CARBON DIOXIDE SEQUESTRATION AND ENHANCED OIL RECOVERY CO-OPTIMIZATION

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ABSTRACT

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The worldwide growth of industry leads to continuous rise of anthropogenic emission amount into the atmosphere, which causes greenhouse effect all over the world, that is heating up the atmosphere and changing the global climate. On the other hand, carbon dioxide injection into oil reservoirs for the purpose of enhancement of oil recovery (CO_2-EOR) has been commercially used for nearly 50 years. The operations in petroleum sector are being carried out in a way to maximize the recovered oil while keeping the amount of CO_2 injected at its minimum due to the purchase cost of carbon dioxide. To overcome the economic restrictions for CO_2 sequestration during EOR, it is necessary to simultaneously maximize economic oil recovery and the volumes of CO_2 injected in oil reservoirs using an engineering approach. This process is named as co-optimization. For this purpose, several simulations for different scenarios are being carried out to find the maximum amount of CO_2 that can be stored, maximum amount of oil that can be produced, and an optimal point for simultaneous maximization of both numbers.

Results show, that using inverted 5 spot pattern and implementing water-alternating-gas (WAG) injection can significantly contribute to the co-optimization, while other parameters, such as pattern area and injection rate need to be evaluated on case by case basis, considering economical factors as well.

Keywords: Climate Change, CO_2, Storage, Sequestration, Enhanced Oil Recovery, Co-Optimization

ÖZ

KARBON DİOKSİTİN DEPOLANMASI VE GELİŞMİŞ PETROL KURTARIMININ BİRLİKTE UYGULANMASI

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Yüksek Lisans, Petrol ve Doğal gaz Mühendisliği
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Endüstrinin dünya çapında büyümesi, atmosfere yapılan insan kaynaklı emisyon miktarlarının sürekli artmasına neden olmakta, bu da tüm atmosferi ısıtan ve küresel iklimi değiştiren sera etkisini doğurmaktadır. Öte yandan, petrolün geri kazanımı amacıyla (CO_2-EOR) petrol rezervuarlarına karbondioksit enjeksiyonu yaklaşık 50 yıldır ticari olarak kullanılmaktadır. Petrol sektöründeki çalışmalar, satın alma maliyetinin yüksek olması nedeniyle enjekte edilen CO_2 miktarını minimumda tutarken geri kazanılan petrolü maksimuma çıkaracak şekilde yürütülmektedir. EOR sırasında CO_2 sekestrasyonuna yönelik ekonomik kısıtlamaların üstesinden gelmek amacı ile, bir mühendislik yaklaşımı kullanarak ekonomik petrol geri kazanımını ve petrol rezervuarlarına enjekte edilen CO_2 hacimlerini eş zamanlı maksimize etmek gerekmektedir. Ortak optimizasyon adı verilen bu işlemin amacı, depolanabilecek maksimum CO2 miktarını, üretilebilecek maksimum petrol miktarını ve her iki sayının eş zamanlı olarak maksimizasyonu için en uygun noktayı bulmak amacıyla farklı senaryolar için çeşitli simülasyonlar gerçekleştirilmektedir.

Sonuçlar, tersine çevrilmiş 5 nokta deseninin kullanılmasının ve su-alternatif gaz (WAG) enjeksiyonunun uygulanmasının, eş optimizasyona önemli ölçüde katkıda bulunabileceğini gösterirken, desen alanı ve enjeksiyon hızı gibi diğer parametrelerin durum bazında ekonomik faktörleri de göz önünde bulundurarak değerlendirilmesi gerektiğini göstermektedir.

Anahtar Kelimeler: İklim Değişikliği, CO_2, Depolanma, Ayrılma, Gelişmiş Petrol Kurtarımı, Ortak Optimizasyon

To My Father

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TABLE OF CONTENTS

CHAPTERS

APPENDICES

LIST OF TABLES

TABLES

LIST OF FIGURES

FIGURES

LIST OF ABBREVIATIONS AND NOMENCLATURE

ABBREVIATIONS

ASP	Alcaline-Surfactant-Polymer
ASU	Air Separation Unit
CCO2	Continuous CO2
CCS	Carbon Capture and Storage
CCU	Carbon Capture and Utilization
CCUS	Carbon Capture, Utilization and Storage
CHOPS	Cold Heavy Oil Production with Sand
CMG	Computer Modelling Group
CO2-EOR	CO2 Enhanced Oil Recovery
CO2-WAG	CO2 water-alternating gas
ECBM	Enhance Coalbed Methane
EOR	Enhanced Oil Recovery
FCM	First-Contact Miscible
Gt	Giga ton
HC	Hydrocarbon
IFT	Interfacial Tension
IGCC	Integrated Gasification Combined Cycle
MCM	Multiple-Contact Miscible

MEA	Monoethanolamine
MMP	Minimum Miscible Pressure
NGCC	Natural Gas-Fired Combined Cycle
PC	Pulverised Coal
PCC	Post-Combustion Capture
Pg	Peta gram
RF	Recovery Factor
SAGD	Steam Assisted Gravity Drainage
UNFCCC	United Nations Framework Convention on Climate Change
WAG	Water Alternating Gas

NOMENCLATURE

ω	mixing parameter
F	partitioning function
S	saturation, fraction
B	formation volume factor, RB/STB
k	permeability, md
k_r (k_{rp})	relative permeability, fraction
P_c	capillary pressure, psi
P	pressure, psi
μ	viscosity, cp

ρ	density, mass/volume
γ	oil specific gravity
T	temperature (F)
MW	oil molecular weight

Subscripts

rp, r	relative
o	oil
w	water
g	gas
sol	solvent (CO_2)
i	initial
s	saturation
liq	liquefaction

Superscripts

eff	effective
m	miscible
Im	Immiscible
Frac	Fraction

CHAPTER 1

INTRODUCTION

Global climate change has been a huge issue for a long time. It is stated, that one of the major causes of this change is increasing amount of greenhouse gases emissions, which include: Carbon Dioxide (CO_2), Methane (CH_4), Nitrous Oxide (N_2O), Hydrofluorocarbons (HFCs), Perfluorocarbons (PFCs) and Sulphur hexafluoride (SF_6) (United Nations Climate Change, 2019b). These gases are affecting atmosphere insulation which results in the Earth keeping the warmth more than it was before the increase (Ansarizadeh et al., 2015). The concentration of CO_2 has reached 385ppm in 2008 starting with 280ppm in preindustrial era and continues to increase with the rate of 2ppm each year (Bouzalakos, 2010). Major reasons behind this increase are fossil fuel combustion, processes going on in cement plants, and deforestation (Lal, 2010). As the result, the global temperature average has increased for about 0.85 °C between 1880 and 2012 (IPCC, 2014).

Starting with the Kyoto protocol for the two commitment periods, and then continuing with Paris Agreement with one commitment period, countries all over the world are trying to reduce the amount of anthropogenic greenhouse gases in the atmosphere, and to mitigate their effect on climate change (United Nations Climate Change, 2019b, 2019a). Global trend of carbon dioxide management usually relies on three different strategies. The first one, is switching to the low-carbon energy sources, such as alternatives and renewables. The second, developing and applying new technology in order to increase efficiency of conventional energy sources. Finally, third strategy is to apply Carbon Capture, Utilization and Storage (CCUS) techniques to decrease the amount of emitted CO_2 (Bouzalakos, 2010). Since most of world energy sources are fossil fuels, rapid transition to low-carbon energy sources is not technically and economically feasible. So, at the moment, the major method of CO_2 mitigation is considered to be CCUS (Ansarizadeh et al., 2015). Applying CCUS is the way to enable continuous use of conventional energy sources (fossil fuels), while decreasing the amount of CO_2 in the atmosphere (IRGC, 2008). CCUS consists of several steps applied in the process: Capturing CO_2 from exhaust gases, pressurizing and transporting to the storage or utilization site, and finally sequestration or utilization process (Bouzalakos, 2010). With these technologies approximately 60% of world CO_2 emissions that are being resulted by stationary sources operations can be mitigated (Ansarizadeh et al., 2015).

At the moment, one of the most effective ways for carbon sequestration is storing it in geological formation, which can also be called geosequestration. This also involves the usage of hydrocarbon reservoirs and deep saline aquifers. Unfortunately, cost of CCUS is quite high at the moment. It is estimated, that around 2020 average cost of the project per tonne of CO_2 abated was in the range of 35–50€, which is not economically feasible for most of the companies to implement (Bouzalakos, 2010). On the other hand, there is an established practice of CO_2 usage for enhanced oil recovery (EOR) purposes. New technologies available in EOR operations provide opportunities for combination of the process with carbon dioxide sequestration, thus utilizing CO_2 for enhanced oil recovery and then storing it in oil reservoir (Gaspar Ravagnani et al., 2009). The advantage of this method is that the cost of carbon sequestration decreases due to profit available from additional oil production. Furthermore, field that has already been submitted to EOR applications before, can be even more cost effective, since it already has most of the required infrastructure required for gas injection into the reservoir. There are three ways to implement CO_2-EOR in combination with carbon storage: conventional, which mainly focuses on EOR, rather than CO_2 storage; advanced, in which operator is trying to utilize and store more carbon dioxide, while increasing oil recovery; and maximum storage case, when CO_2-EOR is mainly focused on CO_2 sequestration, rather than oil recovery(IEA, 2015). While there has not been a lot of experience in usage of CO_2-EOR for carbon dioxide storage, the IEAGHG Weyburn-Midale CO_2 Monitoring and Storage Project, which was implemented between 2000 and 2012, provided evidence, that both EOR and CO_2 sequestration can be co-optimized, and permanent storage of carbon dioxide is achievable in the process(IEA, 2015).

Currently CO_2 is injected either only focusing on EOR, disregarding amount of CO_2 stored, or disregarding oil recovery and only focusing on CO_2 sequestration.

The purpose of this study, is the co-optimization of both EOR and sequestration and finding an optimal way for the process in heavy oil field. The approach includes the implementation of reservoir simulations to this study. The simulations include various cases of CO_2 injection patterns, well spacing, injection rates, zones injected, and feasibility of using Water-Alternating-Gas injection for this purpose. The reservoir modeling is performed by using CMG's IMEX, Builder and Results software.

CHAPTER 2

LITERATURE REVIEW

2.1 Greenhouse gases and climate change

According to scientists the global warming trend is attributed to the greenhouse effect, which is the result of Earth heat being trapped by the atmosphere (NASA, n.d.). Major gases, that prevent heat from escaping to space are: Carbon Dioxide (CO_2), Methane (CH_4), Nitrous Oxide (N_2O), Hydrofluorocarbons (HFCs), Perfluorocarbons (PFCs) and Sulphur hexafluoride (SF_6) (United Nations Climate Change, 2019b). CO_2 is the major forcing element of global warming. Its concentration in the atmosphere has increased by more than 30% since the beginning of industrial revolution (NASA, n.d.). As it can be seen on Figure 2.1 and 2.2, the concentration of CO_2 has reached 385ppm in 2008 starting with 280ppm in preindustrial era and continues to increase with the rate of 2ppmv each year (Bouzalakos, 2010).

The following are considered as the sources of carbon dioxide: naturally induced CO_2 coming from the processes such as volcano eruptions and respiration, and human induced CO_2, from changes in land usage, producing energy from fossil fuels, and deforestation. It was stated by 1300 experts from different countries, that there is 95% probability, that the increase in global temperature over the past 50 years was caused mainly by human activities, resulting in greenhouse gases emission (IPCC, 2014). Over the past century, concentration of carbon dioxide has increased significantly mainly due to fossil fuel burning processes (NASA, n.d.).

Due to this increase, as it can be seen on the Figure 2.3, the global temperature average has increased for about 0.85 °C between 1880 and 2012 (IPCC, 2014; NASA, n.d.).

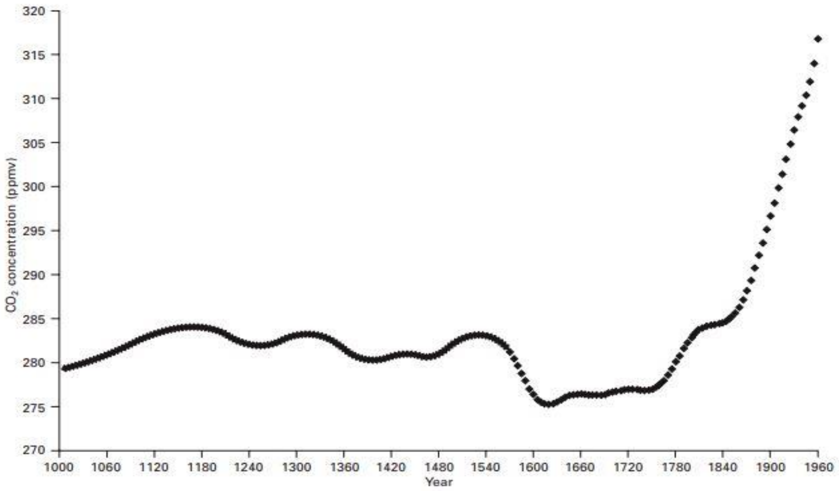


Figure 2.1. Average annual atmospheric CO_2 concentrations from Antarctic ice and firn from 1010–1960 (Bouzalakos, 2010)

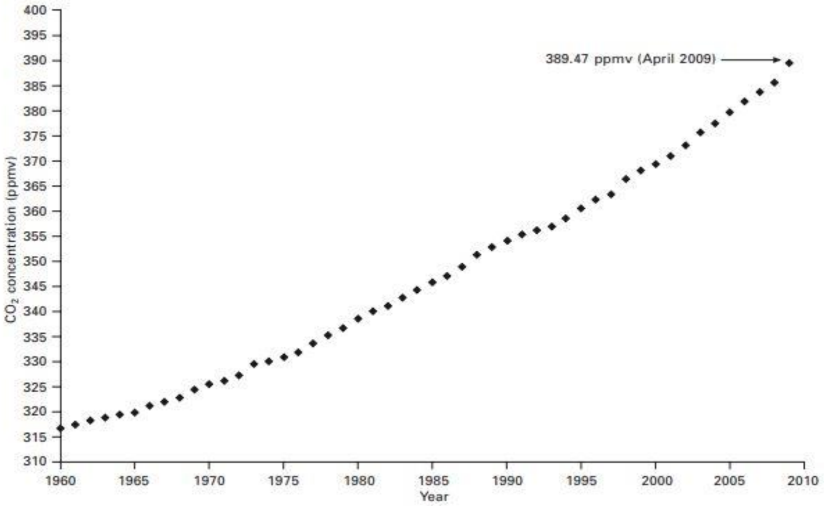


Figure 2.2. Average annual atmospheric CO_2 concentrations based on direct measurements at Mauna Loa Observatory (Bouzalakos, 2010)

also used for fuels generation by implementing various processes, such as Fischer–Tropsch process. Still, most of these processes are not suitable for long time decrease in CO_2 amounts, since these chemicals and fuels have short life span, and in the end used carbon dioxide is still emitted into the atmosphere. This is the precursor for further research in using CO_2 for synthesis of materials with longer lifespan, such as mineral carbonates, obtained through the process also called mineral carbonation (Cuéllar-Franca & Azapagic, 2015).

Mineral carbonation is the process carbonates are formed by reaction of carbon dioxide with metal oxides. Carbonates that are formed through this process can be used in construction and provide long time storage of CO_2 used in the process. However, this technology requires further development, since the cost of the process is high, and makes it not economically feasible (Cuéllar-Franca & Azapagic, 2015).

Using carbon dioxide for microalgae cultivation, which is being used in biofuels production, is another utilization method, that is worth mentioning. Microalgae are able to take CO_2 and nitrogen directly from waste streams. Unfortunately, large-scale usage of microalgae for biofuels production is not economically feasible, due to high production costs and energy requirements (Cuéllar-Franca & Azapagic, 2015).

2.2.3 Carbon storage

Carbon sequestration can be described as long-term storage of CO_2 (Kambale & Tripathi, 2010). Various options for carbon dioxide storage are currently available. Major global pools for carbon sequestration are: geologic, terrestrial, biosphere and oceanic (Bouzalakos, 2010; Kambale & Tripathi, 2010).

There are several major properties that should be considered before CO_2 storage (Kambale & Tripathi, 2010):

- The storage period should be long enough for efficient reduction in carbon dioxide concentration in the atmosphere
- The overall sequestration process should be economically feasible, that is its cost should be minimized
- All precautions should be taken to minimize risk of any kind of accident
- There should be no or minimal impact on environment
- No national or international laws and regulations should be violated by the process

Basically carbon sequestration can be divided into two major groups: biotic and abiotic (Kambale & Tripathi, 2010). Figure 2.8 illustrates major classification of carbon sequestration.

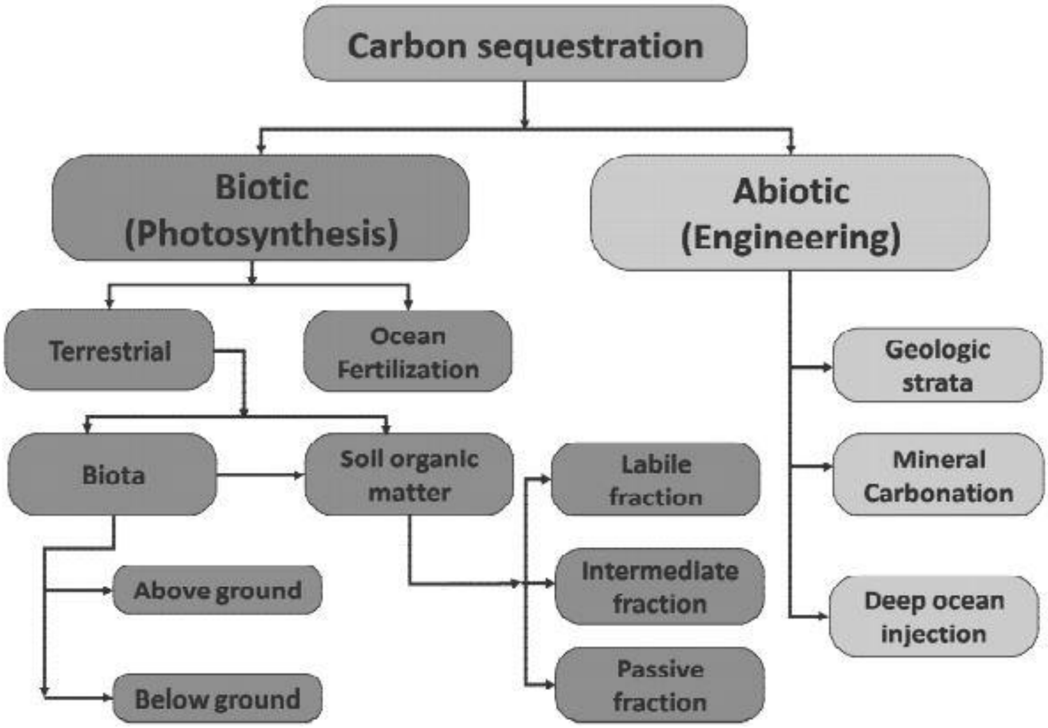


Figure 2.8. Carbon sequestration classification (Kambale & Tripathi, 2010)

Biotic carbon sequestration is based on converting carbon dioxide into sugars, carbohydrates, celluloses and lignins by the process called photosynthesis. Basically, CO_2 in atmosphere is sequestrated in terrestrial and aquatic carbon pools (Bouzalakos, 2010). As it can be seen from the Figure 2.8, biotic sequestration can be further divided into terrestrial and ocean sequestrations, with terrestrial including its own smaller subgroups.

Abiotic carbon sequestration is CO_2 without any kind of biological activity involved. It includes sequestration in geological formations (geosequestration), ocean, and by mineral carbonation, which was discussed in chapter 2.2.2.

2.2.3.1 Terrestrial sequestration

Terrestrial sequestration can be described as carbon storage in biomass both aboveground and belowground, and in soil carbon as soil/organic matter and inorganic carbon. These methods have the capability of storing carbon dioxide in forests and soils for centuries (Post et al., 2009). Terrestrial carbon pool is the third largest global carbon dioxide pool. It is estimated, that terrestrial pool to contain about 2850 Pg of carbon. Theoretically sequestration potential in terrestrial pool can be estimated as 6-10 Pg C/year, while the widely accepted technical potential is 3 Pg C/year (Lal, 2010).

The sequestration system described above has numerous benefits when considering ecosystem services. These can be: agronomic productivity increase, food security and water quality improvement, and biodiversity enrichment. Considering all these benefits, terrestrial carbon sequestration can be considered as a win-win method as it helps to reduce anthropogenic CO_2 in the atmosphere and improve the ecosystem simultaneously (Lal, 2010).

2.2.3.2 Ocean sequestration

Ocean carbon pool is the largest among global pool of carbon with approximately 40,000 Pg of carbon. It is stated, that deep ocean is unsaturated when considering CO_2. It has been estimated, that injecting all anthropogenic carbon dioxide, that would double the concentration in the atmosphere will increase the concentration of carbon in ocean by just 2%. It should be also noted; that ocean is not isolated from the atmosphere. Considering long time period, 1000s of years, 80% of today's anthropogenic carbon dioxide will eventually be naturally sequestrated in the ocean. Implementing ocean sequestration methods will just accelerate the natural process, which will be beneficial for climate and environment (Kambale & Tripathi, 2010).

There are both biotic and abiotic methods for ocean carbon sequestration.

Biotic method is ocean fertilization with some nutrients, such as iron, to stimulate the growth of marine phytoplankton, which in result will increase the uptake of atmospheric carbon. It is assumed, what the carbon will remain in the ocean with the phytoplankton eventually sinking to the deep ocean. The experiments conducted in the ocean show, that addition of iron to the ocean increases phytoplankton biomass significantly. However, the effectiveness of this sequestration method is not proved. For effective sequestration, the carbon has to be transported to the deep ocean. Until now no experiments have been conducted to determine this transfer efficiency (Kambale & Tripathi, 2010).

Abiotic method is focused on direct injection of CO_2 into deep ocean. The injection depth should be at least 500 m, which corresponds to 5 MPa hydrostatic pressure and 4 °C temperature. At these conditions carbon dioxide is in liquid phase. At the depth less than 500 m, the CO_2 will vaporize and escape the ocean (Golomb & Pennell, 2010). At the depth between 500m and 3000 m, the density of carbon dioxide is less than the one of the seawater, which results in CO_2 being ascended by the buoyancy. At any depth greater than 3000 m, the carbon dioxide becomes heavier than seawater, resulting in its dropping to the bottom of the ocean and forming a, so called, "CO_2 lake" (Kambale & Tripathi, 2010).

Even though there is great potential for oceanic carbon sequestration, there is strong opposition of this method by marine biologists and environmental groups. The main concern is possible acidification of large volumes of seawater because of the formation of carbonic and bicarbonic acid. Another constraint for this method are international regulations which prohibit dumping of industrial waste into the ocean, which may also include anthropogenic CO_2. Several proposals have been made that could result in minimizing of acidification. However, further studies are required to determine their feasibilities (Golomb & Pennell, 2010).

2.2.3.3 Geosequestration

Geosequestration, or geological sequestration, can be described as capture, transportation, and injection of carbon dioxide to underground deep rock formations for long-time storage (Metz et al., 2005). Geologic carbon pool is the second largest among global carbon sinks, with up to 10000 Pg carbon (Lal, 2010). The process of CO_2 storage in geological formation has been naturally going for hundreds of millions years. CO_2 that is produced by biological and igneous activities, and some chemical reactions is accumulated in natural underground formations in various forms (Metz et al., 2005).

There are several potential sinks for underground carbon dioxide storage: deep saline formations and aquifers, oil and gas reservoirs, and deep unmineable coal seams. At the moment, deep saline aquifers are considered to have the highest potential for sequestration, however their capacity and suitability of properties is still under discussion (Bouzalakos, 2010). On the other hand, oil and gas reservoirs are considered as the first choice for carbon dioxide injection due to the advantage provided by the possibility of combining storage with CO_2 enhanced oil recovery (CO_2-EOR). This will result in increase in overall storage capacity and decrease in cost of sequestration due to additional oil production (Bachu, 2010; Bouzalakos, 2010). As for the coal seams, there is potential for storage combined with enhanced methane production, but further studies of this subject are required (Bouzalakos, 2010). It should also be noted, that continental shelf and some adjacent deep-marine sedimentary basins can be considered as potential carbon storage formation, however most of these sediments are too thin and impermeable for the sequestration. There has also been some considerations of using salt caverns, basalt and shales (organic rich) for the storage (Metz et al., 2005).

2.2.3.3.1 Coal seams

Coal seams can be characterized as fractured porous media, with large internal surface area. Methane (CH_4) is generated and retained in the coal formation during some geological processes are going on, in the formation of coal seams, through the process called coalification. In coal seams, gas not only fills fractures and pores, but also is adsorbed to the coal surface, and absorbed into its structure. Since adsorbed methane is of a much higher density than gas, reservoir rock has better capacity for CO_2 storage (Mazzotti et al., 2010).

Storage capacity of coal seams is relatively smaller compared to other geological storage pools. Still, formations promising economically feasible mining potential have been considered as possible storage sinks for carbon dioxide. Even though the worst case scenario suggests that storage potential of these reservoirs are much smaller than the one of other geological formations, compared to the current rate of anthropogenic emissions, which is approximately 30 Gt CO_2 /year, these amounts should still be taken into consideration as means of greenhouse effect mitigation (Mazzotti et al., 2010).

The trapping mechanisms, that are containing carbon dioxide inside the coal seams are: first, stratigraphic and structural, which is basically free phase in fractures and pores; second, hydrodynamic, which is CO_2 dissolved in water; and third, adsorption on the coal surface, which is dominant during storage (Ibrahim & Nasr-El-Din, 2015).

At the moment, main approach of carbon sequestration in coal seams is enhance coalbed methane (ECBM) recovery, which results in economically profitable production from coal seams. This can be achieved by carbon dioxide injection at supercritical conditions. The method is currently being studied to improve the understanding of sorption and displacement processes. The pilot tests that were conducted have demonstrated technical feasibility of carbon dioxide injection into the coal seams, for simultaneous CH_4 recovery and CO_2 storage. However, further research is required for full realization of storage potential (Mazzotti et al., 2010).

2.2.3.3.2 Deep saline aquifers

Deep saline aquifers can be defined as underground formations filled with water. They are very important in terms of carbon sequestration, since they are widely distributed across the globe, commonly have high volumes, and are capable of storing CO_2 for long time periods. Due to usual high permeability values, these storage sites are capable of producing and injecting fluids at high rates. Even though, that storage capacity is often accepted as very large, there are a lot of uncertainties related to properties of the reservoir, and flow regimes (Rosenbauer & Thomas, 2010).

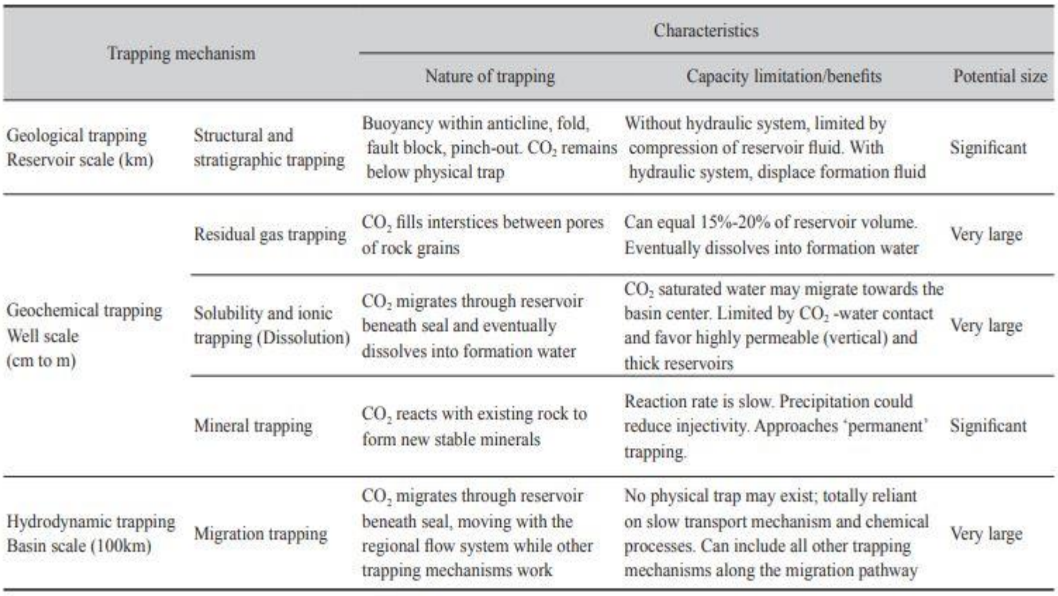
To evaluate potential of deep saline aquifers for storage, several factors, such as: total capacity, ease of injection, and environmental and human health risks; should be considered. Furthermore, to calculate net pore volume of the formation, create groundwater and carbon dioxide flow maps, and calculate hydrostatic potential, some physical and chemical properties have to be evaluated. Among these are: temperature and depth with regards to depth, mineralogy, grainsize, porosity and permeability, reservoir structure and thickness, composition of fluid in place, and confinement of the reservoir (Rosenbauer & Thomas, 2010).

Preferable saline formations for carbon storage are required to have a low permeability cap rock above the reservoir. It is essential, since the cap rock prevents the migration of injected CO_2 back to the atmosphere. Another preferable parameter is the depth that should vary between 800 m and 3000 m, where geologic parameter are most favorable for carbon dioxide storage (De Silva et al., 2015).

There are several trapping mechanisms for carbon storage in deep saline aquifers. These mechanisms can be classified into three major groups: geological trapping, geochemical trapping, and hydrodynamic trapping. Each of these groups has several trap mechanisms described in Table 2.2 (Yang et al., 2010).

Considering the future of deep saline sequestration, pilot and commercial sequestration projects, such as Snohvit, Sleipner, In Salah, Gorgon, proved that this method is technologically feasible. Still, there are several aspects, such as costs, environment, legal framework, and acceptance by people, that should be taken into account (Michael et al., 2010; Rosenbauer & Thomas, 2010).

Table 2.2 Characteristics of trapping mechanisms in saline aquifers (Yang et al., 2010)



Trapping mechanism		Characteristics		
		Nature of trapping	Capacity limitation/benefits	Potential size
Geological trapping Reservoir scale (km)	Structural and stratigraphic trapping	Buoyancy within anticline, fold, fault block, pinch-out. CO_2 remains below physical trap	Without hydraulic system, limited by compression of reservoir fluid. With hydraulic system, displace formation fluid	Significant
Geochemical trapping Well scale (cm to m)	Residual gas trapping	CO_2 fills interstices between pores of rock grains	Can equal 15%-20% of reservoir volume. Eventually dissolves into formation water	Very large
	Solubility and ionic trapping (Dissolution)	CO_2 migrates through reservoir beneath seal and eventually dissolves into formation water	CO_2 saturated water may migrate towards the basin center. Limited by CO_2 -water contact and favor highly permeable (vertical) and thick reservoirs	Very large
	Mineral trapping	CO_2 reacts with existing rock to form new stable minerals	Reaction rate is slow. Precipitation could reduce injectivity. Approaches 'permanent' trapping.	Significant
Hydrodynamic trapping Basin scale (100km)	Migration trapping	CO_2 migrates through reservoir beneath seal, moving with the regional flow system while other trapping mechanisms work	No physical trap may exist; totally reliant on slow transport mechanism and chemical processes. Can include all other trapping mechanisms along the migration pathway	Very large

2.2.3.3.3 Oil and gas reservoirs

Currently oil and gas reservoir are main candidates for geosequestration and there are several reasons for that. First, it is known, that hydrocarbon reservoirs are capable of containing large volumes of fluids for long time periods. Second, most of the reservoirs have already been well characterized both in terms of formation rock and formation fluids. Third, the facilities and equipment that were used for hydrocarbon production can be converted to CO_2 injection needs, which will significantly decrease overall cost of the project. Finally, if the field is still in production phase, carbon storage can be combined with EOR applications, which will make the project even more (economically) feasible, due to additional oil production (Bachu, 2010; Le Gallo et al., 2002). It is also worth mentioning that the surface facilities created for CO_2-EOR or carbon storage in hydrocarbon reservoir can be further used for later saline aquifers sequestration (Vega & Kovscek, 2010).

It is usually stated, that 800 m is the minimum required depth for CO_2 injection and storage in the underground geological formations. While it is true for most of the cases, shallower reservoir should not be rejected right away if other requirements, such as capacity, confinement, risks for environment and health, and social acceptance are met. While selecting storage site another important parameter that should be considered is time of availability. Some reservoirs are not suitable for carbon sequestration during the production period. Absence of strong aquifer is another criterion, that can be an advantage for the storage project. If strong aquifer support exists in the system, water will migrate to the hydrocarbon reservoir, as oil and gas are produced, consequently reducing the overall storage capacity of the pool. Same is also suitable for fields that had undergone major water and gas flooding (Bachu, 2010).

CO_2 has been injected into the oil reservoirs for a long time now. Even though depleted oil reservoir provides great potential for carbon storage in terms of capacity, combination of CO_2-EOR and sequestration is preferred for economical reasons.

There are several aspects that should be considered before simultaneous CO_2-EOR and storage. First, it is reservoir seals' integrity. Overpressurization of pore fluid may result in damage to the reservoir barriers. Some other risks are related to the integrity of old wells' barriers such as casings and cement plugs. Studies should be conducted prior to injection to prevent leakage through fractures in the barriers (Vega & Kovscek, 2010).

Common practice for CO_2-EOR is water alternating gas (WAG) injection, which alternated water and carbon dioxide injection in sequential way. However, this method is not suitable for EOR-storage co-optimization, since large water volume injection significantly reduces the capacity of the reservoir. For proper co-optimization of these processes it is required to reduce injected water amount as much as possible and establish high quality well control to prevent back production of injected gas. Simulation conducted by Kovscek and Cakici (2005) shows that in terms of oil recovery both immiscible CO_2-EOR and WAG are similar. However, the capacity for storage is much higher with immiscible carbon dioxide injection. They have also shown that miscible CO_2 injection can provide same storage volume as immiscible (Vega & Kovscek, 2010).

As for natural gas reservoirs, there have not been any significant CO_2 injections. However, studies show that production acceleration can be achieved by reservoir re-pressurization while carbon dioxide injection. The advantage of carbon dioxide flooding in natural gas reservoirs, is that injected gas is denser and more viscous than the fluid in place, enabling uniform sweeping (Vega & Kovscek, 2010).

Carbon sequestration in unconventional oil and gas reservoirs is a point of interest for current sequestration studies. Conducted laboratory tests show that immiscible CO_2 injection into the unconventional shale rock formation is technically feasible to be used as enhanced oil production tool, which leads us to possible future storage sites (Vega & Kovscek, 2010).

There are correlations for determining carbon dioxide solubility, oil swelling and oil viscosity, developed by Emera and Sarma (Perera et al., 2016).

So, for super-critical conditions, the CO_2 solubility can be determined using the following correlation:

$$\mathrm{CO_2\ Solubility}\left(\frac{\mathrm{mol}}{\mathrm{mol}}\right) = 2.238 - 0.33y + 3.23y^{0.6474} - 4.8y^{0.25656} \quad (2.1)$$

$$\text{With } y = \gamma\left(\frac{\mathrm{T}^{0.8}}{P_{\mathrm{s}}}\right)\exp\left(\frac{1}{MW}\right) \quad (2.2)$$

As for the sub-critical conditions, the correlation is as follows:

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

(2.3)

$$\text{With } y = \gamma\left(\frac{P_{\mathrm{s}}}{P_{\mathrm{liq}}}\right)\exp\left(\frac{1}{MW}\right) \quad (2.4)$$

γ is the oil specific gravity (oil density at 15.6 °C), T is the temperature (F), P_s is the saturation pressure (psi), P_{liq} is the CO_2 liquefaction pressure at the specified temperature (psi), MW is the oil molecular weight, and μ_i is the initial dead oil viscosity at the specified temperature (cp).

2.3.2.2 Oil swelling

Usually oil swelling is determined by using the following equation:

$$\text{Oil swelling factor } = \left(\frac{\text{Saturated } \mathrm{CO_2} \text{ volume at current T}}{\text{Oil volume at current T}}\right) \quad (2.5)$$

In addition to carbon dioxide solubility, oil molecules' size has effect on oil swelling (Perera et al., 2016).

Apart from equation 2.5, following correlations can be used to determine oil swelling factor (Emera & Sarma, 2007):

Molecular weight of hydrocarbon higher or equal to 300:

Swelling factor $= 1 + 0.3302y - 0.8417y^2 + 1.5804y^3 - 1.074y^4 + 0.0318y^5 - 0.21755y^6$ (2.6)

Molecular weight of hydrocarbon lower than 300:

Swelling factor $= 1 + 0.48411y - 0.9928y^2 + 1.6019y^3 - 1.2773y^4 + 0.48267y^5 - 0.06671y^6$ (2.7)

With $y = 1000\left\{\left(\frac{\gamma}{MW}\right)[\mathrm{CO_2\ solubility}\ ]^2\right\}^{\exp\left(\frac{\gamma}{MW}\right)}$ (2.8)

γ is the oil specific gravity (oil density at 15.6 ″C) and MW is the oil molecular weight.

2.3.2.3 Oil viscosity

In addition to carbon dioxide solubility, oil viscosity during Immiscible-CO_2 EOR is dependent on pressure. So, as saturation pressure increases, viscosity decreases until the pressure reaches liquefaction value, after which it starts to rise as the result of pressure and oil compressibility (Emera & Sarma, 2007).

Following equation can be used to determine oil viscosity during Immiscible-CO_2 EOR:

Oil viscosity $= y\mu_\mathrm{i} - 10.8\left(\frac{\mathrm{CO_2\ solubility}}{\mu_\mathrm{i}}\right)$ (2.9)

With $y = x^{-0.74}$ and $x = \left[\mu_\mathrm{i}\left(\frac{P_\mathrm{s}}{\mu_\mathrm{i}}\right)^{0.2}\right]^{\frac{\gamma}{\mathrm{CO_2\ solubility}}}$ (2.10)

P_s is the saturation pressure (psi), and μ_i is the initial dead oil viscosity at the specified temperature (cp).

CHAPTER 3

STATEMENT OF THE PROBLEM

The concentration of CO_2 in the atmosphere has been increasing rapidly for the past century due to high anthropogenic gas emissions. This increase has an adverse effect on environment and leads to global warming. One way of climate change mitigation is carbon sequestration in geological formations, particularly in oil reservoirs.

History of carbon dioxide injection into oil reservoirs lasts for several decades. However, the operations in petroleum sector are being carried out in a way to maximize the recovered oil while keeping the amount of CO_2 injected at its minimum due to the cost of purchase of carbon dioxide. On the other hand, full scale implementation of carbon storage is expensive, which leads to economic restrictions in the implementation phase. To overcome this problem, and make carbon sequestration more appealing, it is necessary to change the way operations are conducted in petroleum sector, by simultaneously maximizing economic oil recovery and the volumes of CO_2 injected and stored in oil reservoirs by using an engineering approach. This process is named as co-optimization.

This study is focused on evaluation of different methodologies that can be applied to recover as much oil as possible while increasing injected CO_2 amounts at the same time. So, parameters, such as injection well pattern, pattern area, CO_2 injection rate, injection zone, and evaluating WAG injection, their effects on both hydrocarbon recovery and CO_2 storage have been observed and analyzed. Reservoir simulation studies have been performed with different scenarios in order to find the co-optimized processes in heavy oil fields. CMG’s IMEX in combination with Builder and Results is used to carry out modeling and simulation.

CHAPTER 4

METHODOLOGY

This study uses numerical modeling to understand how various reservoir development and carbon sequestration strategies affect both HC production and CO_2 deposition and to conclude which ones are more suitable for production, sequestration or technical optimum between the two. The reservoir modeling and development simulations are done using CMG’s Black Oil and Unconventional Simulator called IMEX.

4.1 CMG IMEX and Pseudo-Miscible Model

IMEX is CMG’s, black oil simulator. It is capable of modeling reservoirs of various structural complexity, different grid sizes and types, and various fluid types. It is able to use either combination of implicit and explicit calculating methods or just implicit for faster calculations. In combination with Builder, it is a user friendly modeling/simulating software which is often used for simulating unconventional reservoirs, and both secondary and tertiary recovery of hydrocarbons. (CMG, 2019).

One of the precursors for using IMEX black oil simulator in this study, is its ability to simulate pseudo-miscible solvent injection, which in our case is CO_2. Main advantage of this option is no requirement for chemical analysis of reservoir fluids in terms of composition(Computer Modelling Group, 2018) thus making this method faster and more efficient than compositional simulations (Hughes, 2010). This simulating method was developed by Todd and Longstaff in 1972 to simulate miscible displacement by using black oil model without requirement for detailed compositional analysis of the fluids. The mixing parameter (ω) which represents the mixing of fluids with 0 being fully immiscible and 1 fully miscible(Todd & Longstaff, 1972).

Using pseudo-miscible model requires modifications to several equations which include: relative permeability, viscosity, density, capillary pressure.

$$k_{rp}^{eff} = \frac{\omega_{o(P)}}{\omega_{o\,max}} k_{rp}^{m} + \left(1 - \frac{\omega_{o(P)}}{\omega_{o\,max}}\right) k_{rp}^{Im} \tag{4.1}$$

Where:

p = oil, solvent, gas

Miscible portion of effective relative permeability: $k_{rp}^{m} = F_p^{m} k_{row}(S_w)$ (4.2)

With F_p^{m}being a partitioning function for $k_{row}(S_w)$ based on each hydrocarbon's phase weighted saturation.

Immiscible portion of effective relative permeability:

$$k_{rp}^{Im} = k_{ro}(S_w, S_L) \tag{4.3}$$

With $S_L = S_o + S_w$, k_{ro}= immiscible three phase relative permeability and p = oil.

$$k_{rp}^{Im} = F_p^{Im} k_{rg}\left(S_g + S_{sol}\right) \tag{4.4}$$

With F_p^{Im}being a partitioning function for $k_{rg}\left(S_g + S_{sol}\right)$ based on gas and solvent's saturations

As for the Miscible and Immiscible Partitioning Functions ($F_p^{m}$and F_p^{Im} accordingly),they are calculated as follows:

$$F_o^{m} = \frac{\omega_o^{Frac} S_o^{*}}{\omega_o^{Frac} S_o^{*} + \omega_g^{Frac} S_g + \omega_{sal}^{Frac} S_{sol}} \tag{4.5}$$

$$S_o^{*} = S_o - S_{orm}(S_w) \tag{4.6}$$

$$F_g^{m} = \frac{\omega_g^{Frac} S_g}{\omega_o^{Frac} S_o^{*} + \omega_g^{Frac} S_g + \omega_{sal}^{Frac} S_{sol}} \tag{4.7}$$

$$F_{sol}^{m} = 1 - F_o^{m} - F_g^{m} \tag{4.8}$$

Where p = solvent, gas, oil

$$\omega_p^{Frac} = \frac{\omega_p}{\omega_{p\,max}} \tag{4.9}$$

$(\omega_o\ depends\ on\ pressure\ and\ \omega_{p\,max}\ is\ maximum\ value\ of\ \omega_p)$

ω_{sol}^{Frac} is a function of several gas/oil parameters and is calculated as follows:

$$\omega_{sol}^{Frac} = \left(\frac{\omega_o^{Frac} S_o^*}{\omega_o^{Frac} S_o^* + \omega_g^{Frac} S_g}\right)\omega_o^{Frac} + \left(\frac{\omega_g^{Frac} S_g}{\omega_o^{Frac} S_o^* + \omega_g^{Frac} S_g}\right)\omega_g^{Frac} \tag{4.10}$$

$$F_g^{\mathrm{Im}} = \left(\frac{S_g}{S_g + S_{sol}}\right) \tag{4.11}$$

$$F_{sol}^{\mathrm{Im}} = 1.0 - F_g^{\mathrm{Im}} \tag{4.12}$$

Oil and gas capillary pressure equations is modified as follows:

$$P_{cog}^{eff} = \frac{\omega_o}{\omega_{o\,max}} P_{\mathrm{cog}}(S_g) + \left(1 - \frac{\omega_o}{\omega_{o\,max}}\right) P_{\mathrm{cog}}(S_g + S_{sol}) \tag{4.13}$$

The modified equations for mixture densities, which are based on pure component densities are as follows:

$$\rho_p^{eff} = \omega_p \rho_p^m + (1 - \omega_p)\rho_p^{\mathrm{Im}} \tag{4.14}$$

p = gas, oil, solvent

$$\rho_o^m = \left(\frac{S_o^*}{S_o^* + S_{sol}}\right)\rho_o + \left(\frac{S_{soL}}{S_o^* + S_{sol}}\right)\rho_{sol} \tag{4.15}$$

$$\rho_g^m = \left(\frac{S_g}{S_g + S_{sol}}\right)\rho_g + \left(\frac{S_{soL}}{S_g + S_{sol}}\right)\rho_{sol} \tag{4.16}$$

$$\rho_{sol}^m = \left(\frac{\omega_o S_o^*}{\omega_o S_o^* + \omega_g S_s + \omega_{soL} S_{sol}}\right)\rho_o + \left(\frac{\omega_g S_g}{\omega_o S_o^* + \omega_g S_g + \omega_{sol} S_{sol}}\right)\rho_g + \left(\frac{\omega_{sol} S_{sol}}{\omega_o S_o^* + \omega_g S_g + \omega_{sol} S_{sol}}\right)\rho_{sol} \tag{4.17}$$

$$\omega_{sol} = \left(\frac{\omega_o S_o^*}{\omega_o S_o^* + \omega_g S_g}\right)\omega_o + \left(\frac{\omega_g}{\omega_o S_o^* + \omega_g S_g}\right)\omega_g \tag{4.18}$$

ρ_p^{Im} = pure component densities with $S_o^* = S_o - S_{orm}(S_w)$

The modified equations for mixture viscosities, which are based on ¼ power fluid mixing rule are as follows:

$$\mu_p^{\text{eff}} = \left(\mu_p^m\right)^{\omega_p} x \left(\mu_p^{\text{Im}}\right)^{(1-\omega_p)} \tag{4.19}$$

With p = solvent, oil or gas

$$\mu_o^m = \& \frac{\mu_o \mu_{sol}}{\left(\left(\frac{S_o^*}{S_o^* + S_{sol}}\right)\mu_{sol}^{1/4} + \left(\frac{S_{soL}}{S_o^* + S_{sol}}\right)\mu_o^{1/4}\right)^4} \tag{4.20}$$

$$\mu_g^m = \& \frac{\mu_g \mu_{sol}}{\left(\left(\frac{S_g}{S_g + S_{sol}}\right)\mu_{sol}^{1/4} + \left(\frac{S_{sol}}{S_g + S_{sol}}\right)\mu_g^{1/4}\right)^4} \tag{4.21}$$

$$\mu_{sol}^m \& = \frac{\mu_g \mu_{sol} \mu_o}{\left(\frac{\omega_o S_o^*}{S_n}\right)\mu_{sol}^{1/4}\mu_g^{1/4} + \left(\frac{\omega_g S_g}{S_n}\right)\mu_o^{1/4}\mu_{sol}^{1/4} + \left(\frac{\omega_{sol} S_{sol}}{S_n}\right)\mu_o^{1/4}\mu_g^{1/4}} \tag{4.22}$$

With:

$$\omega_{sol} = \left(\frac{\omega_o S_o^*}{\omega_o S_o^* + \omega_g S_s}\right)\omega_o + \left(\frac{\omega_g S_g}{\omega_o S_o^* + \omega_g S_g}\right)\omega_g \tag{4.23}$$

$$S_n = \omega_o S_o^* + \omega_g S_g + \omega_{sol} S_{sol} \tag{4.24}$$

$$S_o^* = S_o - S_{\text{orm}}\,(S_w) \tag{4.25}$$

μ_p^{Im} = pure component viscosities.

For Mixing Parameter estimation above Minimum Miscibility Pressure (MMP) Computer Modelling Group Recommends using Koval formula, which will represent realistic peak value for ω_o:

$$\omega_o = 1 - 4\log\left(0.78 + 0.22M^{1/4}\right)/\log(M) \tag{4.26}$$

At reservoir conditions: $M = \mu_{oil}/\mu_{sol}$ (4.27)

For the gas mixing parameter, it is recommended to use ω_g equal or greater than oil mixing parameter. Same equation can be used for calculation with $M = \mu_{sol}/\mu_{gas}$.

4.2 Optimized Properties

Several properties were selected to be optimized in the study conducted.

Firstly, the well pattern was selected. This influenced the ratio of production vs injection wells and how they are positioned relative to each other. This parameter has effect on the sweep efficiency of the injected fluid and thus overall recovery factor of the field.

Second parameter to be optimized was well pattern area, which is the area covering all the wells in the pattern. When implemented to the whole field, pattern area influences the distance and overall number of wells used for the field development. These parameters have significant impact on CO_2 breakthrough to the production wells, thus influencing the amount of carbon dioxide stored at the end of simulation period.

Another parameter to be optimized was injection rate. This is a critical parameter for the study, since it not only influences the amount of carbon dioxide sequestrated, but also oil recovery, as the amount of CO_2 affects it sweep efficiency.

Injection into different fluid bearing zones was also considered as injection into oil or water zones can have different effects on both parameters to be co-optimized in this study.

Finally, WAG injection method was analyzed for the purpose of co-optimization. Intermittent water injection can have effect on overall CO_2 amount stored, since water slugs can prevent early breakthrough of the carbon dioxide. These slugs can also influence the sweep efficiency, thus analyzing WAG effect can be critical for CO_2 sequestration and EOR co-optimization.

CHAPTER 5

NUMERICAL MODELING AND SIMULATIONS

5.1 Model construction

CMG IMEX was used to simulate CO_2 sequestration in heavy oil field. Bati Raman field’s properties were used as base for the model. All the publically available information was used for model construction, with some assumptions being made, when no data was available. It should be noted, that the simulations described in this work do not represent actual simulation for Bati Raman or any other specific field, and just used for study of CO_2 sequestration in general heavy oil field.

5.1.1 Bati Raman field

Containing 1.85MMM bbl of original oil in place, Bati Raman field is considered to be the biggest oil field in the Republic of Turkey, which was discovered in 1961(Babadagli et al., 2008).

Dominant producing formation is a very heterogeneous limestone of Cretaceous age with gross thickness of 64m. The size of the field is around 17km long and 2-4 km wide, with structural trap asymmetric anticline. Porosity of the field is indicated as 18% average. Bati Raman is a dual permeability formation, with primary permeability ranging between 10mD and 100mD, and secondary permeability going as high as 2 Darcies, which is indicated by well testing(Babadagli et al., 2008; Sahin et al., 2012).

Bati Raman oil is considered to be extremely heavy and viscous with API gravities ranging from 9° to 15° and viscosity from 450 to 1000cp in some parts of the field. Due to low solution gas-oil ratio the bubble point pressure is also very low (160psi).

Original reservoir pressure and temperatures were 1800psi at 2067ft and 150° F at 1640ft respectively(Sahin et al., 2012).

Primary recovery of the reservoir resulted in just about 1.7% of initial oil in place being produced. As a result EOR methods have been implemented. Between 1971 and 1978 waterflooding was performed in the field. Even though there was a significant increase in recovery factor, it was calculated that overall recovery will be increased to a maximum value of 5% with this technique (Babadagli et al., 2008).

After extensive studies for finding the most efficient method for oil recovery in Bati Ramant field, immiscible CO_2 injection started in 1986 and continued for several decades. Due to very high MMP compared to reservoir pressure, as injection continued, RF was increasing only due to oil swelling, viscosity reduction, gas diffusion into oil, interfacial tension reduction, and overall pressure support to the reservoir. As the result of the full scale CO_2 injection, the production rate of 14000 bbl/d was achieved, with overall 352.8 Bscf of carbon dioxide injected (Sahin et al., 2012).

5.1.1.1 Model geometry and grid

A simple three-dimensional Cartesian model was created using dimensions from Bati Raman as reference. Due to educational license limitation of CMG IMEX, number of total grid blocks in model was limited by 50000. Considering this limitation, the model created has total of 49560 blocks with distribution of 118 x 21 x 20 per X, Y and Z axis respectively. The grid dimensions are as following: 473 ft per grid block in X direction, 469 ft in Y direction, and 21 ft per grid block in Z direction. Overall grid dimensions are 55774 ft x 9843 ft x 420 ft.

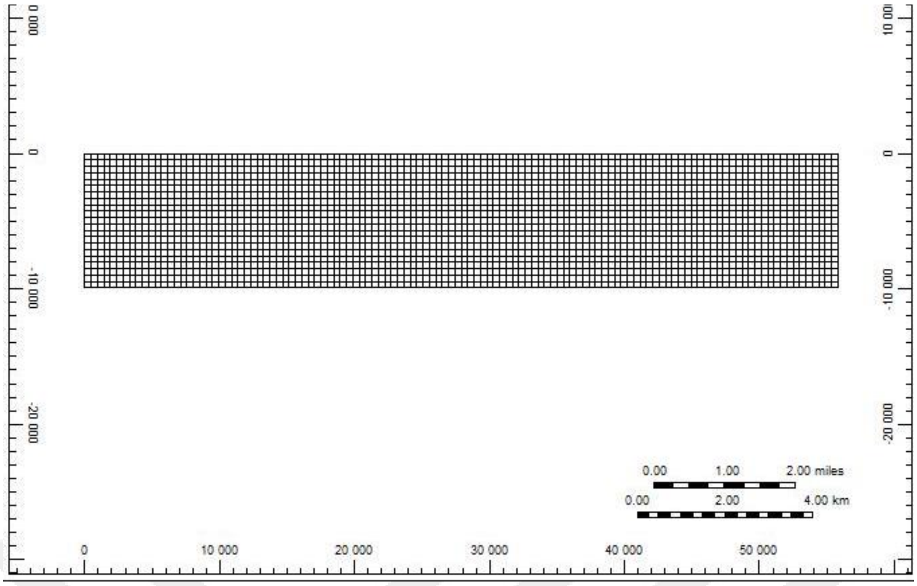


Figure 5.1. X-Y view (top) of the model

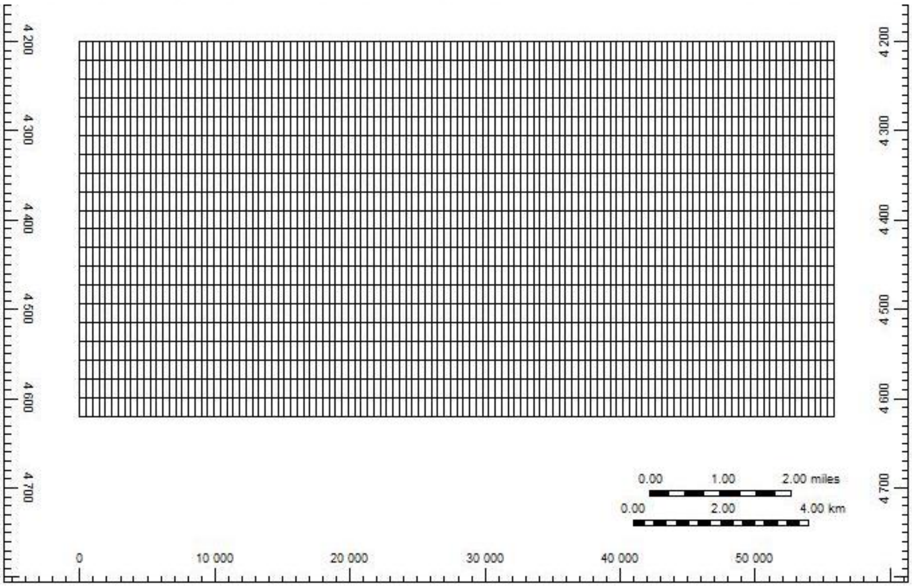


Figure 5.2. X-Z view of the model

5.1.1.2 Reservoir rock and fluid properties

Reservoir rock properties used for the simulation are shown in the Table 5.1:

Table 5.1 Reservoir rock properties

Parameter	Value
Porosity (%)	18
Matrix Permeability in X direction (mD)	60
Matrix Permeability in Y direction (mD)	60
Matrix Permeability in Z direction (mD)	6
Net Pay Thickness per grid block (ft)	16.5
Bubble point pressure (psi)	174.7
Oil Saturation (%)	79
Initial Pressure (psi)	1864.7
Water Saturation (%)	21
Rock Compressibility (1/psi)	0.00000381
Temperature (F)	160

By using Bati Raman oil density of 61.4963 lb/ft3 solubility, viscosities, relative permeability, and capillary pressures were generated using correlations by CMG IMEX and are represented in the Figures 5.3, 5.4, 5.5 and 5.6:

Enhanced-Oil-Recovery, the revenue should be high enough for the company to profit from the process. Firstly, stable high oil prices, will influence company's aim to recover as much oil as possible during high oil price period, which will result in higher demand for CO2-EOR. Furthermore, as it can be seen from equation above, introducing subsidies for CO2 sequestration will increase company's profit, which is one of the government's method to motivate operator company. To make the process even more profitable, carbon dioxide recycling should be taking into account. As it can be seen from the simulations conducted above, after CO2 breakthrough significant amount of it is being produced together with oil, which may be postponed by optimizign pattern area or implementing WAG. In addition, recycled carbon dioxide can be re-injected into the reservoir, thus reducing the required amount of CO2 to be purchased. Finally, increasing taxes to the produced CO2 during industrial processes, and development in carbon capture technologies, which in terms makes the process cheaper, will reduce the price of CO2 to be purchase for sequestration. Moreover, significant increase in tax, may reduce carbon dioxide price to negative, which may be considered as a subsidy for carbon sequestration (Veld et al., 2013).

Considering all of the discussed above, results of the simulations indicate, that for the case of both oil and CO_2 purchase price being high, co-optimization shift more to the EOR side, meaning that it will be more profitable for the company to implement strategies resulting in higher oil RF, e.g using inverted 9 spot pattern, while minimizing pattern area. Furhermore, considering high purchase cost of carbon dioxide, injected amount should be minimized, based on the profit.

For the case of oil price being low, and either subsidies for CO_2 injection or negative CO_2 purchase price, co-optimization will shift to the carbon storage project side. So, it would be beneficial to increase amount of carbon dioxide stored, by implementing 5 spot injection, while maximizing overall injection rate, using maximum possible pattern area, which will be limited by number of wells and injection pressure per single well, and injection into the oil zone.

Finally, for the case of high oil price and subsidies for CO_2 injection, inverted 5 spot, with maximum possible injection rate, injecting into the oil zone will be most beneficial in terms of profit.

It should be noted, that in all three cases, implementation of WAG injection is beneficial and will increase the overall profit.

CHAPTER 7

CONCLUSION

CO_2 is one of the major greenhouse gases contributing to the global warming and climate change. Apart from reduction in greenhouse gases emissions, one of the main methods for climate change mitigation is carbon capture, utilization and storage, which include carbon dioxide sequestration in hydrocarbon reservoirs. However, noting that most of the oil reservoirs are still producing, and CO_2-EOR proves to be efficient in many oil reservoirs, the most optimum way for carbon storage is to co-optimize both CO_2 sequestration and oil recovery processes. Taking into account efficiency of immiscible CO_2-EOR in Bati Raman heavy oil field, the study has been conducted for optimization of sequestration in immiscible heavy oil environment.

The study included sets of numerical simulations to evaluate effect of change in different injection strategies on oil recovery factor and amount of carbon dioxide stored in the reservoir. The parameters that were evaluated are injection patterns; patterns' area; carbon dioxide injection rates; CO_2 injection into oil zone, water zone, and both oil and water zones; and finally efficiancy of water-alternating-gas injection compared to conventional carbon dioxide injection. The model was constructed using CMG's Builder and simulations were conducted using CMG's IMEX softwares.

First scenario simulations investigated effects of different injection patterns. Results indicate that while inverted 9 spot and 5 spot patterns are the most efficient in terms of oil recovery factor and carbon dioxide deposition respectively, the optimum ones are to be considered inverted 5 spot and inverted 7 spot patterns. Furthermore, since inverted 5 spot is simpler and requires less wells to be drilled, it is superior in comparioson to inverted 7 spot.

For the second scenario pattern size was evaluated to uderstand how increase or decrease in pattern area influences oil recovery and carbon dioxide sequestration for whole field development. Results indicate that, while with decrease of pattern area oil RF increases, CO_2 sequestration on contrary decreases. In addition, well spacing affects carbon dioxide breakthrough to the production wells, which should also be taken into account while designing field development. Furthermore, simulations indicate, that number of wells affect the results at least as strongly as well spacing. Identification of efficient pattern area should be considered on field to field basis considering financial and time aspects as well.

Third scenario evaluated effect of carbon dioxide injection rates. Results indicate, that increase in injection rates results in higher recovery factors and carbon dioxide deposited. However, as the injection rate increases, rate of increase in oil RF decreases. Furthermore, for field development, it should be noted, that higher injection rate results in earlier carbon dioxide breakthrough, which in terms results in decrease of carbon sequestrated.

Fourth scenario simulations were aimed to identify reservoir zone most suitable for oil recovery and carbon dioxide deposition. In terms of oil recovery factor, injection zone does not really affect the results, with differences being negligible. As for CO_2 deposition, it is most efficient to inject just into the oil zone, however, the injection should be stopped at earlier time. Injection into water or both zones show similar and more stable results, and are better for injection for longer periods.

Fifth scenario simulations evaluated feasibility of water-alternating-gas injection for co-optimization purposes. Results indicate, that implementing WAG results in up to 38% increase in oil recovery factor while injecting water for 2 times longer period than carbon dioxide. As for carbon sequestration, simulations indicate, that injection of water in small amounts significantly reduces mobility of carbon dioxide, and thus prevent its early breakthrough and show more stable CO_2 deposition. Same as recovery factor, injecting water for 2 times longer period than carbon dioxide show higher results in terms of carbon sequestrated as well.

Overall, while some of the parameters, such as inverted 5-spot pattern, and WAG implementation, are more obvious to be used for the purpose of co-optimization, others need to be chosen on field to field basis. Pattern size, injection rate, and injection zone, are dependent on how long the CO_2 injection and oil recovery are planned to continue, as these parameters affect time for CO_2 breakthrough, and thus both oil production rate and amount of carbon dioxide stored. Furthermore, the parameters need to be optimized with regards to oil and CO_2 markets, since the operations discussed in this study need to provide profit to the operator company, and thus need to be considered at the time of implementation.

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