical to horizontal permeability anisotropy.

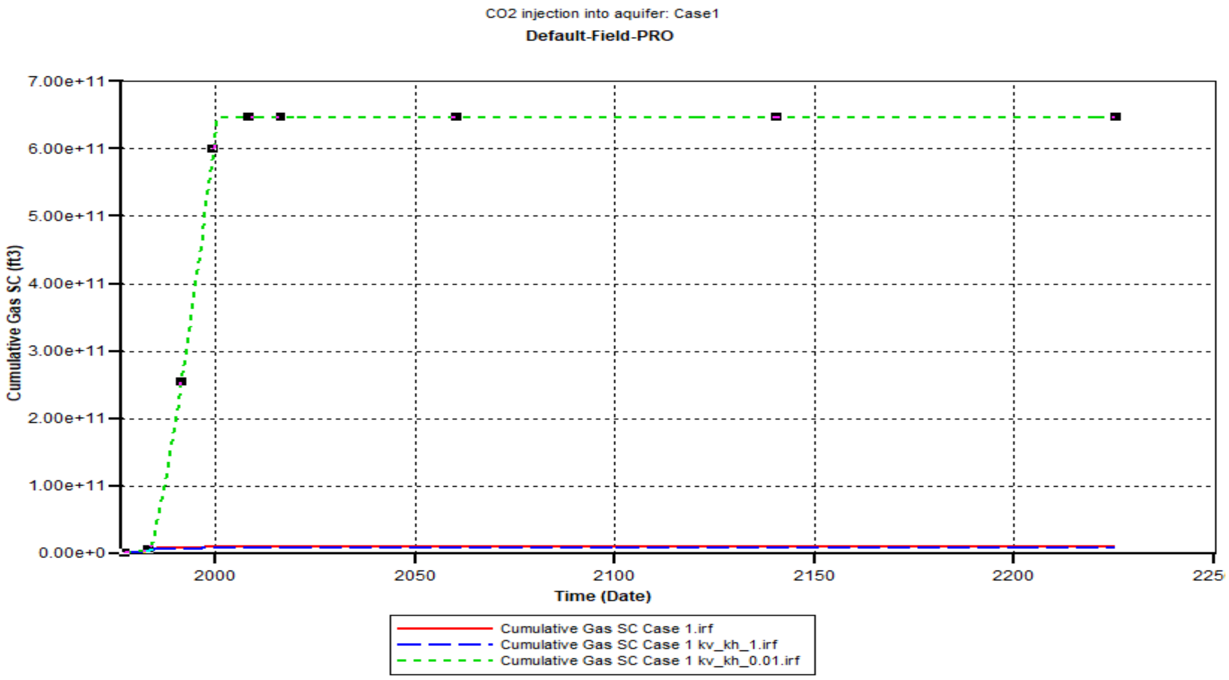

Figure 4.15: Cumulative gas production with time for low, medium and high vertical to horizontal permeability ratio (generated from CMG Results Graph)

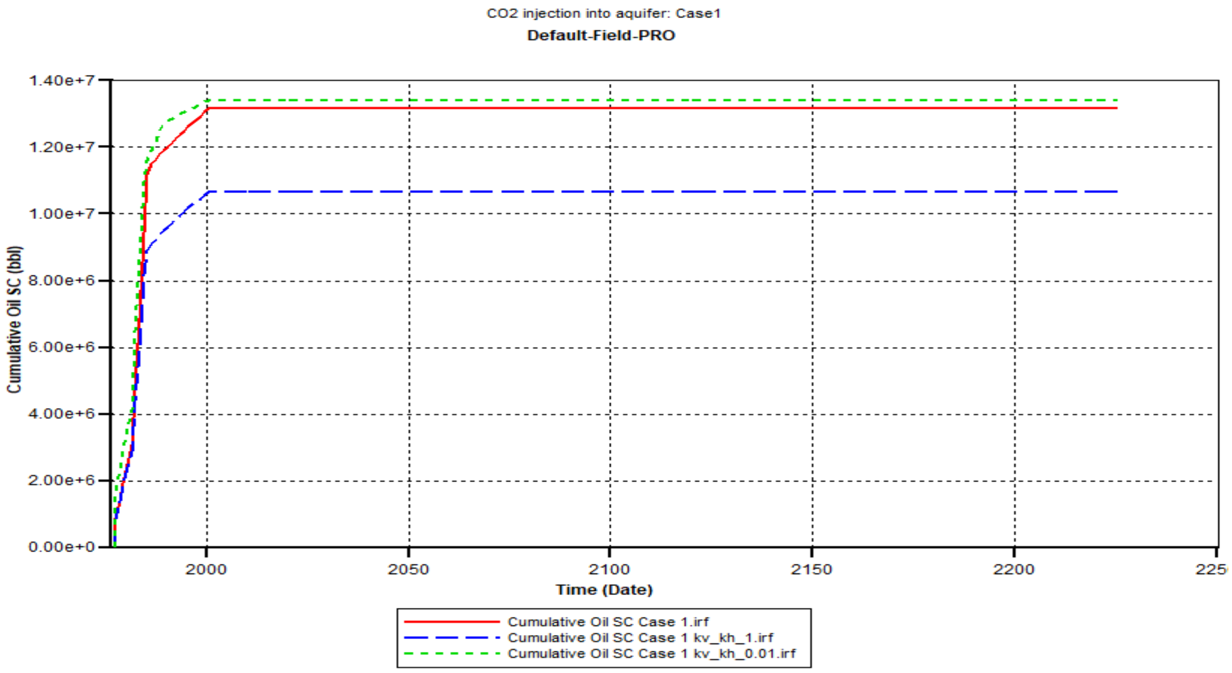

Figure 4.16: Cumulative oil production with time for low, medium and high vertical to horizontal permeability ratio (generated from CMG Results Graph)

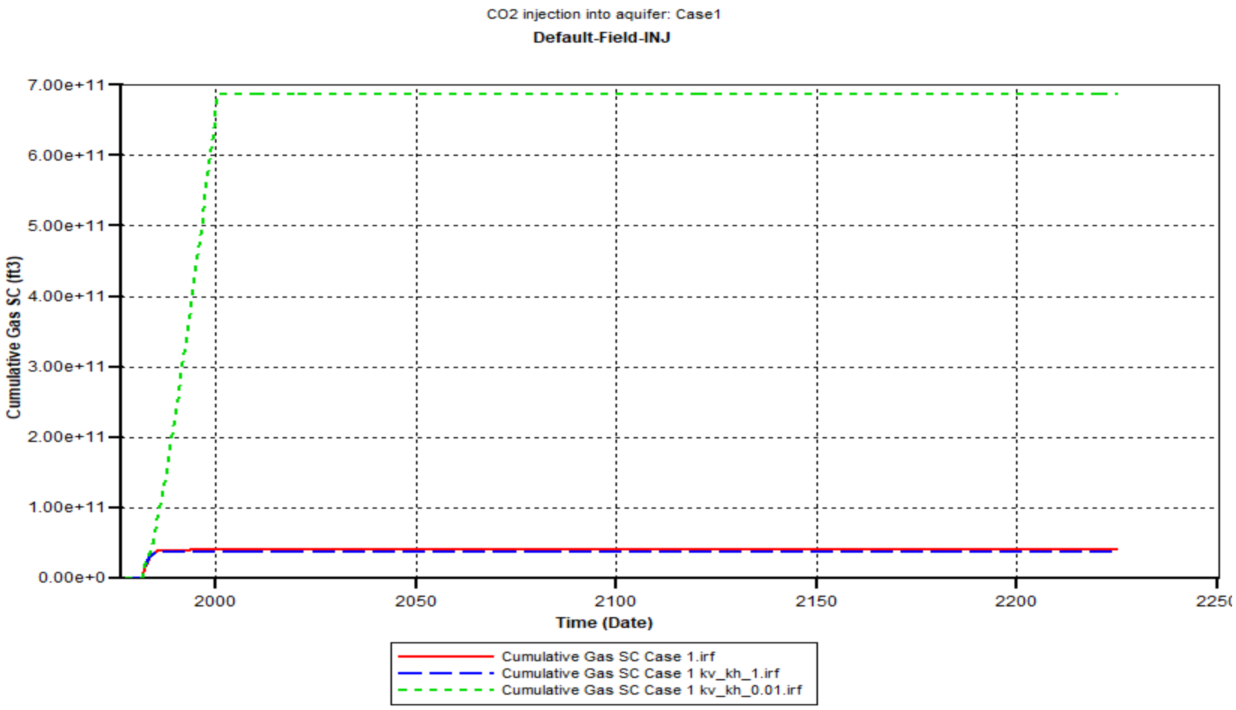

Figure 4.17: Cumulative gas injection with time for low, medium and high vertical to horizontal permeability ratio (generated from CMG Results Graph)

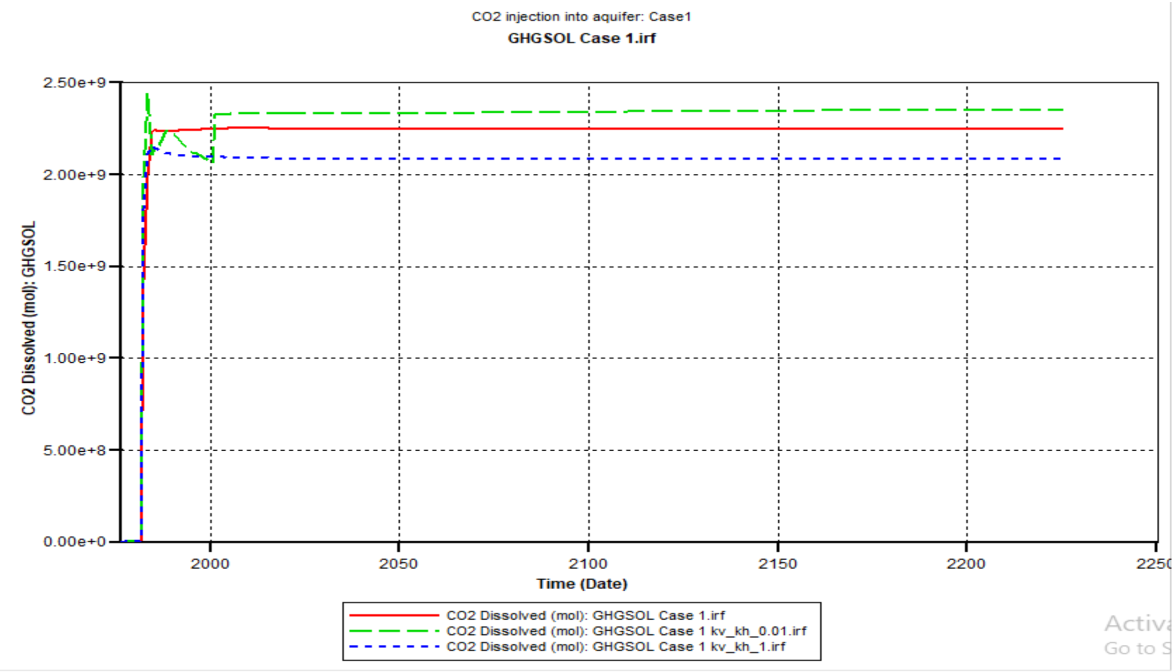

Figure 4.18: Amount of CO_2 dissolved in the aquifer with time for low, medium and high pressure regime (generated from CMG Results Graph)

Table 4.1: Summary of sensitivity analysis

PARAMETER	**EFFECT ON PRODUCTION**	**EFFECT ON INJECTION**
Temperature	Increasing reservoir temperature leads to an increase in oil/gas production	Increasing reservoir temperature leads to a decrease in CO_2 dissolution in aquifer and cumulative CO_2 injection
Pressure	Increasing reservoir pressure leads to an increase in oil/gas production	Increasing reservoir pressure leads to an increase in CO_2 dissolution in aquifer and cumulative CO_2 injection
Vertical horizontal permeability ratio	Increasing the permeability anisotropy of the reservoir leads to a decrease in oil/gas production	Increasing the permeability anisotropy of the reservoir leads to a decrease in CO_2 dissolution in aquifer and cumulative CO_2 injection

CHAPTER 5

CONCLUSIONS AND RECOMMENDATIONS

5.1. Conclusions

In this thesis, the possibility of applying CSS to aquifers is studied using the Ogharefe field in Nigeria as a case study. In Nigeria, where large volumes of GHG are released, this can be a very useful method of reducing the amount of carbon dioxide that is released to the atmosphere.

This study used CMG GEM compositional simulator to model the geochemical and heat loss effects of carbon injection into the aquifer of the Ogharefe field. From the simulation done, it was seen that:

1. the Ogharefe aquifer is a good candidate for sequestration with the potential for 39.36 Bcf of carbon dioxide to be sequestered in it.
2. In addition to this sequestration, incremental hydrocarbon production can be realised from this injection into the aquifer as a result of reservoir repressurization.
3. Sensitivity analysis showed that temperature, pressure and the permeability anisotropy all have considerable effect on the result of the simulation so in order to maximize injection/production, these amounts must be taken into careful consideration.
4. It was also seen from this simulation that most of the sequestered carbon stayed in the aquifer throughout the simulation life (long after injection and production was stopped) even when the temperature, pressure and permeability anisotropy was changed.

5.2. Recommendations

Since the accuracy of simulation results depend on the reservoir accuracy, actual field data could prove helpful in proper reservoir modelling leading to more accurate results.

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APPENDICES

APPENDIX 1

CMG DATA FILE FOR CASE 1

```
** --------------------------------------------------------------------**
** CO2 Sequestration With Geochemistry and Thermal                    **
** --------------------------------------------------------------------**
RESULTS SIMULATOR GEM 201410


** ------- Input/Output ----------------------------------------------
*TITLE1 'CO2 injection into aquifer: Case1'
*TITLE2 'geochemistry and thermal effects'
*INUNIT *FIELD
WSRF WELL TIME
*WSRF *GRID  *TIME
*WSRF *GRIDDEFORM *TIME

*DIARY *CHANGES-UNCONV
*WPRN *WELL  *TIME
*WPRN *GRID  *TIME
*WPRN *ITER  *BRIEF
*OUTPRN *RES *ALL
*OUTPRN *GRID *IMPL *Z 'CO2' *W 'CO2' *SG *SATP
*OUTPRN *GRID *IMPL *TEMP *MOLALITY 'CO2'
**OUTPRN *GRID *MINERAL 'CALCITE' *MINERAL 'Magnesi*'
*OUTPRN *GRID *ACTIV 'Ca++' *ACTIVCOEF 'Ca++' *ACTIVCOEF 'CO2'
*OUTSRF *GRID *SW *SG *PRES *DENW *DENG *TEMP
*OUTSRF *GRID *Z 'CO2' *W 'CO2'
*OUTSRF *GRID *MOLALITY 'CO2' *MOLALITY 'H+' *MOLALITY 'Ca++'
*OUTSRF *GRID *MOLALITY 'Mg++' *MOLALITY 'Na+' *MOLALITY 'OH-'
**OUTSRF *GRID *MOLALITY 'CO3--' *MOLALITY 'HCO3-' *MOLALITY 'CaHCO3-'
*OUTSRF *GRID *MOLALITY 'Cl-' *MOLALITY 'CaCO3' *MOLALITY 'CaOH+'
**OUTSRF *GRID *MINERAL 'Magnesi*' *MINERAL 'CALCITE'
*OUTSRF *GRID *ACTIV 'Ca++' *ACTIVCOEF 'Ca++' *ACTIVCOEF 'CO2'
*OUTSRF *WELL *PSPLIT
*OUTSRF *WELL *GHGSOL *GHGLIQ *GHGSCRIT *GHGAQU *GHGMNR *GHGGAS
*OUTSRF *SPECIAL *ACTIV 'Ca++'       5 5 3
*OUTSRF *SPECIAL *ACTIVCOEF 'Ca++'   5 5 3
**OUTSRF *SPECIAL *LSATINDM 'CALCITE' 5 5 3
*OUTSRF *RES *ALL


**--------------------------------------RESERVOIR & GRID DATA------------
*GRID *CART 15 15 6
*KDIR *DOWN
*DI *CON 622
*DJ *CON 622
*DK *KVAR 15 15 10 10 10 10
*DTOP 225*9800
**  0 = null block, 1 = active block
NULL CON         1
*POR *KVAR 2*0.23 2*0.21 2*0.15
*PERMI *KVAR 850 300 2*450 2*1050
*PERMJ *KVAR 850 300 2*450 2*1050
*PERMK *KVAR 85 30 2*45 2*105
```

```
**  0 = pinched block, 1 = active block
PINCHOUTARRAY CON            1
*CPOR 5.8D-07
*AQUIFER *REGION 1:15 1:15 5:6 *IDIR
*AQPROP
20 0.15 1050 98959.59 0.07
*HEAT-LOSS *BOTTOM-TOP-BOUNDARY
*HLPROP 145 0.2 2
**------------------------------------FLUID PROPERTY DATA--------------

** Model and number of components
MODEL PR
NC 7 7
COMPNAME 'CO2' 'N2 toCH4' 'C2HtoIC4' 'NC4toC11' 'C12toC19' 'C20toC29'
'C30+'
TRES 212
VISCOR HZYT
MIXVC 0.9043
PVC3 1.2000000E+00
VISCOEFF
1.4512000E-01 3.6910000E-08 1.6825902E-07 -6.6483000E-03 1.0765000E-02
MW
4.4010000E+01 1.6245401E+01 3.8249472E+01 1.0869683E+02 2.0651487E+02
3.2097460E+02 4.4991048E+02
AC
0.225 0.00690313 0.125075 0.48118 0.49493 0.948738 0.948776
PCRIT
7.2800000E+01 4.5730346E+01 4.4418396E+01 3.1944916E+01 2.4029000E+01
9.6400107E+00 1.3095572E+01
VCRIT
9.4000000E-02 9.8836710E-02 1.7933069E-01 4.2641554E-01 7.7756916E-01
1.1658595E+00 1.2504773E+00
TCRIT
3.0420000E+02 1.9540714E+02 3.2237358E+02 5.8780054E+02 6.5949416E+02
8.9667839E+02 1.1656805E+03
PCHOR
78 76.3913 131.45 314.673 559.385 796.226 996.6
SG
0.818 0.305606 0.437452 0.744146 0.835528 0.883504 1.1
TB
-78.45 -159.049 -40.0601 128.083 268.009 383.366 586.288
HCFLAG
0 0 0 0 0 0 0
OMEGA
0.457236 0.457236 0.457236 0.457236 0.457236 0.457236 0.457236
OMEGB
0.0777961 0.0777961 0.0777961 0.0777961 0.0777961 0.0777961 0.0777961
VSHIFT
-0.0817 -0.15343 -0.106605 0.0562093 0.141623 0.122856 0.176897
VISVC
9.4000000E-02 9.8840666E-02 1.8128199E-01 5.2147000E-01 3.6192000E-01
1.1513369E+00 1.1938706E+00
YAQU-RATE-CUTOFF
1.0e-8 1.0 1.0 1.0 1.0 1.0 1.0
BIN
1.3799217E-04
5.0000000E-02 5.4014822E-03
3.2384811E-01 3.1831713E-02 1.1362967E-02
```

```
8.5345704E-02 6.1798139E-02 3.2044019E-02 5.4920503E-03
0.0000000E+00 8.6587883E-02 5.1349755E-02 1.5272712E-02 2.5025318E-03
4.8228981E-02 9.1207091E-02 5.5091770E-02 1.7443830E-02 3.4406286E-03
7.5032986E-05

CW 3E-06
REFPW 4335
SOLUBILITY HENRY
EQUIL-REACT-RATE ON
CHEM-EQUIL-SET ON
DERIVATIVEMETHOD NUMERALL
DER-CHEM-EQUIL NUMERICAL
DER-REACT-RATE NUMERICAL
ACTIVITY-MODEL B-DOT
SALINITY-CALC ON
HENRY-CORR-CO2
RF_EXPONENT 3.0
RFCALC POWER
NC-AQUEOUS 10
COMPNAME-AQUEOUS
 'H+' 'Ca++' 'HCO3-' 'Mg++' 'Na+' 'Cl-' 'OH-' 'CaOH+' 'CaHCO3+' 'CaCO3'
MW-AQUEOUS
 1.0079 40.08 61.0171 24.305 22.9898 35.453 17.0073 57.0873 101.097
100.089
ION-SIZE-AQUEOUS
 9 6 4.5 8 4 3 3.5 4 5.2 4
CHARGE-AQUEOUS
 1 2 -1 2 1 -1 -1 1 1 0
NC-MINERAL 2
COMPNAME-MINERAL
 'Calcite' 'Magnesi*'
MW-MINERAL
 100.089 84.3142
MASSDENSITY-MINERAL
 2709.95 3009.29
N-CHEM-EQUIL 4
N-RATE-REACT 2
**REACTION NO.   355: +  (H+)  (OH-) =  H2O
STOICHIOMETRY
 0 0 0 0 0 0 0 1 -1 0 0 0 0 0 -1 0 0 0 0 0
LOG-CHEM-EQUIL-COEFS
 14.9282 -0.0418762 0.000197367 -5.54951e-007 7.58109e-010
**REACTION NO.   96: +  (CaOH+)  (H+) =  (Ca++) +  H2O
STOICHIOMETRY
 0 0 0 0 0 0 0 1 -1 1 0 0 0 0 0 -1 0 0 0 0
LOG-CHEM-EQUIL-COEFS
 13.7081 -0.04389 0.000134077 -2.35793e-007 9.75054e-011
**REACTION NO.   93:  (CaHCO3+) =  (Ca++) +  (HCO3-)
STOICHIOMETRY
 0 0 0 0 0 0 0 0 0 1 1 0 0 0 0 0 -1 0 0 0
LOG-CHEM-EQUIL-COEFS
 -1.18729 0.00164938 -0.000118857 8.57886e-007 -2.04302e-009
**REACTION NO.   88: +  CaCO3  (H+) =  (Ca++) +  (HCO3-)
STOICHIOMETRY
 0 0 0 0 0 0 0 0 -1 1 1 0 0 0 0 0 0 -1 0 0
LOG-CHEM-EQUIL-COEFS
 7.54394 -0.0180077 8.32956e-005 -1.3837e-007 -1.37018e-010
**REACTION NO.   113: Calcite(CaCO3)+  (H+) =  (Ca++) +  (HCO3-)
```

```
STOICHIOMETRY
 0 0 0 0 0 0 0 0 -1 1 1 0 0 0 0 0 0 0 -1 0
LOG-CHEM-EQUIL-COEFS
 2.06889 -0.0142668 -6.06096e-006 1.45921e-007 -4.18928e-010
REACTIVE-SURFACE-AREA 100
ACTIVATION-ENERGY 41870
LOG-TST-RATE-CONSTANT -8.8
REF-TEMP-RATE-CONST 25
**REACTION NO.   307: Magnesite(MgCO3)+  (H+) =  (HCO3-) +  (Mg++)
STOICHIOMETRY
 0 0 0 0 0 0 0 0 -1 0 1 1 0 0 0 0 0 0 0 -1
LOG-CHEM-EQUIL-COEFS
 3.11813 -0.0283728 4.14154e-005 4.75659e-008 -3.48756e-010
REACTIVE-SURFACE-AREA 100
ACTIVATION-ENERGY 41870
LOG-TST-RATE-CONSTANT -8.8
REF-TEMP-RATE-CONST 25
ANNIH-MATRIX
1 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0
0 1 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0
0 0 1 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0
0 0 0 1 0 0 0 0 0 0 0 0 0 0 0 0 0 0
0 0 0 0 1 0 0 0 0 0 0 0 0 0 0 0 0 0
0 0 0 0 0 1 0 0 0 0 0 0 0 0 0 0 0 0
0 0 0 0 0 0 1 0 0 0 0 0 0 0 0 0 0 0
0 0 0 0 0 0 0 1 0 0 0 0 0 0 1 1 0 0
0 0 0 0 0 0 0 0 1 0 0 0 0 0 -1 -1 0 -1
0 0 0 0 0 0 0 0 0 1 0 0 0 0 0 1 1 1
0 0 0 0 0 0 0 0 0 0 1 0 0 0 0 0 1 1
0 0 0 0 0 0 0 0 0 0 0 1 0 0 0 0 0 0
0 0 0 0 0 0 0 0 0 0 0 0 1 0 0 0 0 0
0 0 0 0 0 0 0 0 0 0 0 0 0 1 0 0 0 0
NC-IEX 3
COMPNAME-IEX
 'H-X' 'Na-X' 'Ca-X2'
AQIONS-IEX
 'H+' 'Na+' 'Ca++'
**Stoichiometry for ion-exchanger 1
STOICH-IEX
'H+' -1
'H-X' 1
'Na+' 1
'Na-X' -1
**Selectivity cofficents for ion-exchanger 1
SCOEFF-IEX
25 0.01
90 0.4
**Stoichiometry for ion-exchanger 2
STOICH-IEX
'Ca++' 0.5
'Ca-X2' -0.5
'Na+' -1
'Na-X' 1
**Selectivity cofficents for ion-exchanger 2
SCOEFF-IEX
25 0.01
90 0.4
EQUIL-REACT-RATE ON
```

```
CHEM-EQUIL-SET ON
EQUIL-REACT-RATE ON
CHEM-EQUIL-SET ON
EQUIL-REACT-RATE ON
CHEM-EQUIL-SET ON

EQUIL-REACT-RATE ON
CHEM-EQUIL-SET ON
EQUIL-REACT-RATE ON
CHEM-EQUIL-SET ON
*SALINITY 0.1
*AQUEOUS-DENSITY *ROWE-CHOU
*AQUEOUS-VISCOSITY *KESTIN
*OGW_FLASH *NO_H2OVAP

** -------------------- ROCK-FLUID DATA------------------------
*ROCKFLUID
**insert first rpt table for reservoir zone
*RPT 1  *IMBIBITION
*SWT

   0.3000 0.0000 0.8000   20.39
   0.3100 0.0000 0.7545   18.97
   0.4000 0.0000 0.5726   13.30
   0.5000 0.0007 0.3469   8.770
   0.6000 0.0117 0.0652   5.650
   0.7000 0.2000 0.0000   3.680
   0.8000 0.5333 0.0000   2.400
   0.9000 0.7667 0.0000   1.560
   1.0000 1.0000 0.0000   0.000

*SGT

    0.0000 0.0000 0.8000  0.0000
    0.1000 0.0053 0.3191  0.0000
    0.2000 0.0420 0.1778  0.0000
    0.3000 0.1450 0.0652  0.0000
    0.4000 0.4800 0.0000  0.0000
    0.5500 0.6000 0.0000  0.0000
    0.7000 0.6500 0.0000  0.0000

**insert second rpt table for aquifer zone
*RPT 2  *DRAINAGE
INTCOMP EQVFRIEX 'Ca-X2'
KRINTRP 1
INTCOMP_VAL 0.19
*SWT
0.000000  0.000000  0.000000  0.000000
0.050000  0.000000  0.000000  0.000000
0.100000  0.000000  0.000000  0.000000
0.150000  0.000010  0.000000  0.000000
0.200000  0.000150  0.000000  0.000000
0.250000  0.000770  0.000000  0.000000
0.300000  0.002440  0.000000  0.000000
0.350000  0.005950  0.000000  0.000000
0.400000  0.012350  0.000000  0.000000
0.450000  0.022870  0.000000  0.000000
0.500000  0.039020  0.000000  0.000000
```

```
0.550000  0.062500  0.000000  0.000000
0.600000  0.095260  0.000000  0.000000
0.650000  0.139470  0.000000  0.000000
0.700000  0.197530  0.000000  0.000000
0.750000  0.272070  0.000000  0.000000
0.800000  0.365950  0.000000  0.000000
0.850000  0.482250  0.000000  0.000000
0.900000  0.624300  0.000000  0.000000
0.950000  0.795620  0.000000  0.000000
1.000000  1.000000  0.000000  0.000000

*SGT
0.000000  0.000000  0.000000  0.000000
0.050000  0.000080  0.000000  0.000000
0.100000  0.000680  0.000000  0.000000
0.150000  0.002330  0.000000  0.000000
0.200000  0.005610  0.000000  0.000000
0.250000  0.011140  0.000000  0.000000
0.300000  0.019610  0.000000  0.000000
0.350000  0.031740  0.000000  0.000000
0.400000  0.048370  0.000000  0.000000
0.450000  0.070420  0.000000  0.000000
0.500000  0.098940  0.000000  0.000000
0.550000  0.136180  0.000000  0.000000
0.600000  0.180650  0.000000  0.000000
0.650000  0.232750  0.000000  0.000000
0.700000  0.307520  0.000000  0.000000
0.750000  0.395200  0.000000  0.000000
0.800000  0.506570  0.000000  0.000000
0.850000  0.655620  0.000000  0.000000
0.900000  0.954430  0.000000  0.000000
0.950000  0.977220  0.000000  0.000000
1.000000  1.000000  0.000000  0.000000
KRINTRP 2
INTCOMP_VAL 0.4
**         Sw         krw      krow      Pcow
SWT
             0           0         0         0
     0.0222222           0         0         0
     0.0444444           0         0         0
          0.06           0         0         0
          0.08           0         0         0
           0.1           0         0         0
         0.115      9e-008         0         0
          0.13   1.22e-006         0         0
         0.145   5.84e-006         0         0
          0.16  1.772e-005         0         0
         0.175  4.195e-005         0         0
          0.19   8.51e-005         0         0
         0.205  0.00015506         0         0
          0.22    0.000261         0         0
         0.235  0.00041368         0         0
          0.25    0.000625         0         0
         0.265  0.00091984         0         0
          0.28  0.00130628         0         0
         0.295  0.00180112         0         0
          0.31  0.00242254         0         0
         0.325   0.0031901         0         0
```

```
          0.34   0.0041247         0         0
         0.355  0.00524865         0         0
          0.37  0.00658564         0         0
         0.385  0.00816058         0         0
           0.4        0.01         0         0
          0.45      0.0925         0         0
           0.5       0.175         0         0
      0.555556    0.266667         0         0
      0.611111    0.358333         0         0
          0.65      0.4225         0         0
      0.666667    0.450001         0         0
           0.7       0.505         0         0
      0.722222    0.541666         0         0
          0.75      0.5875         0         0
      0.777778    0.633334         0         0
           0.8        0.67         0         0
      0.833333    0.724999         0         0
          0.85      0.7525         0         0
           0.9       0.835         0         0
          0.95      0.9175         0         0
             1           1         0         0
**        Sg       krg      krog      Pcog
SGT
            0         0         0         0  ** -99999
         0.05    8e-005         0         0  ** -99999
          0.1   0.00068         0         0  ** -99999
         0.15   0.00233         0         0  ** -99999
          0.2   0.00561         0         0  ** -99999
         0.25   0.01114         0         0  ** -99999
          0.3   0.01961         0         0  ** -99999
         0.35   0.03174         0         0  ** -99999
          0.4   0.04837         0         0  ** -99999
         0.45   0.07042         0         0  ** -99999
          0.5   0.09894         0         0  ** -99999
         0.55   0.13618         0         0  ** -99999
          0.6   0.18065         0         0  ** -99999
         0.65   0.23275         0         0  ** -99999
          0.7   0.30752         0         0  ** -99999
         0.75    0.3952         0         0  ** -99999
          0.8   0.50657         0         0  ** -99999
         0.85   0.65562         0         0  ** -99999
          0.9   0.95443         0         0  ** -99999
         0.95   0.97722         0         0  ** -99999
            1         1         0         0  ** -99999

*RTYPE *KVAR 1 1 1 1 2 2
CEC-IEX CON           50

** --------------------  INITIAL CONDITIONS -----------------------------
-----------
*INITIAL
*VERTICAL *DEPTH_AVE *WATER_OIL
*NREGIONS 2
*ZOIL
0.0002 0.2957 0.3082 0.0794  0.1734 0.0822 0.0609
0.0002 0.2957 0.3082 0.0794  0.1734 0.0822 0.0609

REFPRES
```

```
  4325  4335

REFDEPTH
  9800  9825

DWOC
  9850  9850

**MOLALITY-AQUEOUS-UNITS *MOL/KG_H2O
*MOLALITY-AQUEOUS
1.000000D-07  9.118492D-05 4.03D-04 1.3202D-03 7.147D-04 2.489299D-02
1.170273D-05 2.345433D-08 2.345433D-08 7.493D-04
1.000000D-07  9.118492D-05 4.03D-04 1.3202D-03 7.147D-04 2.489299D-02
1.170273D-05 2.345433D-08 2.345433D-08 7.493D-04

VOLUMEFRACTION-MINERAL
0.02 0.01
0.02 0.01

** ----------------- Numerical ----------------------
*NUMERICAL
   *NORM *PRESS 6395
   *NORM *SATUR  0.10
   *NORM *GMOLAR 0.10
   **CONVERGE *MAXRES  1.e-4
*NORTH 80
*ITERMAX 100
*PRECC 1.E-05
*DTMIN 1.E-06
*DTMAX 182.5

** -------------------------WELL AND RECURRENT DATA ---------------------
----------------
*RUN
**oil production from single producer
*DATE 1976 06 01

*WELL 'PROD'
PRODUCER 'PROD'
OPERATE  MAX  STO  7000.0  CONT
OPERATE  MIN  BHP  3820.0  CONT
**          rad  geofac  wfrac  skin
GEOMETRY  K  0.2  0.37  1.0  0.0
      PERF       GEO  'PROD'
** UBA             ff          Status  Connection
    7 8 1         1.0  OPEN    FLOW-TO  'SURFACE'  REFLAYER
    7 8 2         1.0  OPEN    FLOW-TO  1
    7 8 3         1.0  OPEN    FLOW-TO  2
    7 8 4         1.0  OPEN    FLOW-TO  3

*DATE 1977 06 01
*DATE 1978 06 01
*DATE 1979 06 01
*DATE 1980 06 01
*DATE 1981 06 01

**oil production from single producer with simultaneous carbondioxide
into aquifer
```

```
*WELL 'INJ1'
INJECTOR 'INJ1'
INCOMP  SOLVENT  1.0  0.0  0.0  0.0  0.0  0.0  0.0
OPERATE  MAX  STG  49400000.0  CONT
OPERATE  MAX  BHP  6000  CONT
**          rad  geofac  wfrac  skin
GEOMETRY  K  0.2  0.37  1.0  0.0
      PERF       GEO  'INJ1'
** UBA             ff          Status  Connection
    1 1 5         1.0  OPEN    FLOW-FROM  'SURFACE'  REFLAYER
    1 1 6         1.0  OPEN    FLOW-FROM  1

*WELL 'INJ2'
INJECTOR 'INJ2'
INCOMP  SOLVENT  1.0  0.0  0.0  0.0  0.0  0.0  0.0
OPERATE  MAX  STG  49400000.0  CONT
OPERATE  MAX  BHP  6000   CONT
**          rad  geofac  wfrac  skin
GEOMETRY  K  0.2  0.37  1.0  0.0
      PERF       GEO  'INJ2'
** UBA              ff           Status  Connection
    15 1 5         1.0  OPEN    FLOW-FROM  'SURFACE'  REFLAYER
    15 1 6         1.0  OPEN    FLOW-FROM  1

*WELL 'INJ3'
INJECTOR 'INJ3'
INCOMP  SOLVENT  1.0  0.0  0.0  0.0  0.0  0.0  0.0
OPERATE  MAX  STG  49400000.0  CONT
OPERATE  MAX  BHP  6000   CONT
**          rad  geofac  wfrac  skin
GEOMETRY  K  0.2  0.37  1.0  0.0
      PERF       GEO  'INJ3'
** UBA              ff           Status  Connection
    1 15 5         1.0  OPEN    FLOW-FROM  'SURFACE'  REFLAYER
    1 15 6         1.0  OPEN    FLOW-FROM  1

*WELL 'INJ4'
INJECTOR 'INJ4'
INCOMP  SOLVENT  1.0  0.0  0.0  0.0  0.0  0.0  0.0
OPERATE  MAX  STG  49400000.0  CONT
OPERATE  MAX  BHP  6000   CONT
**          rad  geofac  wfrac  skin
GEOMETRY  K  0.2  0.37  1.0  0.0
      PERF       GEO  'INJ4'
** UBA               ff           Status  Connection
    15 15 5         1.0  OPEN    FLOW-FROM  'SURFACE'  REFLAYER
    15 15 6         1.0  OPEN    FLOW-FROM  1

*DATE 1982 06 01
*DATE 1983 06 01
*DATE 1984 06 01
*DATE 1985 06 01
*DATE 1986 06 01
*DATE 1987 06 01
*DATE 1988 06 01
*DATE 1989 06 01
*DATE 1990 06 01
*DATE 1991 06 01
```

```
*DATE 1992 06 01
*DATE 1993 06 01
*DATE 1994 06 01
*DATE 1995 06 01
*DATE 1996 06 01
*DATE 1997 06 01
*DATE 1998 06 01
*DATE 1999 06 01
*DATE 2000 06 01

**SHUT IN WELLS
SHUTIN 'INJ1'
SHUTIN 'INJ2'
SHUTIN 'INJ3'
SHUTIN 'INJ4'
SHUTIN 'PROD'

*DATE 2001 06 01
*DATE 2002 06 01
*DATE 2003 06 01
*DATE 2004 06 01
*DATE 2005 06 01

*DATE 2006 06 01
*DATE 2007 06 01
*DATE 2008 06 01
*DATE 2009 06 01
*DATE 2010 06 01

*DATE 2011 06 01
*DATE 2012 06 01
*DATE 2013 06 01
*DATE 2014 06 01
*DATE 2015 06 01

*DATE 2016 06 01
*DATE 2017 06 01
*DATE 2018 06 01
*DATE 2019 06 01
*DATE 2020 06 01

*DATE 2030 06 01
DATE 2040 06 01

DATE 2050 06 01
DATE 2060 06 01
DATE 2070 06 01
DATE 2080 06 01
DATE 2090 06 01
DATE 2100 06 01

DATE 2110 06 01
DATE 2120 06 01
DATE 2130 06 01
DATE 2140 06 01
DATE 2150 06 01

DATE 2160 06 01
```

```
DATE 2170 06 01
DATE 2180 06 01
DATE 2190 06 01
DATE 2200 06 01

DATE 2210 06 01
DATE 2220 06 01
DATE 2225 06 01
*STOP
RESULTS PROCESSWIZ PROCESS 3
RESULTS PROCESSWIZ FOAMYOILMODEL -1
RESULTS PROCESSWIZ SGC 0.15
RESULTS PROCESSWIZ KRGCW 0.0001
RESULTS PROCESSWIZ COALESCENCE -14503.6 FALSE
RESULTS PROCESSWIZ BUBBLEPT -14503.6
RESULTS PROCESSWIZ MINPRESSURE -14503.6 FALSE
RESULTS PROCESSWIZ NUMSETSFOAMY 2
RESULTS PROCESSWIZ PRODTIME 45472.5
RESULTS PROCESSWIZ FOAMYREACTIONS 0.000118753 0.0219913 2.19913e-005
0.000219913 2.19913e-006
RESULTS PROCESSWIZ VELOCITYFOAMY TRUE
RESULTS PROCESSWIZ CHEMMODEL -1
RESULTS PROCESSWIZ CHEMDATA1 TRUE FALSE TRUE TRUE FALSE 0 3 FALSE FALSE
RESULTS PROCESSWIZ CHEMDATA2 0.075 -99999 0 1 0 5 0.9 180 -99999 0 0
RESULTS PROCESSWIZ CHEMDATA3 2.65 0 0.1 0.1 0.1 0.1
RESULTS PROCESSWIZ FOAMDATA FALSE TRUE FALSE 80 14.6923 62.06 1.386 0.693
693 13.86 0 0.02 0.35
RESULTS PROCESSWIZ TABLEFOAMVISC 0 0.02 0 1 0.1 20 0.2 40 0.3 45 0.4 48
0.5 49 0.6 15 0.7 10 0.8 5 0.9 2 1 0.02
RESULTS PROCESSWIZ TABLEFOAMVISC 0 0.1 0 1 0.1 160 0.2 170 0.3 180 0.4
205 0.5 210 0.6 220 0.7 150 0.8 48 0.9 20 1 15
RESULTS PROCESSWIZ TABLEFOAMVISC 0 0.2 0 1 0.1 235 0.2 255 0.3 345 0.4
380 0.5 415 0.6 335 0.7 255 0.8 180 0.9 125 1 40
RESULTS PROCESSWIZ FOAMVISCWEIGHT 1 0.1 0.4 1
RESULTS PROCESSWIZ TABLEIFT 0 18.2
RESULTS PROCESSWIZ TABLEIFT 0.05 0.5
RESULTS PROCESSWIZ TABLEIFT 0.1 0.028
RESULTS PROCESSWIZ TABLEIFT 0.2 0.028
RESULTS PROCESSWIZ TABLEIFT 0.4 0.0057
RESULTS PROCESSWIZ TABLEIFT 0.6 0.00121
RESULTS PROCESSWIZ TABLEIFT 0.8 0.00037
RESULTS PROCESSWIZ TABLEIFT 1 0.5
RESULTS PROCESSWIZ IFTSURFACTANT TRUE 8
RESULTS PROCESSWIZ SURFACTCONC 0 0.05
RESULTS PROCESSWIZ TABLEIFTS 0 23.4
RESULTS PROCESSWIZ TABLEIFTS 0.5 5.163
RESULTS PROCESSWIZ TABLEIFTS 0.75 4.356
RESULTS PROCESSWIZ TABLEIFTS 1 3.715
RESULTS PROCESSWIZ TABLEIFTS 1.25 4.102
RESULTS PROCESSWIZ TABLEIFTS 1.5 3.805
RESULTS PROCESSWIZ TABLEIFTS 1.75 3.521
RESULTS PROCESSWIZ TABLEIFTS 2 2.953
RESULTS PROCESSWIZ TABLEIFTS 0 0.17
RESULTS PROCESSWIZ TABLEIFTS 0.5 0.011
RESULTS PROCESSWIZ TABLEIFTS 0.75 0.005
RESULTS PROCESSWIZ TABLEIFTS 1 0.007
RESULTS PROCESSWIZ TABLEIFTS 1.25 0.007
RESULTS PROCESSWIZ TABLEIFTS 1.5 0.056
```

```
RESULTS PROCESSWIZ TABLEIFTS 1.75 0.097
RESULTS PROCESSWIZ TABLEIFTS 2 0.098
RESULTS PROCESSWIZ IFTSURFACTANTSALINITY TRUE 8
RESULTS PROCESSWIZ SURFACTSALINITYCONC 0 0.05
RESULTS PROCESSWIZ TABLEIFTSSALINITY 0 23.4
RESULTS PROCESSWIZ TABLEIFTSSALINITY 15000 5.163
RESULTS PROCESSWIZ TABLEIFTSSALINITY 22500 4.356
RESULTS PROCESSWIZ TABLEIFTSSALINITY 30000 3.715
RESULTS PROCESSWIZ TABLEIFTSSALINITY 37500 4.102
RESULTS PROCESSWIZ TABLEIFTSSALINITY 45000 3.805
RESULTS PROCESSWIZ TABLEIFTSSALINITY 52500 3.521
RESULTS PROCESSWIZ TABLEIFTSSALINITY 60000 2.953
RESULTS PROCESSWIZ TABLEIFTSSALINITY 0 0.17
RESULTS PROCESSWIZ TABLEIFTSSALINITY 15000 0.011
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RESULTS PROCESSWIZ ADSSURF 0 0
RESULTS PROCESSWIZ ADSSURF 0.1 27.5
RESULTS PROCESSWIZ ADSALK 0 0
RESULTS PROCESSWIZ ADSALK 0.1 50
RESULTS PROCESSWIZ ADSPOLYMER 0 0
RESULTS PROCESSWIZ ADSPOLYMER 0.1 50
RESULTS PROCESSWIZ ALKALINECONC 0 0.3 0.6
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RESULTS PROCESSWIZ ADSSURF2 0 0
RESULTS PROCESSWIZ ADSSURF2 0.1 51
RESULTS PROCESSWIZ SALINITYPPM 0 30000 60000
RESULTS PROCESSWIZ ADSSURF3 0 0
RESULTS PROCESSWIZ ADSSURF3 0.1 27.5
RESULTS PROCESSWIZ ADSSURF3 0 0
RESULTS PROCESSWIZ ADSSURF3 0.1 39.5
RESULTS PROCESSWIZ ADSSURF3 0 0
RESULTS PROCESSWIZ ADSSURF3 0.1 51
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RESULTS PROCESSWIZ SALINITY 1000
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RESULTS PROCESSWIZ POLYVISC 0.8177 3.5 5.2 10.8
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RESULTS PROCESSWIZ SALINITYVISC 0.8177 3.5 5.2 10.8
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FALSE TRUE FALSE TRUE TRUE 0.9999
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RESULTS PROCESSWIZ LSWIREACTMINMINTEQ
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RESULTS PROCESSWIZ LSWIAQINIT
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0.708108 0.065 0.708108
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RESULTS PROCESSWIZ BURN
RESULTS PROCESSWIZ CRACK
RESULTS PROCESSWIZ COMPNAMES
RESULTS PROCESSWIZ BLOCKAGE FALSE 4
RESULTS PROCESSWIZ END
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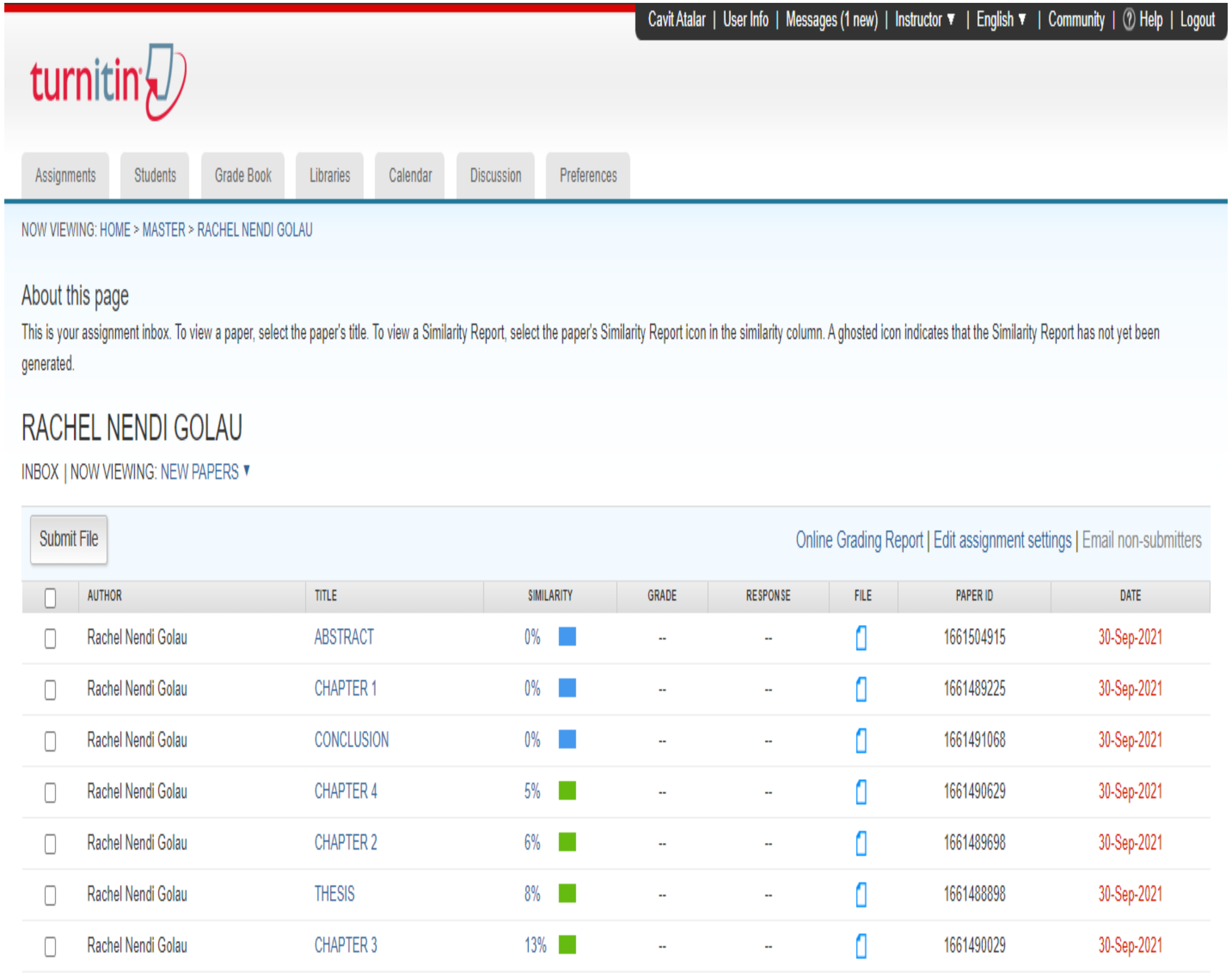
APPENDIX 2

SIMILARITY REPORT



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Prof. Dr. Cavit ATALAR

APPENDIX 3

ETHICAL APPROVAL LETTER

YAKIN DOĞU ÜNİVERSİTESİ

ETHICAL APROVAL DOCUMENT

Date: 31/08/2021

To the **Institute of Graduate Studies**

The research project titled "**NUMERICAL INVESTIGATION OF THE EFFECT OF CARBON SEQUESTRATION IN THE WATER ZONE OF A HYDROCARBON RESERVOIR**" has been evaluated. Since the researcher will not collect primary data from humans, animals, plants or earth, this project does not need through the ethics committee.

Title: Prof. Dr.

Name Surname: Cavit ATALAR

Signature:

Role in the Research Project: Supervisor