Simulation of CO_2 Injection in Gas Reservoir Using ECLIPSE

by

Sarah Adiba Binti Mohammed Yussof

Dissertation submitted in partial fulfilment of
the requirements for the
Bachelor of Engineering (Hons)
(Petroleum Engineering)

MAY 2013

Universiti Teknologi PETRONAS
Bandar Seri Iskandar
31750 Tronoh
Perak Darul Ridzuan

CERTIFICATION OF APPROVAL

Simulation of CO_2 Injection in Gas Reservoir Using ECLIPSE

by

Sarah Adiba Binti Mohammed Yussof

A project dissertation submitted to the
Petroleum Engineering Programme
Universiti Teknologi PETRONAS
In partial fulfillment of the requirement for the
BACHELOR OF ENGINEERING (Hons)
(PETROLEUM ENGINEERING)

Approved by,

____

(AP Dr. Muhannad Talib Shuker)

UNIVERSITI TEKNOLOGI PETRONAS

TRONOH, PERAK

May 2013

CERTIFICATION OF ORIGINALITY

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

SARAH ADIBA BINTI MOHAMMED YUSSOF

ABSTRACT

This paper examines on the recovery factor of natural gas production by injecting CO_2 into a natural gas reservoir. This task will be performed by using reservoir simulation software (Eclipse). This injection interacts with CH_4 to create conditions favorable for gas recovery. The main target of this project is to investigate the optimum injection rate to get the optimum recovery of methane production. In addition, carbon sequestration study with enhanced gas reservoirs is also investigated in this study. A study of carbon sequestration is focused on the variation of reservoir pressure to get the optimum amount of gas stored in the reservoir.

ACKNOWLEDGEMENT

The completion of this project would be impossible without the great support of many people. I would like to take this opportunity to express my appreciation to everyone that has involved in my project directly or indirectly.

First and foremost, I would like to express my deepest gratitude to AP Dr Muhannad Talib, my final year project supervisor, for the unlimited support, patient guidance, enthusiastic encouragement and useful critiques of this project. Furthermore, I would like to thank Mr Babak Moradi and Muhammad Ali Buriro for their advice and assistance throughout my project. I would also like to extend my thanks to my final year project 1 coordinator, Dr Fitri and my final year project 2 coordinator, Mr Aslam for keeping my project progress on schedule. I would like to express my appreciation to University Technology of Petronas for given me a great opportunity to conduct my final year project and complete my undergraduate study as well with the best educational opportunity. I would like to offer my special thanks to Schlumberger for the reservoir simulator, ECLIPSE and make my final year project possible. Finally, I wish to thank my parents, my family and my friends for their endless support, beautiful love and encouragement throughout my study.

TABLE OF CONTENTS

LIST OF FIGURES

LIST OF TABLES

CHAPTER 1

INTRODUCTION

1.1 Background

Comparable to crude oil production the production of natural gas is divided into a number of stages. At a first stage, production hydrocarbons flow to the production wells naturally and ascent to the surface along the well due to usually high reservoir pressures. However, pressure in the reservoir decreases gradually. Therefore, a prolongation of production may be accomplished by Enhanced Gas Recovery method. The reservoir yield is usually higher as compared to that of oil for gas production. The potential to recover a depleted gas reservoir is approximately an average of 75 per cent of the gas from the reservoir rock as a result of the natural formation pressures (up to 50% at a maximum from natural oil deposits). This is due to flow of natural gas through rock is better than that of the rather viscous crude oil.

The installation of compressors may be a first measure to reduce the counter pressure for the ascending gas. The yield of a natural gas reservoir may further be increased by Enhanced Gas Recovery (EGR) methods, e.g. by injecting carbon dioxide (CO_2) into the reservoir rocks to rise the pressure in the reservoir (Fig. 1). Based on figure 1, it has shown the principle sketch of the technology to enhance the production of natural gas (yellow) by means of CO_2 (blue). CO_2 increases the pressure in the reservoir rock was which reduced by decades of gas production.

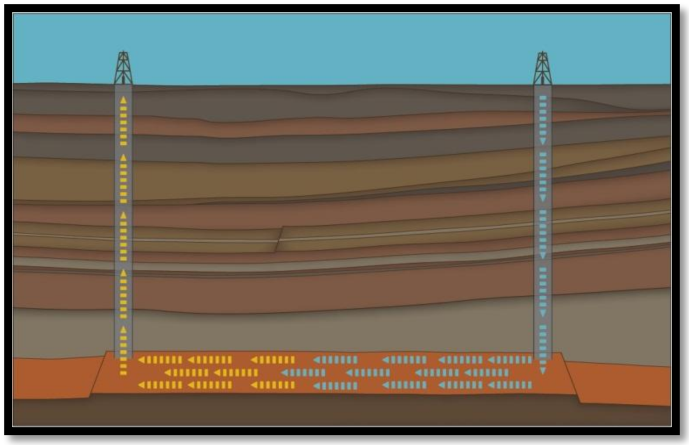

FIGURE 1: Principle sketch of the technology to enhance the production of natural gas (yellow) by means of CO_2 (blue). (Source: Retrieved from http://www.clean-altmark.org/front_content.php?idcat=1486&client=36&lang=40)

In a simplest word, EGR in a gas reservoir, a gas is injected to displace the natural gas in the depleted gas reservoir by a gas of less commercial value and abundantly available such as CO_2.

In the reference of scenario of the International Agency (IEA 2008), there is possibility of emissions of CO_2 to grow from 28 Gigatonnes in 2006 to 42 Gigatonnes in 2030 (Figure 2). Assumed that there is no change in governmental policies, this would lead to a concentration of 1000ppm in the atmosphere and forecasted increase in temperatures by 6^0C by the end of this century.

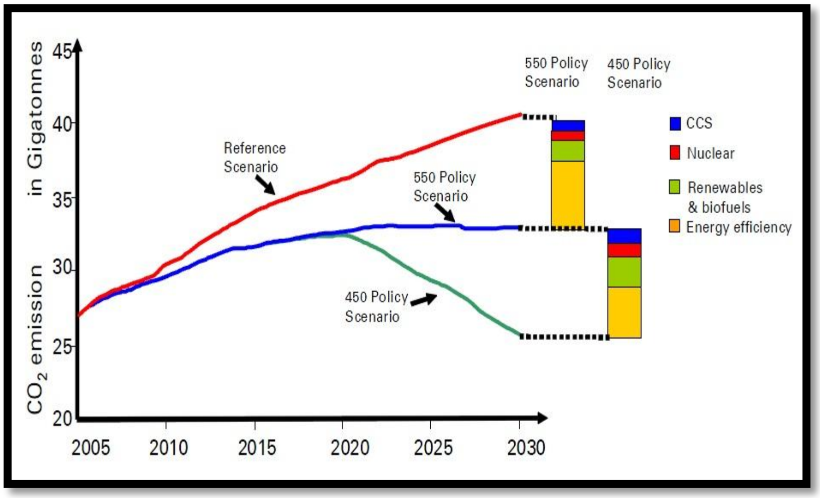

FIGURE 2 : Energy related CO_2 emissions for different scenario. (Source: Clemens et al, 2010)

One of the ways to reduce greenhouse gas emission is Carbon Capture and Sequestration (CCS). The idea behind this is injecting direct CO_2 into depleted natural gas reservoirs for carbon sequestration with enhanced gas recovery. The International Energy Agency (IEA) has estimated that as much as 140 GtC could be sequestered in depleted natural gas reservoirs worldwide

1.1.1 CO_2 Storage

The main geological conditions required for CO_2 storage are:

a) Reservoir Rock

Both porous (having pore spaces in which carbon dioxide can reside) and permeable (having links between pore spaces allowing the carbon dioxide to permeate through the rock).

b) Trapping Mechanism

The purpose of this is to stop the carbon dioxide migrating outside the target geological feature. There are four basic mechanisms hold the CO_2 in place: stratigraphic /structural, residual, solubility, and mineral trapping.

c) An impermeable caprock

To halt the carbon dioxide migrating upwards

Depleted oil and natural gas fields, which generally have proven geologic traps, reservoirs and seals are potentially excellent sites for storing injected carbon dioxide.

The stages in storing carbon dioxide are:

i. Selecting the storage site.
ii. Preparing the site and CO_2 for injection
iii. Injecting the CO_2
iv. Monitoring the CO_2
v. Long term future of CO_2 after injection.

1.1.2 CO_2 injection

Source (Gaspar et al., 2005) claims that aquifer beyond the depth of 800 m makes CO_2 to act as a supercritical fluid and it would have density as high as that for water. CO_2 density in aquifers with depth of greater than 3650 is higher compare to that of sweat water. In addition to the aquifer, the location and depth completion of the injection wells might have sufficient permeability and porosity to resist keeping the injected CO_2 in the aquifer.

Once on site, CO_2 may need to have residue removed using suction scrubbers. After that, it is compressed to supercritical state in order to be stored. The injectivity of the reservoir is determined at the time of site characterization. Moving on the process, the CO_2 is later pumped into the reservoir at a pressure greater that the reservoir fluid pressure. The pressure must be sufficient to enable the CO_2 to enter the formation, but not so great as to fracture the formation.

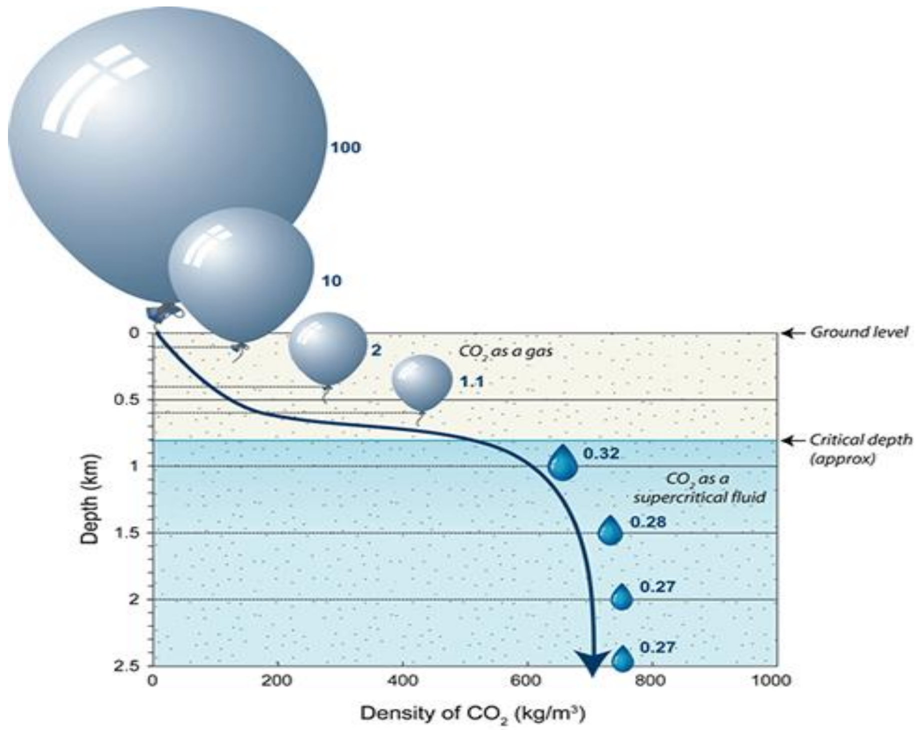

FIGURE 3: The density of CO_2 versus Depth. (Source: http://www.co2crc.com.au/aboutccs/storage retrieved on 12th July 2013)

CO_2 will be injected at depths below 0.8 km (2600 feet) as CO_2 increases in density with depth and becomes a supercritical fluid below 0.8 km. The reason is because supercritical fluids take up much less space, as shown in this figure 3, and diffuse better than either gases or ordinary liquids through the tiny pore spaces in storage rocks. The blue numbers in this figure has shown the volume of CO_2 at each depth compared to a volume of 100 at the surface.

1.1.3 Benefits of CO_2 injection

The Methane (CH_4)-CO_2 systems have a number of interesting characteristics which make the case for enhanced gas recovery favourable. Clemens, Secklehner, Mantatzis, and Jacobs (2010) have summarized these features as follows:

1) It provides economic benefits to operators
2) It accelerates gas production and increase the ultimate recovery
3) CO_2 maintains the reservoir pressure and ultimately enhance gas production.
4) The density of CO_2 is 2 to 6 times higher than that of CH_4 at reservoir conditions. Therefore, gravity stabilized displacement can be achievedA relatively stable displacement process can be achieved due to the lower mobility ratio of CO_2 (more viscous) relative to CH_4 .
5) A high injectivity of the supercritical CO_2 is allowed due to the nearly gas-like viscosity of the supercritical CO_2.
6) Higher CO_2 solubility in formation water compared to that of CH_4 will delay CO_2 breakthrough. . Higher CO_2 solubility in formation water compared to that of CH_4 will postpone the CO_2 breakthrough
7) Lower mobility ratio of CO_2 (more viscous) relative to CH_4 will have a relatively stable displacement process.

1.2 Problem Statement

It is revealed in literature that CO_2 injection can improve gas recovery for a depleted gas reservoir. However, a study needs to be conducted to know the amount of gas that can be recovered by using carbon dioxide injection. Plus, literature also shows that there is a vast potential for carbon sequestration in depleted gas reservoirs but there is not many carbon sequestration with enhanced gas reservoirs have not been tested on the field.

1.3 Objective and Scope of Study

1.3.1 Objective

This work attempts to improve ultimate gas recovery by injecting CO_2. Thus, this study embarks on the following objectives:

1) To perform sensitivity analysis study to find optimum injection parameters such as flow rate and injection pressure.

2) To determine amount of carbon dioxide storage.

1.3.1 Scope of Study

The scope of study focuses on the recovery of a depleted gas reservoir. In this study, the Schlumberger ECLIPSE was the main instrument to perform the reservoir simulation software. This study focuses on different parameters and the effect to the total gas production. For this project, different values of injection rates are selected to be evaluated. The effect will then be discussed on the results and discussion section. The lowest values of 174 bar will be set as the base for the reservoir simulation. Not only that, a simulation for carbon sequestration is conducted. For the carbon sequestration, a few reservoir pressures are tested. A study on the effect to the CO_2 storage is evaluated.

CHAPTER 2
LITERATURE REVIEW

2.1 Enhanced Gas Recovery (EGR)

As stated by Alhashami, Ren and Tohidi (2005), injection of CO_2 into oil reservoir for enhanced oil recovery is broadly investigated in contrary with CO_2 injection for enhanced gas recovery. As Clemens, Secklehner, Mantatzis and Jacobs (2010) have demonstrated on their project, there are some challenges that needed to face when it comes to enhanced gas recovery. As Clemens, Secklehner, Mantatzis and Jacobs (2010) also stated that CO_2-EOR has been successfully to recover incremental oil after water flooding. In the USA, there is more than 260,000 bbl/d are produced using this method. However, only small scale projects of CO_2 enhanced Gas Recovery (CO_2-EGR) have been performed until now despite this method has been proposed. Furthermore, in their study, the example cases of CO_2-EGR show that even for almost ideal reservoir structures (elongated with wells at one end and injection at the other end), limited potential CO_2-EGR exists. To increase gas production compared with depletion, a good well placement and knowledge of the structure accordingly is required, the production facilities have to be able to handle high CO_2 contents and CO_2 injection should commence later in the lifetime of the field to prevent trapping of hydrocarbon gas in unsweep areas at high pressures.

Enhanced Gas Recovery (EGR) by CO_2 flooding is a challenge because of high carbon capture and storage costs (Oldenburg et al., 2001). However, revenue from incremental gas recovery can decrease the incremental costs (Oldenburg et al., 2001). Experimental and simulation studies have looked at repressurization by using supercritical CO_2 to depleted gas reservoirs and enhance recovery.

A few studies are highlighted below. Mamora and Seo conducted experiments on the extent of CH_4 gas recoverable by injecting CO_2 (Mamora and Seo, 2002). The experiments showed recovery of 73% to 85% of the original gas-in-place (OGIP) which is higher than the primary recovery of 65% of OGIP. Moreover, the experiment found that the dispersion of supercritical CO_2 in CH_4 is low which is about 0.01 to 0.12 cm^2/min. It is found that injecting CO_2 can improve recovery of natural gas. However, the experiment was restricted only on one-dimensional displacement and the performance of a carbonate core. Therefore the results from the experiments may differ for a multidimensional reservoir with sandstone formation. Oldenburg and his co-workers (Oldenburg et al., 2001, Oldenburg and Benson, 2001, Oldenburg and Benson, 2002, Oldenburg, 2003, Oldenburg et al., 2004) simulated the effects of EGR by CO_2 flooding.

2.2 CO_2 Injection

McPherson Lee, and Romero (2004) has conducted a project which has a primary purpose of this project was to evaluate the possible effects during and after injection of CO_2 in a reservoir. Results from experimental analyses served to parameterize state-of-the-art coupled reactive flow and deformation or strain numerical model simulations. Interpretations of simulation results provide a foundation for gas-reservoir pilot injection test design. Specifically, model results demonstrate that injected CO_2 plume migration rates are influenced significantly by concomitant mineralization and associated porosity/permeability evolution. Additionally, simulations demonstrate that overpressures induced by high CO_2 injection rates can cause significant rock strain that may severely reduce injectivity and seal integrity. These results and conclusions are being used to develop designs and provide engineering constraints for a pilot CO_2 injection test in a natural gas reservoir.

Both industry and the federal government are interested in determining the viability, risks, and optimal sites for sequestering CO_2 in the subsurface. Depleted gas reservoirs are especially appealing sites because they are otherwise relatively useless, and the value-added opportunity for enhanced gas recovery makes it economically attractive. A primary objective of this project was to evaluate the possible effects during and after injection of CO_2 in a reservoir.

Figure 4 has shown a systematic diagram of a single power plant and gas reservoir, Carbon Sequestration with enhanced gas recovery (CSEGR) is the injection of CO_2 into depleted natural gas reservoirs for carbon sequestration with enhanced gas recovery as demonstrated by Oldenberg, and Benson (2002).Due to the large quantities of natural gas held over geologic time scales, depleted gas reservoirs offer a proven integrity against gas escape and large available capacity for carbon sequestration. It is estimated at 140 GtC (Gigatonnes Carbon) worldwide (based on IEA Greenhouse Gas R&D Programme, 1997), and 10-25 GtC in the United States (based on U.S. Department of Energy, DOE/SC/FE-1 (1999)). Furthermore, there is no technical barriers present to CO_2 injection, although there are certainly costs associated with the injection of a highly corrosive gas such as CO_2 (Energy Conver. Mgmt, 38 Supply. (1997)).

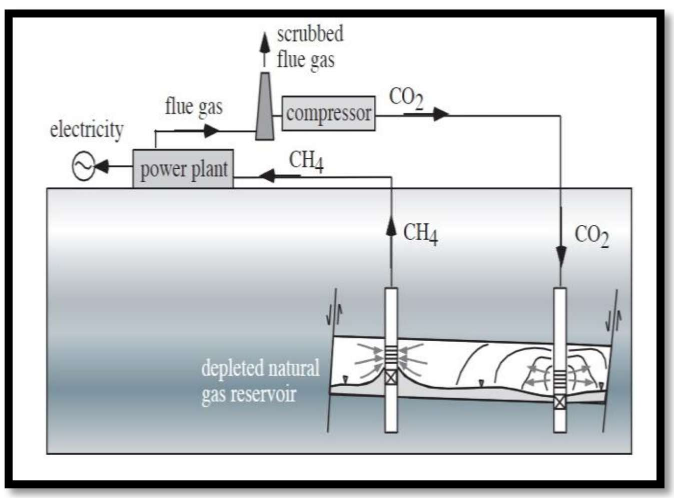

FIGURE 4 : Schematic of a coupled CSEGR system for a gas-fired power plant

(Source : Oldenberg, and Benson, 2002.)

The major challenge to injection operations would ne the initial low reservoir pressure in the depleted gas field. As illustrated in figure 5, the well(s) might have to be choked back via surface choke if a maximum injection rate constraint is defined. This is to obtain a wellhead pressure low enough to respect that constraint. However, this low wellhead pressure will force the wellhead flowing conditions towards CO_2 vaporizations.

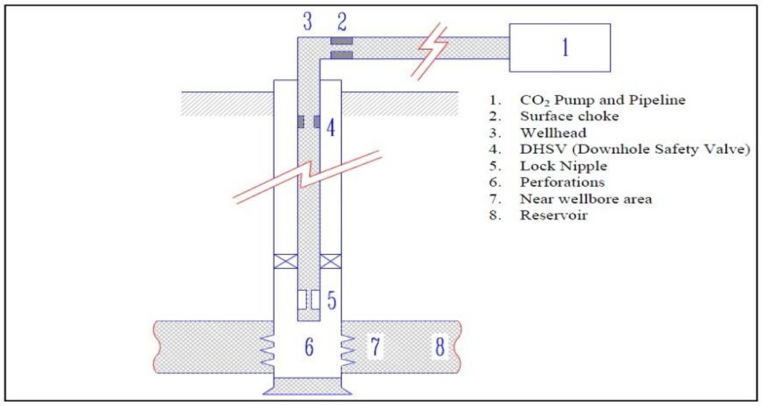

FIGURE 5: CO_2 injection systems (Source : Galic et al, 2009.)

Moreover, two main reasons that CO_2 EGR has never been tested in field are CO_2 is still an expensive commodity and geological carbon storage is not widely practiced as well as the concern of CO_2 injection may excessively mix with primary natural gas.

CO_2 injection and storage into a gas reservoir will be attractive in situation where the process can provide benefits to operators economically. Injection of CO_2 into gas reservoirs can accelerate gas production and increase in ultimate recovery which is the main objective of this project.

Galic, Cawley, Bishop, Todman and Gas (2009) have modeled CO_2 supply would come from burning fossil fuels at a power plan which produces CO_2 to be captured, dehydrated, compressed and transported to an onshore pumping facility. This is approximately at 70-80 bar and at ambient temperature (0-20^{o}C). Furthermore, their study demonstrated that the complete injection system should be designed, monitored and controlled to :

1) Keep the CO_2 under stable dense/ liquid phase and avoid any phase changes in the injection system.

2) Maximize the CO_2 storage potential of the reservoir and also

3) Ensure that the CO_2 will be kept safely contained within the reservoir for the long-term by understanding and monitoring the impact of stress variations and chemical interactions between the CO_2 and the reservoir on its integrity.

However, CO_2 has to be injected at a high velocity to overcome hydrodynamic dispersion and excessive gas mixing will be avoided. Oldenburg then extended his model to a three dimensional displacement model to optimize the amount of CO_2 injected into the reservoir (Oldenburg and Benson, 2002). It is concluded that permeability heterogeneity causes early CO_2 breakthrough. Hence, he suggested placing injection wells far away from the production well. This is to take advantage of fast repressurisation effects in advance of excessive molecular diffusion of CO_2 and existing gas occurs. Not only that, after EGR, the CO_2 storage site is created by shutting in the production well as CO_2 injection continues. Oldenburg et al. mainly focused on CO_2 injection in a depleted gas reservoir although not all gas reservoirs is depleted. This raises the issue of when should EGR be carried out to optimize profitability. Clemens and Wit has conducted a study on EGR by CO_2 flooding at different production maturities (Clemens and Wit, 2002). The study has shown incremental gas production of -4.2% to +9.4% compared to that of conventional recovery. It suggests that, from an engineering standpoint, injecting CO_2 at the beginning of a field life has adverse effects and gain the most incremental recovery. Finally, it is noted that the development of a field will depend on economic factors.

2.3 **Carbon Sequestration**

Furthermore, depleted natural gas fields are targets for carbon sequestration by direct CO_2 injection. CO_2 storage occurred by injecting supercritical CO_2 into a geological formation which can trap it permanently. Storing and injecting CO_2 in the supercritical form permits a larger storage volume (Clemens and Wit, 2002, Oldenburg and Benson, 2002, Al-Abri and Amin, 2009, Benson, 2004). This is due to the concentration supercritical CO_2 is higher than gaseous CO_2 (Mamora and Seo, 2002). Therefore, for the same amount of fluid, CO_2 is stored in the supercritical form is more than in the gaseous form. Supercritical CO_2 is suitable as it behaves like liquid and gas as it has viscosity of gas and density close to that of a liquid. Supercritical condition occurred at above its critical pressure (7.38MPa) and temperature (31^{o}C), CO_2 at any pressure and temperature that. In order to maintain CO_2 in the supercritical form (CO2CRC, 2010b, Orr, 2004), the hydrostatic pressure at subsurface depths of 800m and beyond are assumed to be sufficient.

The main geological conditions required for CO_2 storage are reservoir rock, trapping mechanism and an impermeable cap rock. Furthermore, CO_2 is assumed to be trapped physically and chemically. Depleted oil and natural gas fields, which generally have proven geologic traps, reservoirs and seals are potentially excellent sites for storing injected carbon dioxide.

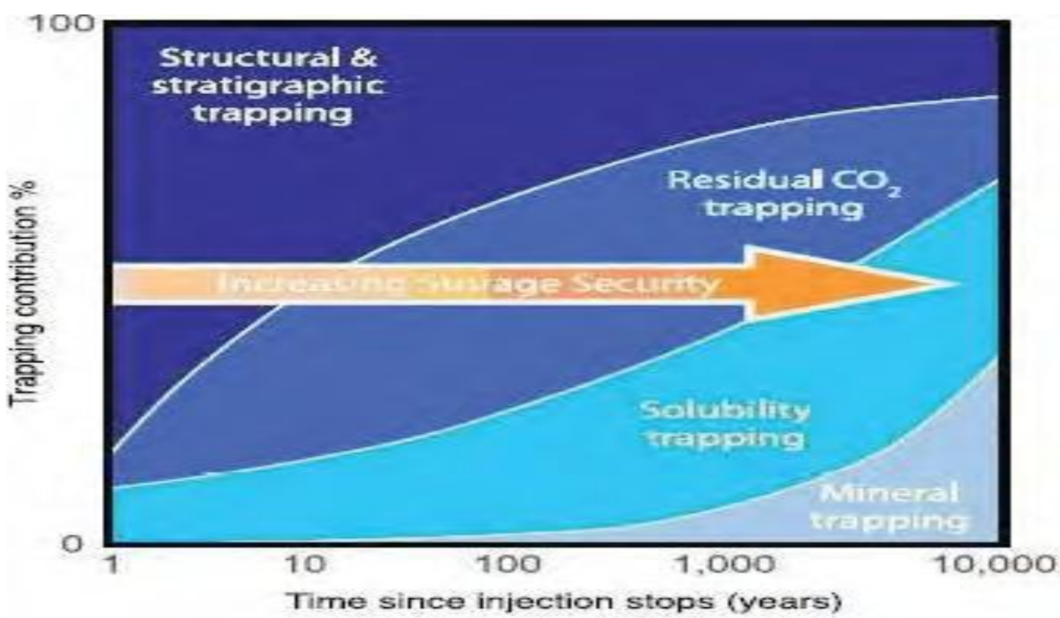

FIGURE 6 : CO_2 trapping mechanism timeline (Retrieved at http://www.ccsassociation.org/.)

Figure 6 shows different trapping mechanisms as a function of time (CCSA, 2009). Structural and stratigraphic traps are the main types of entrapment in the early stage of CO_2 storage (CCSA, 2009). Mineral trapping is the safest form of CO_2 trapping. This is because it is immobile due to the solidification of CO_2 solidifies (CCSA, 2009). Although target gas reservoirs for carbon sequestration are depleted in methane (CH_4) with pressures as low as 20–50 bars, methane is still present. This is because of the ability of such reservoirs to fill gas during production and their proven integrity to trap the gas against future escape (Oldenburg et al., 2001). Studies have suggested that additional methane can be recovered from depleted natural gas reservoirs by injecting CO_2 (van der Burgt et al., 1992; Blok et al., 1997; Oldenburg et al., 2001). The idea is to inject CO_2 at some distance from producing wells and restore the reservoir pressure to produce additional $CH_{4.}$

2. 4 Expected Reservoir Processes

With sufficient permeability, the CO_2 injection will flow in the reservoir by pressure gradient and gravitational effects. The presence of liquid form of CO_2 near the wellbore will flow strongly downward through the gas reservoir due to the abundance of CO_2 density. As CO_2 is denser than CH_4 at all relevant pressures (see figure 7) and will undergo gravity displacement and displace the CH_4 in the gas reservoir as well as repressurizing the reservoir.

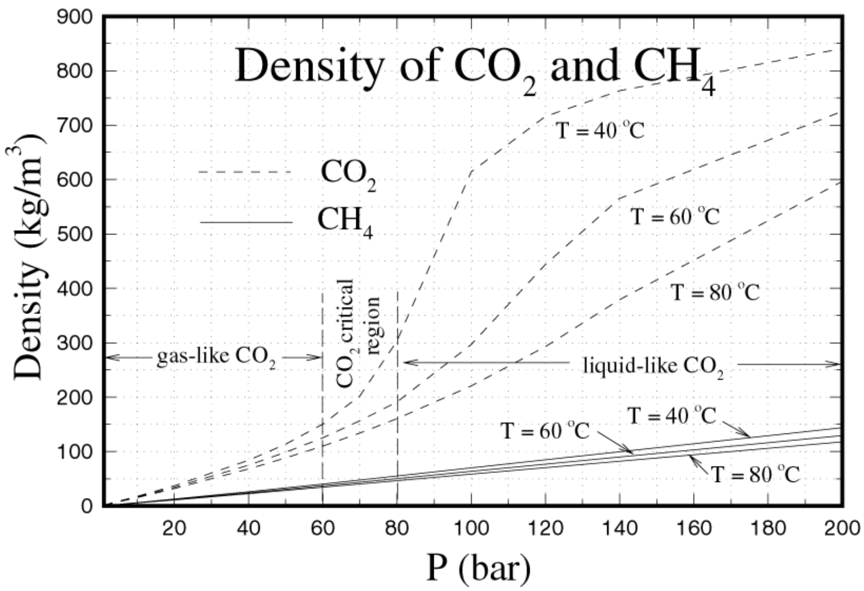

FIGURE 7: Density of CO_2 and CH_4 as a function of pressure for various temperatures based on data from Vargaftik et al. (1996).

CO_2 injection can deflect the water table, which rises to repressurization at a large distance from the injection well. Furthermore, the tendency for CO_2 to flow downwards due to density effects can be exploited in CSEGR by injecting CO_2 at the bottom layer of the reservoir and producing CH_4 at higher levels as is done to minimize water coning. In the simulation, the injection and production wells will be independently controlled and monitored to evaluate the optimum recovery for the depleted gas reservoir. Simulation of injection of CO_2 into a depleted natural gas reservoir is conducted.

2.5 Eclipse

It has been recognized that an efficient way of understanding and possibly resolving these problems arise on this study is by using a reservoir simulation which is ECLIPSE. Reservoir simulation is a combination of physics, mathematics, reservoir engineering and computer programming. It is to develop a tool to predict reservoir performance under various operating conditions. Furthermore, accurate performance predictions for any hydrocarbon/gas hydrate reservoir under different operating conditions need to be obtained as studied by Phale, Zhu, White and and McGrail (2006). The Eclipse-300 compositional reservoir simulation program was used to build a reservoir model for history-matching and forecasting production performance under several reservoir depletion scenarios. Vogel (2009) has stated that The ECLIPSE E300 is a numerical simulator written in FORTRAN77 which uses a finite differences (FD) method to discretize and solve multiphase multicomponent flow equations. Vogel (2009) also stated that the ECLIPSE E300 is able to use three calculation methods for the next time step: fully implicit, adaptive implicit and IMPES. Grids for ECLIPSE E300 can be 3-dimensional with Cartesian or radial coordinates. Sections can be refined via local grid refinement to focus on a relevant area.

CHAPTER 3

METHODOLOGY

3. 1 Research Methodology

For the study of EGR, the base case for the gas reservoir is set to be deeper than 2,500 ft. Shown in figure 8 is the phase diagram for CO_2 indicating that supercritical conditions will prevail in typical gas reservoirs

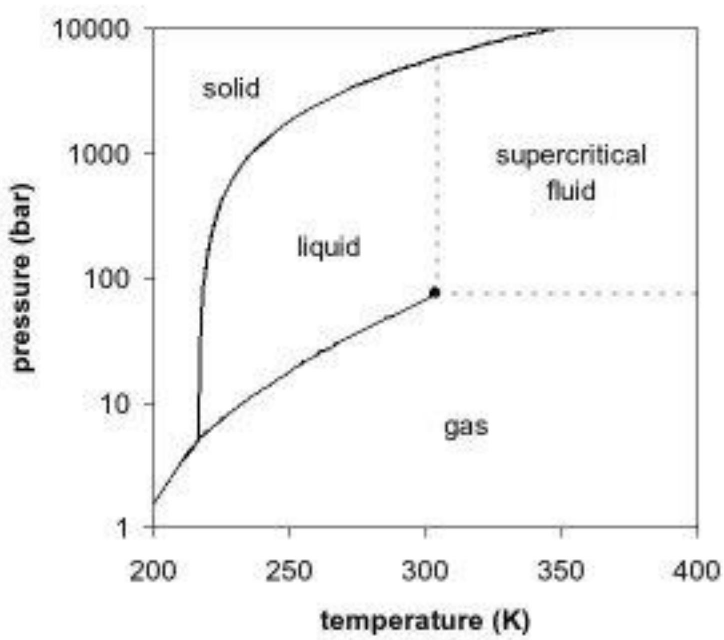

FIGURE 8: Phase diagram of CO_2 (Source : Retrieved from http://cnx.org/content/m32935/latest/#id4571604)

A base case is set with a pressure of 174 bar and 363.15 K (90^{o}C) for the reservoir simulation. This is to ensure that the CO_2 injected is in supercritical condition.

The methodology that is being used to evaluate and accomplish the project can be summarized based on the following phase as per shown in the figure below. :

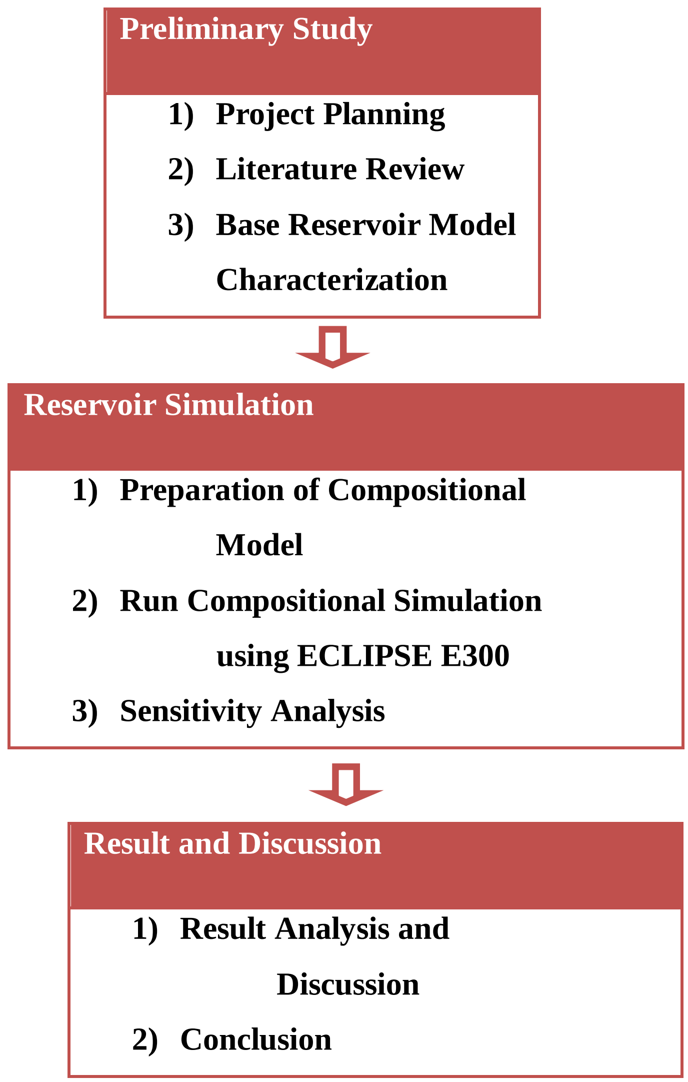

FIGURE 9: Research Methodology Flowchart

3.2 Reservoir Simulation

ECLIPSE 300 was used as a tool to simulate the Compositional Model. In this study, CO_2 was injected to enhance the gas recovery into 3D homogeneous model. Then, from the base model, the base case model was adjusted to see the response of the simulators when there were the effect of CO_2 injection rates and the effect of reservoir pressure to the CO_2 storage.

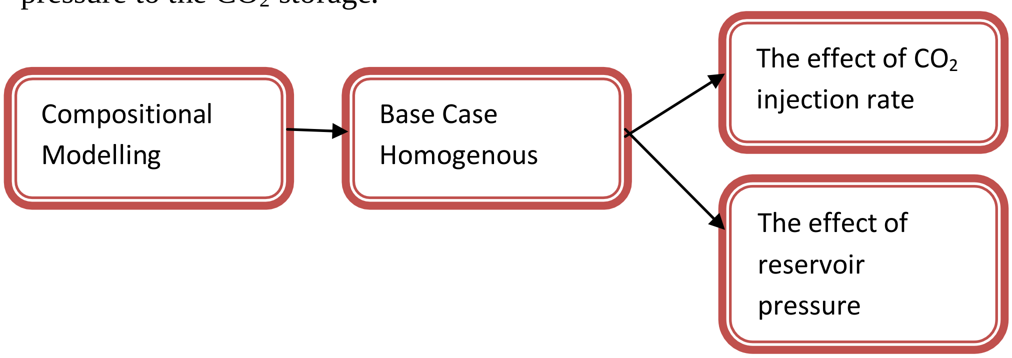

FIGURE 10 : Simulation Work Flow

1) Effect of CO_2 Injection Rate

Case	CO_2 Injection (Mscf/Day)
Base Case	2000
Scenario 1	4000
Scenario 2	6000

TABLE 1 : CO_2 Injection Rate

2) Effect of Reservoir Pressure

Case	Reservoir Pressure (Bar)
Base Case	174
Scenario 1	180
Scenario 2	186

TABLE 2 : Reservoir Pressure

3.3 Project Activities

The project activities were highly dependent to the literature review as well as the involvement to the reservoir simulation. Society of Petroleum Engineer (SPE) papers, journals, online papers and master thesis are the main sources for the project development. Schlumberger ECLIPSE was the main tool for this project.

The activities taken in each phase of the research methodology are explained in the following table 3.

No.	Activities
1	Literature Review
2	Simulation Study
3	Preparation of Compositional Model
4	Conduct or running the simulations
5	Analysis the data
6	Develop a criteria for CO_2 injection process in natural gas reservoir
7	Analysis
8	Review
9	Conclusion
10	Writing a Research Paper
11	Completion

TABLE 3: Project Activities

3.4 Gantt Chart

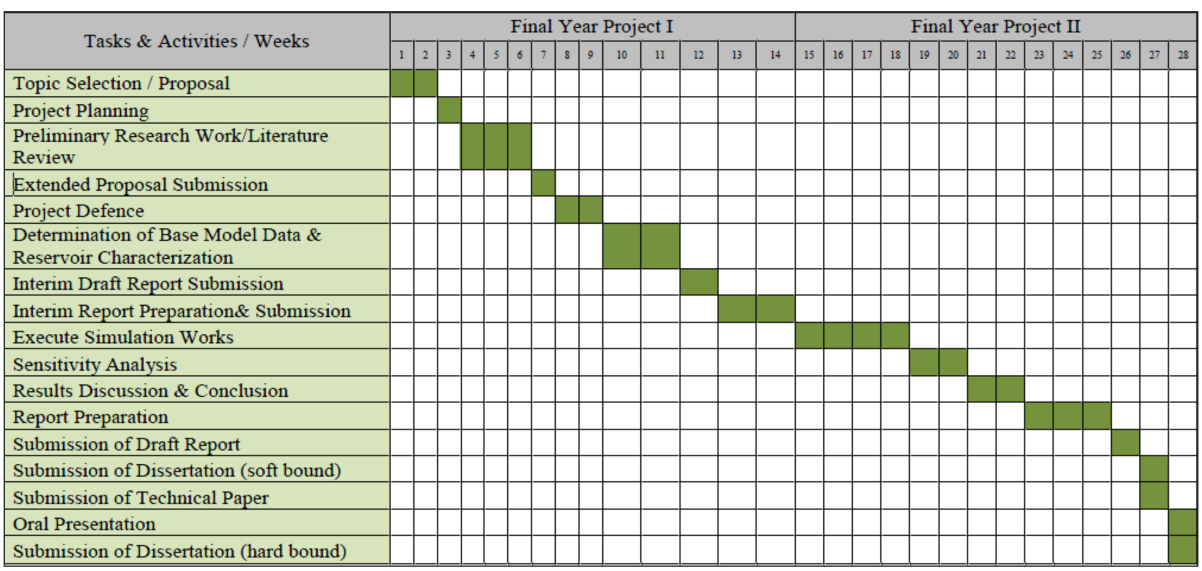

FIGURE 11 : Gantt Chart

CHAPTER 4

RESULTS AND DISCUSSIONS

4.1 Reservoir Simulation Model

A simulation is conducted to investigate the potential of CO_2 EGR and storage and the important parameters that influence the EGR and CO_2 storage such as CO_2 injection rate and difference in reservoir temperature respectively.

Figure 12 has shown the base reservoir model used in this study is based on a synthetic model. It is a conventional gas reservoir which is composed of sandstone. It has homogeneous layer cake geology which contains natural gas at a depth of 3150 meter. The gas reservoir model was created and controlled by number of cells distributions in terms of width, length and thickness.

The dimensions of the geological model, in the X-direction, 10 cells are used, and same numbers of 10 cells are used for Y-direction and finally the Z-direction of 10 cells is used.

Reference depth of the reservoir, pressure and temperature at the reference depth and depth specifying the Water-Gas contact is calibrated to achieve the equilibrium initialization in terms of gas/water contact. It is conducted to indicate a transition zone between gas and water. An initial aquifer zone which is allocated at the bottom cells in the gas reservoir is stabilized. The targets of injector and production wells are placed at two corners of the gas reservoir. Moreover, the relative permeability curves are generated using Darcy's Law to achieve displacement between the gases. The gas reservoir model used for this simulation is contained 0.9 of methane and 0.1 of carbon dioxide. The base case development plan is consists of three injection wells and one production well. They are placed at the four corner of the gas reservoir. Plus, the injection wells are placed in the bottom layer of the reservoir to allow for gravitational forces. The base case for the injection well has an injection rate of 2000 mscf/d.

Property	Value
Reservoir Type	Sandstone
Reservoir Depth	3150 m
Area (X-Y direction)	1000 m x 1000 m y
Thickness (Z direction)	100 m
Grids in X direction	10
Grids in Y direction	10
Grids in Z direction	10
Reservoir Temperature	90^{o}c
Reservoir Pressure	174 bar
Porosity	0.2
Permeability in X-Y	250 md
Permeability in Z	25 md
CO_2 injection rate	2000 mscf/d

TABLE 4 : Base Case of Reservoir Simulation

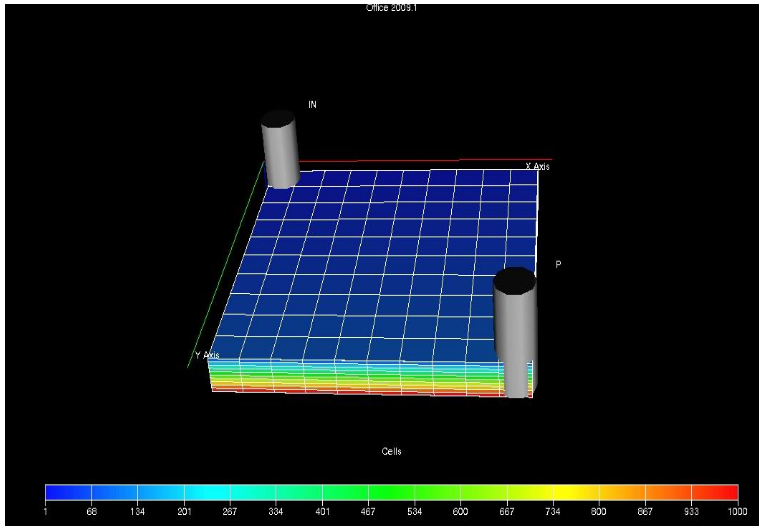

FIGURE 12 : Reservoir Simulation Model by FloViz

4.2 The Effect of Different CO_2 Injection Rate to the Total Gas Production

Figure 13 shows the three CO_2 injection rate into the gas reservoir which are 2000 Mscf/d, 4000 Mscf/d and 6000 Mscf/d. There are two well present which are one injection well and one production well. It is placed lower than 0.8 km in order for the carbon dioxide to achieve its supercritical form. The lowest injection rate of 2000 Mscf/d is set as the base case model.

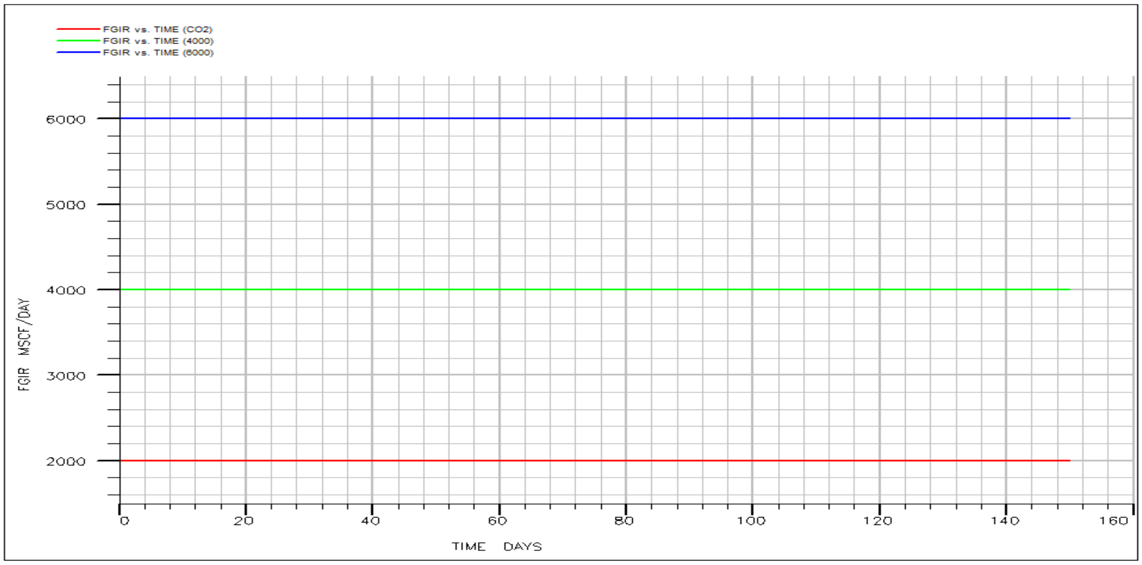

FIGURE 13 : Injection Rate vs Time

Figure 14 has shown the effects of CO_2 injection on the enhancement of natural gas production. Following the increase in CO_2 injection, the increase in total methane production has successfully shown. This increment clearly indicates the positive impact of CO_2 injection on methane recovery. Figure 14 shows that the rise in methane production rate is directionally proportional with injection rate.

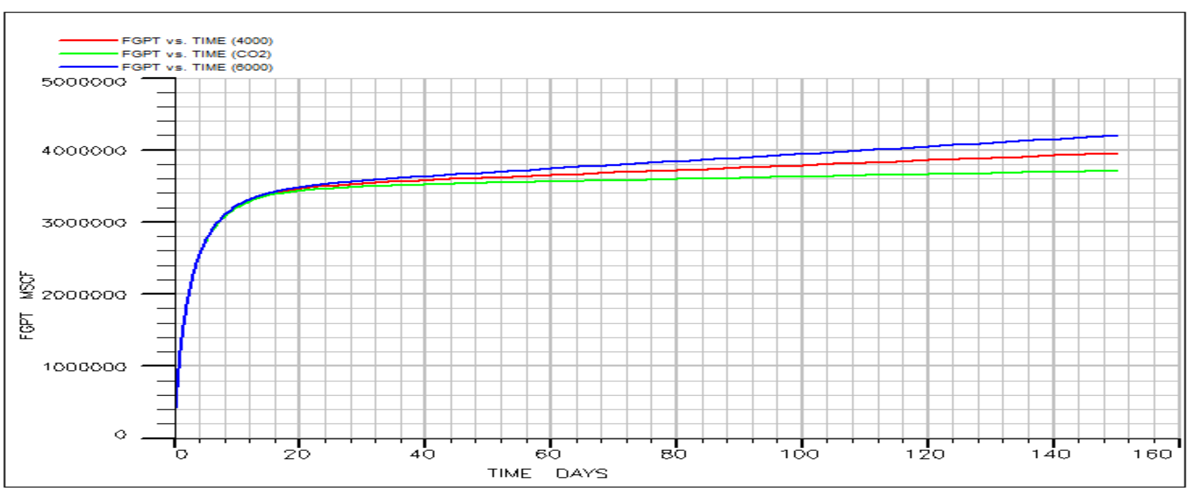

FIGURE 14 : Total Gas Production vs Time

Referring to figure 14, the red line represents the base case of injection rate which is 2000 Mscf/d. After 150 days, the total gas production rises to maximum amount of 3.72 $\times 10^{-6}$ Mscf. A higher injection rate of 4000 Mscf/d is injected to the same reservoir and a slight change of total gas production after 150 days can be observed. The total gas production after injected is 3.95×10^{-6} Mscf. There is an increase of 6.18 % to the total gas production. The highest injection rate of 6000 Mscf/d is then injected to see the effect to the total gas production after 150 days. The total gas production is increased to 4.2×10^{-6} Mscf. The percentage difference between the total gas production of base case and total gas production after 6000 Mscf is 12.9 %. Meanwhile, the percentage difference between the total gas production of base case and total gas production after 4000 Mscf/d is 6.3 %.

Injection Rate (Mscf/d)	Total Gas Production (Mscf)	Percentage Difference with base case (%)
2000	3.72×10^{-6}	
4000	3.95×10^{-6}	6.18
6000	4.2×10^{-6}	12.9

TABLE 5 : Result for the effect of different value of CO_2 injection rate to the total gas production

4.3. The Effect of Reservoir Pressure to the CO_2 storage

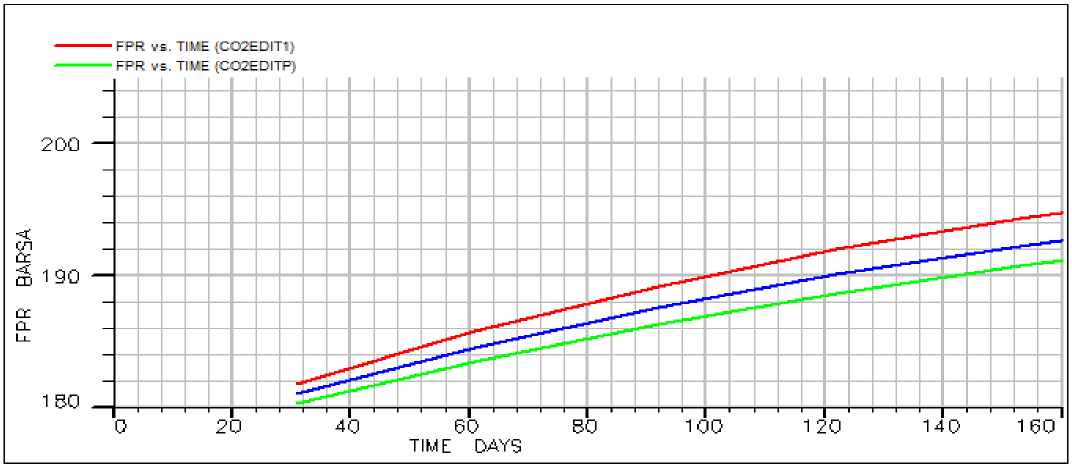

FIGURE 15: Reservoir Pressure vs Time

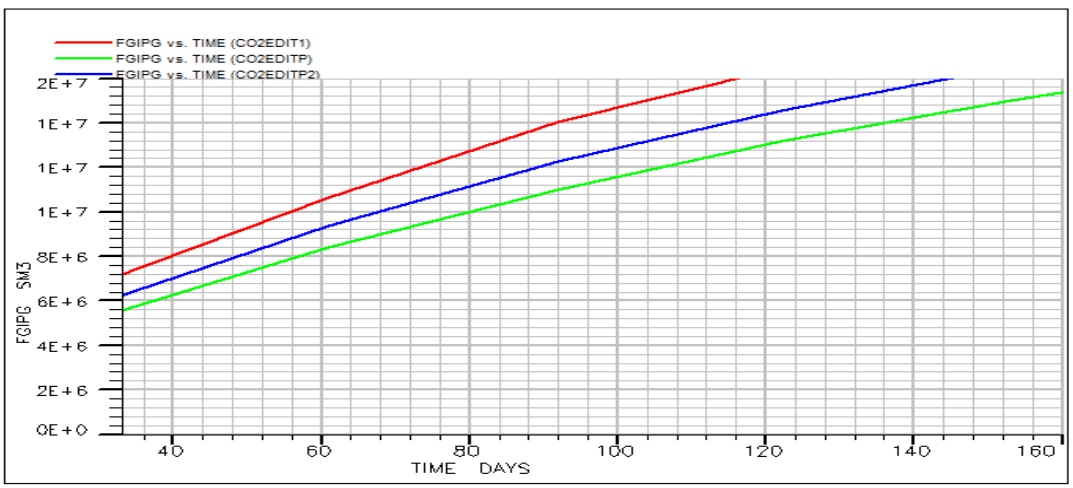

FIGURE 16 : Gas in Place vs Time

Figure 15 has shown the different reservoir pressure used for carbon sequestration. The red line has shown the reservoir pressure with the highest amount of pressure, 182 bar, which affects the gas in place in the reservoir. The highest amount of CO_2 storage was stored at highest reservoir pressure as shown in figure 16 in comparison to the reservoir pressure.

CHAPTER 5

CONCLUSION AND RECOMMENDATIONS

In this study, it is proven that CO_2 injection has successfully enhanced the gas recovery by repressurization. This study focuses on the effect of different value of CO_2 injection rate to the methane production. It is proven that the optimum methane production is by injection a high amount of injection rate. The highest increase in percentage of the total gas production is when an injection of 6000 Mscf is 12.9 %. Not only that, a study of carbon sequestration is done. By having a high reservoir pressure will result in an efficient CO_2 storage. Injecting CO_2 at a higher pressure than the reservoir pressure increases the amount of CO_2 stored in the reservoir. Thus, by enhancing gas reservoir is proven to store CO_2 in it. However, the production of Methane based on the gas production total has not shown a significant increase in amount of total gas production which is a maximum percentage of only 12.9 %. By having this, it is concluded that it is not economical to produce CH_4 by using CO_2 injection for the EGR. It is recommended that Final Year Project should be given more time that so that a detailed research can be done. It is recommended to conduct a detailed economic analysis on this project. Not only that, a study on unconventional reservoir such as Coal Bed Methane can be conducted to compare the results.

REFERENCES

1. Clemens, O., Secklehner, S., OMV; Mantatzis, K., OMW; Jacobs B., OMV."Enhanced Gas Recovery Challenges at the example of three gas fields", SPE *130151*, presented at the SPE/EUROPEPEC,EAGE Annual Conference and exhibition held in Barcelona, Spain, 14-17 June 2010.

2. A. Alhashami, S.R. Ren, SPE and B. Tohidi, SPE, Institute of Petroleum Engineering. Heriot-Watt U,"CO_2 injection for enhanced gas recovery and geo-storage: reservoir simulation and economic", SPE Paper 94129 presented at the SPE/EUROPEPEC,EAGE Annual Conference and exhibition held in Barcelona, Spain, 13-16 June 2005.

3. Mamora, D.D., and Seo, J.G., "Enhanced gas recovery by carbon dioxide sequestration in depleted gas reservoirs", SPE paper 77347, presented at the SPE Annual Technical Conference and Exhibition held in San Antonio, Texas, 29 September- 2 October 2002.

4. Seo, J.G. and Mamora, D.D., "Experimental and simulation studies of sequestration of supercritical carbon dioxide and in depleted gas reservoirs", SPE Paper 81200, presented at the SPE/EPA/DOE Exploration and Production Environmental Conference held in San Antonio, Texas, U.S.A.,10-12 March 2003.

5. Clemens, T., and Wit, K., "CO_2 enhanced gas recovery studies for an example gas reservoir", SPE paper 77348, presented at the 2002 SPE Annual Technical Conference and Exhibition held in San Antonio, Texas, 29 September-2 October 2002.

6. Jikish, S.A., Smith, D.H., Sams, W.S., and Bromhal, G.S., “Enhanced gas recovery (EGR) with carbon dioxide sequestration : a simulation study of effects of injection strategy and operational parameters”, SPE paper 84813, presented at the SPE Easter Regional AAPG Eastern Section Joint Meeting held in Pittsburgh, Pennsylvania, U.S.A., 6-10 September 2002.

7. Oldenberg, C.M., and Benson, S.M., “CO_2 gas injection Enhanced gas production and Carbon Sequestration”, SPE paper 74367, presented at the SPE International Petroleum Conference and Exhibition in Mexico held in Villahermosa, 10-12 February 2002.

8. IEA (International Energy Agency), “Carbon Dioxide Utilization,” IEA Greenhouse Gas R&D Programme, 1997; Table 6.

9. Reichle, D. et al., “Carbon sequestration research and development 2000,” U.S. Department of Energy, DOE/SC/FE-1 (1999).

10. Bergman, P.D., E.M. Winter, and Z.-Y. Chen, “Disposal of power plant CO_2 in depleted oil and gas reservoirs in Texas,” Energy Conver. Mgmt, 38 Suppl. (1997) S211.

11. Galic, G., Cawley, S., Bishop, S. BP and , Gas, F., Todman,. S.,Petroleum Experts Ltd. “CO_2 injection into Depleted Gas Reservoir,”SPE 123788, presented at the SPE Offshore Oil & Gas Conference &Exhibition held in Aberdeen, UK, 8-11 September 2009.

12. H.A. Phale, SPE and T.Zhu, SPE, U. of Alaskan Fairbanks, and M.D. White and B.P. McGrail, Pacific Northwest., “Simulation Study on Injection of CO_2-Microemulsion for Methane Recovery From Gas-Hydrate Reservoirs”, SPE

100541, presented at the 2006 SPE Gas Technology Symposium held in Calgary, Alberta, Canada, 15-17 May 2006.

13. Walker, T., (2002) *Enhanced Gas Recovery Using Pressure and Displacement Management.* Ms. C. Thesis. Louisiana State University.

14. Vogel, W., (2009). CO_2 Sequestration Simulations: A comparison between DuMux and Eclipse.

15. McPherson, B., Lee, R. and Romero V.,(2004). “CO_2 Sequestration and Enhanced Gas Recovery in Depleted Gas Reservoirs: Quantification of Fundamental Chemical and Mechanical Processes Affecting Flow and Injectivity”.

16. CO_2-enhanced Gas Recovery Altmark ,CLEAN , 2008-2011.

17. Retrieved from http://cnx.org/content/m32935/latest/#id4571604 at 8.32 pm on 31st July 2013.

18. Retreived at http://www.co2crc.com.au/aboutccs/storage at 4.12 pm on 12th July 2013.

19. Retrieved at http://www.ccsassociation.org/ at 11.54 pm on 15th July 2013.