

**Faculty of Science and Engineering
Department of Petroleum Engineering**

**Techno-Economic Reservoir Simulation Model for CO₂
Sequestration Evaluation**

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Doctor of Philosophy**

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DECLARATION

To the best of my knowledge and belief this thesis contains no material previously published by any other person except where due acknowledgment has been made. This thesis contains no material which has been accepted for the award of any other degree or diploma in any university.

Signature

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Date

05/03/2014

ABSTRACT

The concept of CO₂ injection for enhanced gas recovery (EGR) is a new area under discussion that has not been studied as comprehensively as enhanced oil recovery (EOR). Limited number of published simulation studies suggests that, natural gas reservoirs are promising targets for carbon sequestration. CO₂ injection allows enhanced production of methane by reservoir re-pressurisation or pressure maintenance. However, none of these published simulation studies were conducted based on experimental data or investigate gas reservoir for CO₂ injection at early stage of production, prior to depletion stage. This process (CO₂-EGR) still a new area under discussion and yet to be tested in the field. High natural gas recovery factors along with concerns degrading the natural gas resource through mixing of the natural gas and CO₂ have led to very little interest been shown in CO₂-EGR. Despite this, natural gas reservoirs can be a perfect place for carbon dioxide sequestration by direct carbon dioxide injection. This is because of the ability of such reservoirs to permeate gas during production and their proven integrity to seal the gas against future escape.

In the wake of the Kyoto protocol, CO₂ emission reduction to control the level of CO₂ in the atmosphere has become an important goal. One possibility of reducing greenhouse gas emission is to separate and inject CO₂ from either production stream or from gas fired power plants into the gas fields. Sequestration process of CO₂ involves separating CO₂ from hydrocarbon gases and compression, transporting it via pipelines into the injection site and injecting it into geological formations. The main primary objective of this research study is to investigate the potential of using CO₂ as injection gas for enhanced natural gas recovery and simultaneously estimate the potential of CO₂ storage. Accordingly, compositional reservoir simulation software (Tempest-ROXAR) was used to create a three-dimensional reservoir model. The simulation studies were investigated under different case scenarios by using experimental data produced by Clean Gas Technology Australia (CGTA). During the experimental work, four sandstone samples were selected and their petro-physical properties were measured individually, such as absolute permeability, effective porosity, residual saturation and CO₂-methane relative permeability curves. These results were imported into the reservoir simulation software to represent different

geological layers in the model. Relative permeability measurement for a gas-gas system has been a great challenge to the research study. Since the gas phases undergo a series of changes at different pressures and temperatures while propagating in porous media. The secondary objective, various CO₂ costs involved in the CO₂-EGR and storage are investigated for each given reservoir simulation case scenario to determine whether this technique is feasible in terms of the CO₂ content in the production as a preparation stage to achieve the economic analysis for the model.

The simulation results outlined what factors are favorable for the CO₂-EGR and storage as a function of CO₂ breakthrough in terms of optimal timing of CO₂ injection and different injection rates. Technically and economically, the results are very promising not just in terms of gas recovery, but also as a method for reducing anthropogenic gas emission simultaneously with increasing ultimate recovery of natural gas.

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RESEARCH WORK AT A GLANCE

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- 2- 'Effects of CO₂ and Acid Gas Injection on Enhanced Gas Recovery and Storage', C. Khan, R. Amin and G. Madden, *Journal of Petroleum Exploration and Production Technology*, 3(1), 2013, 55-60
- 3- 'Economic Modelling of CO₂ Injection for Enhanced Gas Recovery and Storage: A Reservoir Simulation Study of Operational Parameters', C. Khan, R. Amin and G. Madden, *Energy and Environmental Research* 2(2), 2012, 65–82
- 4- 'Reservoir Simulation for Enhanced Gas Recovery: An Economic Evaluation', C. Hussien, R. Amin, G. Madden and B. Evans, *Journal of Natural Gas Science and Engineering* 5(2012), 42–50
- 5- 'CO₂ Capture and Storage Modelling for Enhanced Gas Recovery and Environmental Purposes', C. Khan, R. Amin and G. Madden, in: *Petroleum and Mineral Resources*, ed. F. Khoshnaw, WIT Press, Boston, 81(2012), pp 47–58

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Chapter One

Introduction to the Research

1.1 Research background

With the decline in traditional natural gas resources, companies have been looking to develop natural gas reservoirs that contain significant quantities of CO₂ that can be separated from the gas to meet required export sales gas specifications. It is expected that, in the wake of the Kyoto protocol, more companies will commit to greenhouse gas management in the development of CO₂ associated with natural gas fields (Gaspar et al., 2005). Therefore, global attention to reduce carbon dioxide (CO₂) emissions from burning fossil fuels is increasing due to environmental considerations (see Figure 1.1). Conversely, there is rising interest from petroleum companies to use CO₂ for enhanced oil or/and gas reservoirs (EOR & EGR) to deal with rapid growth in world energy demand (Algharaib and Al-Soof, 2008). These concepts suggest the application of CO₂ injection for enhanced hydrocarbon recovery and sequestration projects is a promising technology application.

The use of CO₂ in enhanced oil recovery has proven to be both a technical and economic success for more than 40 years, but similar level of confidence in this technology has not been applied to the injection of CO₂ for enhanced gas recovery (^aKhan et al, 2012; Oldenburg et al., 2004). Although, the idea of enhanced gas recovery and carbon sequestration through the injection of CO₂ into natural gas reservoirs appears to be technically promising, it has not been the subject of comprehensive testing (Oldenburg et al., 2004; Curtis, 2003; Oldenburg and Benson, 2002; ^bKhan et al, 2012). Economically, the reasons why the CO₂ injection into natural gas reservoirs is less well recognized, is due to the high costs involved in the process of CO₂ capture and storage (CCS). In addition, there remain concerns that the injected CO₂ mixes with native gases in the gas reservoir (^aKhan et al, 2013).

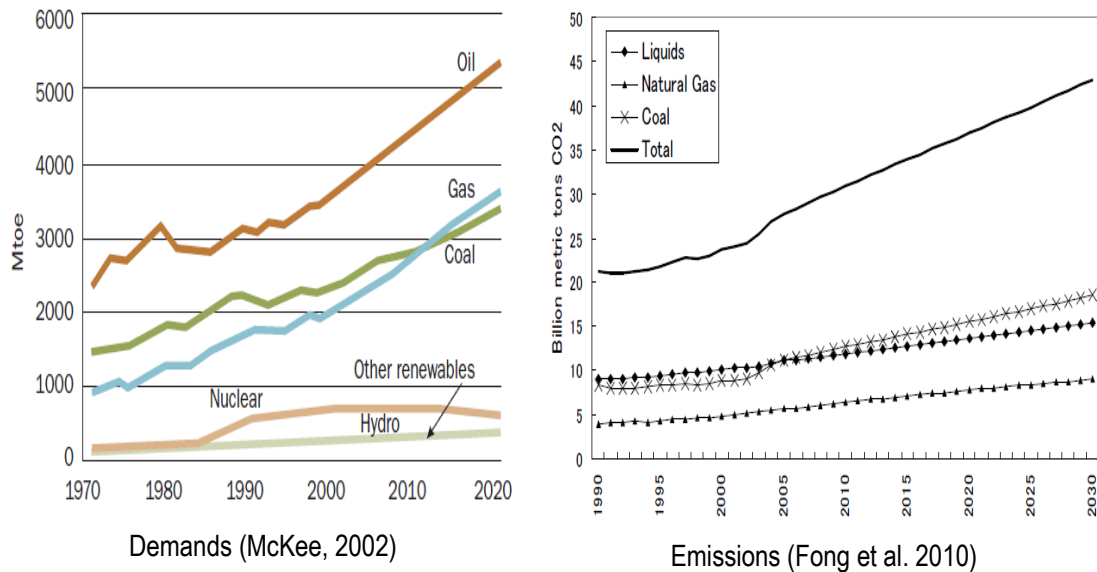


Figure 1.1: Increase in world energy demand and atmospheric CO₂ levels

1.2 Challenges of CO₂ storage in geological formations

In most countries, CO₂ storage is accepted as a future tool for climate change mitigation, rather than as a vital application for industry to achieve carbon intensity targets (Bhargava et al., 2011). This could be due to limited familiarity with CCS. Thus, the concept is not adopted universally. However, in selected countries the concept is either included in a portfolio of processes or adopted only as a policy support (Bhargava et al., 2011). Therefore, while the technology is not mature due to the limited implementations of CO₂ capture and storage projects, but it is still considered to be promising (Mossoly, 2010).

Lack of information, risks and safety concerns dominate public opinion about CCS. As a result, many difficulties arise with respect to site location, slowing CCS demonstration projects, and in some cases, cancellation (Bhargava et al., 2011). Core issues to CCS implementation include: energy security, electricity prices, uncertainty and lack of understanding technical issues involved in CCS to integrate projects (Bhargava et al., 2011; Global CCS Institute, 2013). For example, IPCC (2005) state that challenges to the large-scale application of geologic sequestration in hydrocarbon fields involve fundamental questions, namely.,

- *How mature is the technology?*
- *What are the early opportunities?*
- *What are the storage capacities of the storage options?*
- *Can CO₂ be injected and stored safely?*

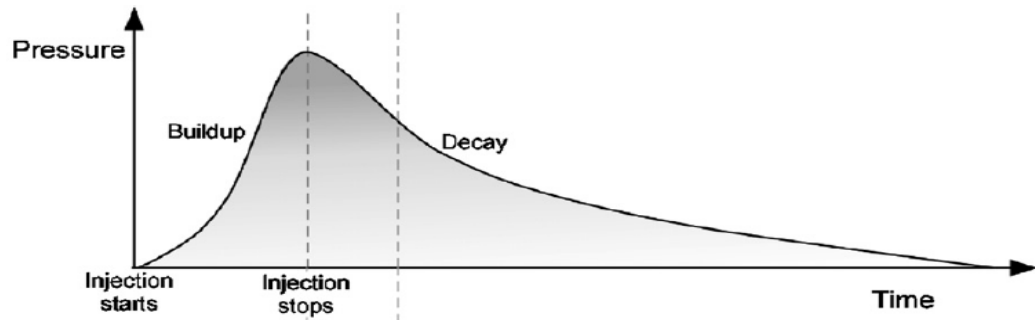
- *What is the fate of the injected and stored CO₂ and what are its effects?*
- *What are the chances that it will leak, and the consequences?*
- *What does CCS cost compared to other mitigation options?*
- *Within the UNFCCC and the Kyoto Protocol, can CCS methods be accommodated?*

Injected CO₂ in geological formations undergoes geochemical interactions, such as structural, stratigraphic and hydrodynamic trapping. The injected CO₂ is trapped either by physical trapping as a separate phase or by chemical trapping where it reacts with other minerals present in the geological formation (IEA Greenhouse Gas R&D Programme, 1990). As time passes, CO₂ becomes immobilized in the geological formation as a function of given long time scales (e.g., hundreds to thousands years).

In general CO₂ injection into the ground leads to increased pressure in the geological formations. Increase in pressure is one of the biggest issues that increase the risks of geo-mechanical fracturing. At cessation stage of injection, pressure in this respect decreases (see Figure. 1.2). Mainly, the security of CO₂ associated with geological storage imposed by injection is increasing with time (Bachu, 2007).

1.3 Existing experience on CO₂ injection for enhanced recovery and storage

In the petroleum industry there are options for sequestering carbon dioxide simultaneously with existing operations in deep underground geological formation (see Figure. 1.3). That is, CO₂ injection into depleted oil and gas reservoirs (EOR & EGR) and CO₂ injection into deep coal seam gas reservoirs are possible storage formations (Solomon, 2007; Stevens et al., 2001). The economics of CO₂ storage in these geological formations mainly relies on the type of reservoir. Particularly when CO₂ storage is combined with enhanced hydrocarbon recovery (IEA Greenhouse Gas R&D Programme, 1990). Under these options, enhanced recovery may have the potential to compensate for the costs involved in CO₂ storage (Mossolly, 2010), and so make geological sequestration attractive. Furthermore, additional value could be created to enhance project feasibility, when carbon credit schemes are implemented (Hussen et al, 2012; ^bKhan et al, 2012; ^aKhan et al, 2013).



Operational Period	Active	Closure	Post-Closure
Trapping Mechanism Dominance	Primary	Increasingly Secondary	
Risk	Increasing	Decreasing	
Monitoring Frequency & Resolution	High	Targeted	Decreasing
Liability	Operator and/or Emitter		State Agency

Figure 1.2: Pressure behavior and risk aspects in CO₂ sequestration (Bachu, 2007)

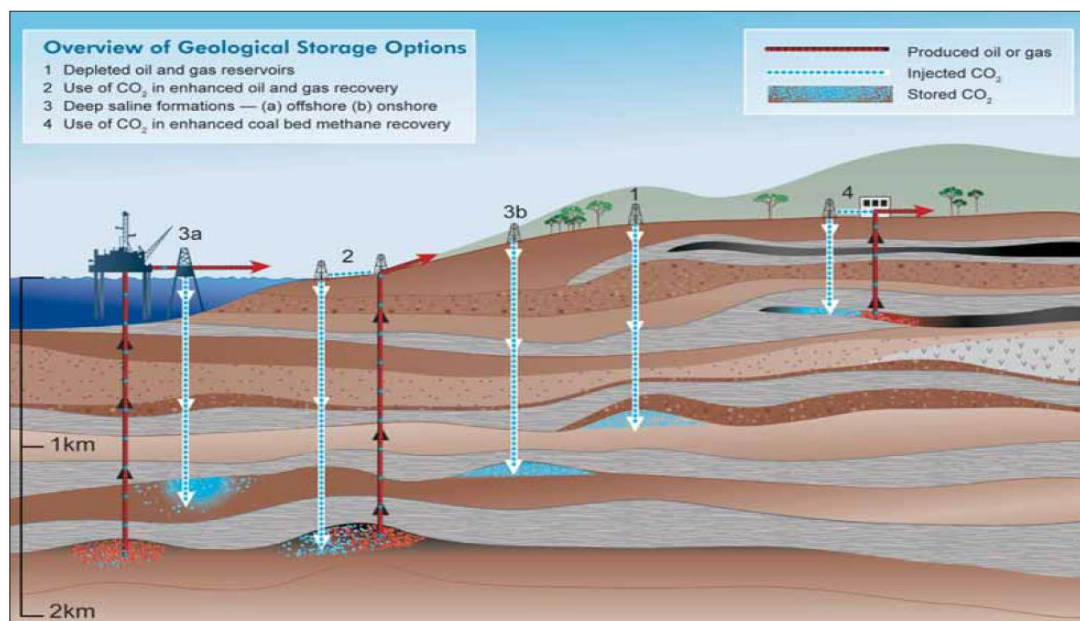


Figure 1.3: CO₂ storage options in deep underground geological formation (IPCC, 2005)

Overall, geological formations that associated with these storage options over geologic time offer promise for secure CO₂ storage (U.S. Department of Energy, 2002). In terms of enhanced recovery, CO₂ is injected into the reservoirs to increase pressure and drive out hydrocarbons initially in place. In practice, the injected CO₂ is mixed with the hydrocarbons initially present in the reservoir. This process results in

high costs for processing the contaminated natural gas (International Energy Agency, 2003).

In this research study emphasis is given to a natural gas reservoir combined aquifer formation where a CO₂ re-injection process is considered. Although there are some published simulation studies that have been carried out to comprehend by which process CO₂ sequestration in a depleted gas reservoir could lead to enhance gas recovery, none of these studies have ever attempted to manifest the effect of mixing (CO₂-CH₄) on the recovery process prior to depleted reservoir (^aKhan et al, 2012). These studies were mainly aimed to reduce greenhouse gas emission in the atmosphere and sequestering in a depleted gas reservoir or in an aquifer. In the year 2005, a project by Gas de France Production Netherland was in progress to assess the feasibility CO₂ injection prior to depletion of the gas reservoir (K12-B) for EGR and storage. However, since then no follow up results have been published on the final gain in reserve recovery (Meer, 2005). Generally, high natural gas recovery factors along with concerns with degrading of the natural gas resource through mixing of the natural gas and CO₂ have led to very little interest been shown in CO₂-EGR (Clemens, 2002).

Economically, (Gaspar, 2005) claimed the major obstacle for applying CO₂-EGR is the high costs involved in the process of CO₂ capture and storage. However, increasing knowledge and experience with contributions of new technologies will probably decrease these costs.

In terms of sequestration, natural gas reservoirs can be a perfect place for carbon dioxide storage by direct carbon dioxide injection. This is because of the ability of such reservoirs to permeate gas during production and their proven integrity to seal the gas against future escape (Oldenburg et al., 2001). Despite of the fact that CO₂ and natural gas are mixable, their physical properties such as viscosity, density and solubility are potentially favourable for reservoir re-pressurisation without extensive mixing (Oldenburg & Benson, 2002; Al-Hashami et al., 2005; Al-Hashami et al., 2005; Oldenburg et al., 2001).

Technically, this phenomenon gas-gas mixing could be supervised via good reservoir management production control measures, because these physical properties of CO₂ undergo changes as the pressure increases (Oldenburg & Benson, 2002; bKhan et al., 2012; ^aKhan et al, 2013).

1.4 Aims and objectives

The aim of the research is to develop a Techno-Economic Reservoir Simulation Model of CO₂ injection for enhanced gas recovery and storage. The first phase of the study emphasizes to identify future scenarios by studying current status and potential of CO₂ injection for enhanced gas recovery and storage, which are initially drawn on relevant experiences from previous studies. The project adopts main elements modules of CO₂ that involved in the process of CO₂ capture and storage from source to sink. Economically, this in return enables transparent and robust analysis of the given gas reservoir. Accordingly, different reservoir simulation studies are conducted for the process of CO₂ injection for enhanced gas recovery and storage under different conditions of interest. The proposed simulation model is expected to consider the price of the developed gas field after injecting CO₂, estimation of investment of gas production and the carbon credit scheme. The primary objectives can be summarized as:

- To develop a Techno-Economic Reservoir Simulation Model to define the technical feasibility and its associated cost elements involved in the process of CO₂ capture and storage, namely capture, compression, transport, and injection for various scenarios of interest by using an integrated reservoir simulation and storage model.
- Investigate the capability of super-critical CO₂ injection and the effects of reservoir heterogeneity on the miscibility of CO₂ and natural gas that accelerate CO₂ breakthrough. Determination of maximum storage capacity for CO₂ to be stored in the reservoir formation and the maximum gas recovery that can be recovered.
- Review injection strategies under different operational parameters at different rates and stages with the design to minimise the risk major of methane contamination before production has been completed. Under such strategies, the CO₂ injection rate and depth are carefully considered in order to determine the optimum injection strategy.
- Perform simulation studies using the experimental data produced by Clean Gas Technology Australia (CGTA) to access the sensitivity of various design and operating parameters to the process.

- Techno-Economic Reservoir Simulation Model integrates the EGR module above with economic quantities that enable calculations of cost and incomes related to CO₂ enhanced gas recovery and aquifer-deposition projects.

1.5 Significance

Carbon dioxide sequestration is a recent development. Even though, uncertainty exists with respect to the process of CO₂ injection into natural gas reservoir, the research project has the potential to provide valuable insights into the process of enhanced gas recovery, gas retention and storage. Furthermore, certain incremental amount of gas will be produced by injecting CO₂ into a natural gas reservoir and maintain pressure decline to offset the costs that associated with the process and achieve the economic feasibility. This Techno-Economic Reservoir Simulation Model for CO₂ injection is believed to have some long term benefits for increasing gas productivity and CO₂ sequestration. During this research study, experimental works were used to investigate the fundamental forces taking place at pore scale such as the significant amounts of CO₂ can be injected to produce significant quantities of additional natural gas. In addition, mixing in the gas reservoir is limited by the physical properties of CO₂ relative to CH₄, by maintaining pressure decline in the reservoir as well as preventing excessive water production, which is normally concurrent with pressure decline. Then, the new developed model will be tested by using commercial reservoir simulation software “Tempest-ROXAR” with respect to the process CO₂ storage and enhanced gas recovery. The technical feasibility of this study, along with reservoir simulation and laboratory studies suggest the potentiality of economic feasibility and also study of the process should be accepted to test the concept furthermore.

1.6 Thesis structure

This thesis explains the challenges associated with technical and economic prospects in natural gas reservoir valuation and management where a miscible CO₂ injection is considered to enhance gas production and storage. The chapters are organized to reflect progress in achieving the above mentioned objectives.

- Chapter two presents an intensive literature review of key features for the concept of CO₂ injection for enhanced hydrocarbon recovery and storage. The main areas that will be discussed in this section consist of the concerns about the concept of CO₂-EGR and storage. Despite of the concerns involved in the process of CO₂-EGR, demonstrations why the concept still has some interesting uniqueness which are beneficial to the process. Next, investigation of the economics of CO₂ capture and storage (which includes capture, compression, transportation and injection for the case study where super critical CO₂ injection is proposed to enhance gas production from the gas reservoir model) is studied. Lastly, illustration of greenhouse gas emission and opportunities of industries under the Kyoto Protocol are considered.
- Chapter three presents the sequence of the experimental processes and the design of the equipment used in the super critical CO₂-methane displacement tests, as well as in the interfacial tension measurements. It also presents the results from core-flooding test carried out on the plugs and relative permeability calculation that achieved at CGTA laboratory.
- In chapter four, simulation of the geological model is developed based on different core plug experimental results from Clean Gas Technology Australia (CGTA) for a known gas field in the North West Shelf region of Western Australia. In the next section, based on the geological three-dimensional model of a base-case is performed without considering CO₂ injection for preparing and optimizing gas recovery and CO₂ storage where the project is under CO₂ injection. Accordingly, different case studies are performed sensitive to injection rates, different stages of injection, injection pressure, and vertical well placement. In order to meet market standard this CO₂ must be separated from the produced natural gas and re-inject into the reservoir. Therefore, the geological model is combined with the economic modules as a function of the mass flow rates of CO₂, depth of the reservoir, number of wells, length of the pipeline from the source to the sink, carbon credit (CO₂ storage) and carbon tax (energy penalty).
- Chapter five shows the case study and an economic analysis covers the application of Techno-Economic Reservoir Simulation Model to illustrate the feasibility of the process CO₂-EGR project under alternative production and

injection strategy schemes. In this study a direct carbon tax and carbon credit effects for CO₂ emission into the atmosphere are considered as a demonstration project for CO₂ storage in addition to extra financial returns on the project.

- The last chapter discusses the conclusions and findings of this study, in addition to presenting potential recommendation for future work.

Chapter Two

Review of Relevant Literature

2.1 Introduction

This chapter presents the potential assessments of technical and economic issues of CO₂ injection for enhanced gas recovery and its storage based on publicly available reports and data on the relevant topics. It highlights the factors at the heart of the reservoir engineering activities as they affect the performance of the process. In some conducted theoretical research, this investigation is based on a small number of criteria, and shown to have major effects on the process. Accordingly, the discussion of CO₂ injection for enhanced gas recovery is addressed to give principle understanding on the topic. Thus, further insights and specific detailed assessment need to be under taken in support of the theoretical framework for the study and demonstration of that natural gas reservoirs can be a candidate for such a particular project.

2.2 Current status and potential of CO₂ injection for enhanced recovery and storage

In general, a typical natural gas reservoir under pressure can potentially recover more than two-thirds of the gas originally in place via primary production. This is considered as high recovery factor compared to that for an oil reservoir. In oil reservoirs approximately one-third of oil originally in place is produced (Jikich et al., 2003; David and Herzog, 2000). High gas recovery factors are among the reasons why CO₂ injection had generated only moderate interest in enhancing gas recovery compared to oil reservoirs (Al-Hashami et al., 2005).

Currently, CO₂ is considered as an expensive commodity in addition to the costs associated with the storage process (Oldenburg, 2003). Technically and economically the process of CO₂ Capture and Storage has not been widely practiced. Once this concept is commercially implemented, the additional gas recovery could offset the costs associated with CO₂ injection (Oldenburg and Benson, 2002). A final reason is

the concern about mixing CO₂ rapidly with the native gases in the gas reservoir and results in a degrade natural gas at production (Rafiee et al., 2011).

In the wake of the Kyoto protocol, CO₂ emissions to control the level of CO₂ in the atmosphere have become an important goal. Because CO₂ is one of the greenhouse gases, which have strong impacts on the environment, with its amount in the atmosphere far beyond what can be ignored (Gaspar et al., 2005).

Current increasing international concerns associated with greenhouse gas emissions have created interest in CO₂ storage as a technique to reduce the level of CO₂ in the atmosphere. Additionally, there is renewed interest in petroleum companies to use CO₂ as an approach for enhanced oil or/and gas (EOR & EGR) relatively to deal with rapid growth in world energy demand (Algharaib and Al-Soof, 2008). Based on the current literature studies, estimates of worldwide sequestration capacity is large. Depleted oil and gas reservoirs are estimated to have the capacity to sequester between 675 and 900 billion tons of carbon (Gt C), saline aquifers between 1000 and 10,000 Gt C, and deep, un-mineable coal beds between 3 and 200 Gt C (Benson, & Cole, 2008). Some countries have many gas reservoirs, while only a limited number of oil fields exist in comparison. Thus, natural gas reservoirs are potentially considered as an attractive option for carbon sequestration by direct carbon dioxide injection into gas fields (Al-Hashami et al. 2005; Clemens & Wit, 2002; Oldenburg, 2003).

Natural gas reservoirs are often considered the most suitable candidate to store more CO₂ than depleted oil reservoirs. A comparison for these reservoirs with same volume of hydrocarbon initially in place demonstrate that ultimate gas recovery (about 65% of GIIP) is almost about two times that of oil (average 35% of OIIP) (Mamora and Seo, 2002).

As a result more space in the reservoir is available to store the injected CO₂. Second, gas is some 30 times more compressible than oil or water (Oldenburg et al., 2001). The accumulation and entrapment of a light gas such as methane (CH₄) testifies to the integrity of natural gas reservoirs for containing gas for long periods. By virtue of their proven record of gas production, depleted natural gas reservoirs have also demonstrated a history of integrity against gas escape (Oldenburg, 2003; Oldenburg et al., 2001). The IEA (International Energy Agency, 2003) estimated that as much as 140 GtC could be sequestered in just depleted natural gas reservoirs globally, and 10 to 25 GtC in the United States alone. In general, these aspects of natural gas

reservoirs for carbon sequestration are widely recognized. Less well recognized is the potential utility of CO₂ injection into natural gas reservoirs for the purpose of enhancing methane production by simple re-pressurization of the reservoirs (Oldenburg et al., 2001). In terms of injection, CO₂ as do other components has a critical pressure and temperature (31 °C and 7.38 MPa). Accordingly, injecting CO₂ at higher stage into any field will behave as a supercritical fluid. However, displacement of natural gas by supercritical CO₂ has not been observed in a comprehensive manner in fields. Research studies emphasised a general lack of understanding supercritical CO₂ behaviour and considerably not well understood (Mamora and Seo, 2002; Hendriks et al., 2004; Global CCS Institute, 2013).

Oldenburg et al. (2001) assert that CO₂ injection and enhanced gas recovery was first illustrated by der Burgt et al. (1992) and Blok et al. (1997). They showed using simulations that the speed with which the injected CO₂ mixes with natural gas in reservoirs indicates that the enhanced recovery of natural gas by CO₂ injection is feasible for a substantial proportion of a chosen reservoir, until the mixing volume becomes large. However, while this concept is established in the literature, concerns remain about the gas-gas mixing and degradation in gas quality during natural gas production. As a result, there has been some progress in developing standard methods regarding to this approach CO₂ injection for similar processes (EOR & EGR) and storage. These results potentially show feasibility for enhance recovery and accordingly sufficient capacity to store a large amount of CO₂ emissions.

2.3 Fundamentals of geological sequestration

Carbon dioxide as a gas is characterized by low viscosity and density that has no specific shape or volume but expands to fill the vessel in which it is contained. Gas in general due to the loose molecular bound, for any change in the state of pressure and temperature will result in a substantial change in its properties. Natural gas reservoirs are composed of a complex mixture of hydrocarbon and non-hydrocarbon components. Physical properties of any gas mixture vary with pressure and temperature. In the following sections some scientific fundamentals of CO₂ are studied to give principle understanding of CO₂ behaviour under different reservoir condition before going further to answer the research questions

2.3.1 Physical properties of CO₂ under reservoir conditions

At normal standard conditions carbon dioxide is a gas with density heavier than air. Carbon dioxide as the other gas components has a critical pressure and temperature. Figure 2-1 shows that CO₂ has the critical temperature of 31.1 °C and 7.38 MPa for the critical pressure in gas reservoirs with typical depths below 1 km (Mamora and Seo, 2000; Jikich et al., 2003; Oldenburg and Benson, 2001). Any circumstances above the critical pressure and temperature of CO₂ encountered in the field will cause CO₂ to change from gaseous state to supercritical condition. Accordingly, it will behave as a super critical fluid, which is neither liquid nor gas, but it has properties of both, thus no distinction can be made. At this stage it has high density like liquid, but still has properties of mixing like gas. As a result, it acts as a gas-like compressible fluid that takes the shape of its container and occupies the entire available volume (Bachu, 2008).

At a depth 1 km CO₂ behaves as a gas with a very low density and can be stored economically (Meer, 2005). Accordingly, at depths greater than 1 km, the formation pressure increases and this tends to increase density. However, at the same time formation temperature increases which tends to increase density. The next effect usually observed is that the density increases with depth (Bachu, 2008). Once it reaches to sense of equilibrium stage, density is almost constant. Figure 2.2 shows this scenario, from the beginning density increases significantly with increasing depth at approximately 800 m and becomes almost constant. The other part of Figure 2.2 show the relative volumes occupied by CO₂. This volume is seen to decrease with depth. At a depth below 1.5 km the density and specific volume become nearly constant, depending on the geothermal gradient surface temperature effects (Benson, & Cole, 2008). At this stage, CO₂ density may reach between 500, 700 to 800 kg/m³ (Bachu, 2003).

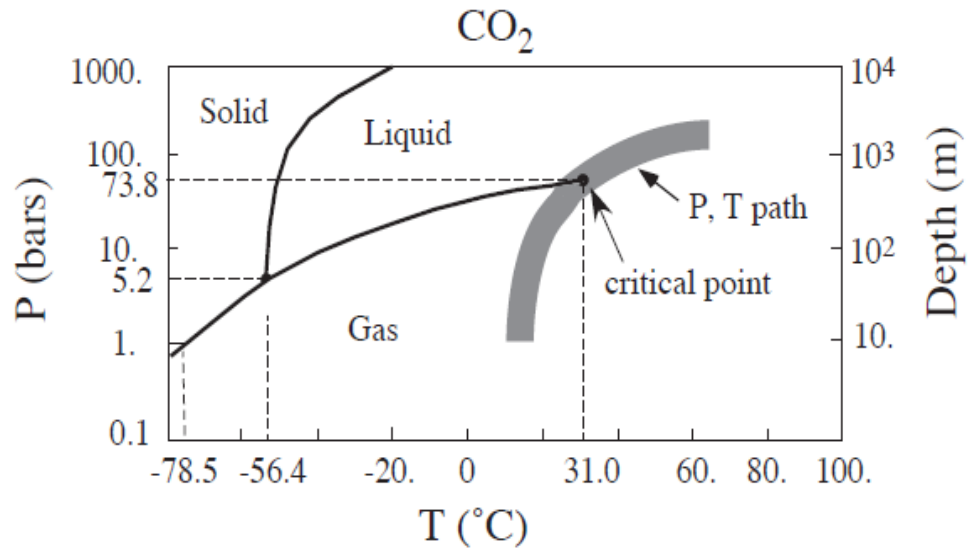


Figure 2.1: Phase diagram of CO₂ showing typical P, T path assuming hydrostatic pressure and 25 °C km⁻¹ geothermal gradient (Oldenburg, 2003)

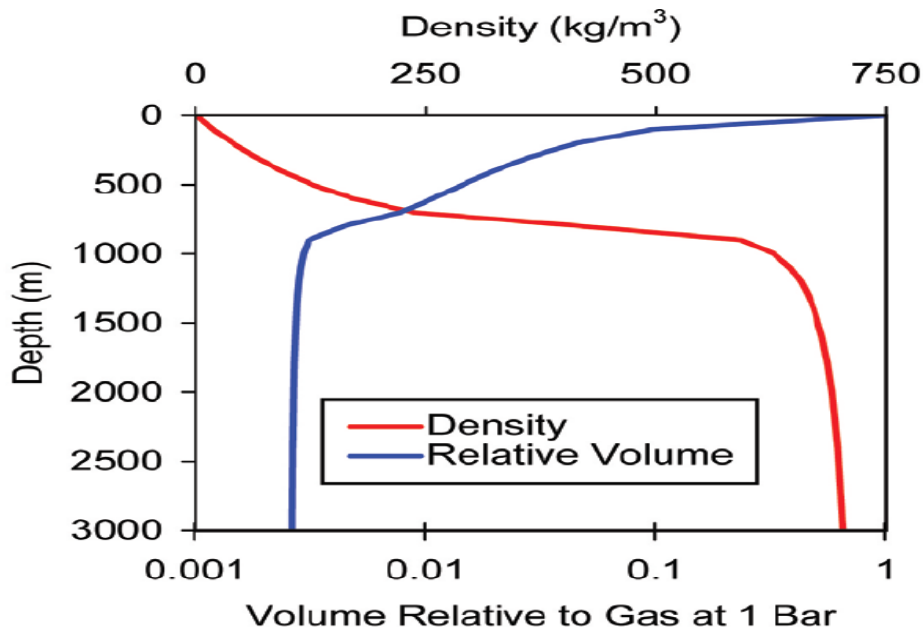


Figure 2.2: Density and Change in volume of CO₂ as a function of depth underground source (Benson and Cole, 2008)

For more comparisons, density of water at normal conditions is 1000 kg/m³. As can be seen from the above graph (Figure 2.2), CO₂ density reaches to a density close to the density of water, but it is still lighter than that of water. Therefore, CO₂ is preferentially injected deep into the ground, because it increases its density. Thus, for the same volume more CO₂ can be stored. It should be kept in mind, being lighter than water it would have properties like oil and attempts to rise via some pathway (Bachu, 2003). On the other hand, methane is super critical above (-82.4 °C and 4640

kPa) and acts much like an ideal gas at the typical critical pressure and temperature of CO₂ (Oldenburg, 2006). Additionally, its density doesn't respond to changed conditions to same extent as CO₂ in terms of pressure and temperature. The degree of real-gas expected by CO₂ can be defined by the Z compressibility factor (Jikich et al. 2003),

$$PV = ZnRT \tag{2.1}$$

where P is pressure (Pa), V is volume (m³), Z is compressibility factor, T is temperature (K) and n is the universal constant (J mol⁻¹ K⁻¹). Figure 2.3 shows a comparison of density between CO₂ and methane, indicates that the density of CO₂ is higher than compared to methane at all relevant reservoir conditions (Oldenburg, 2003).

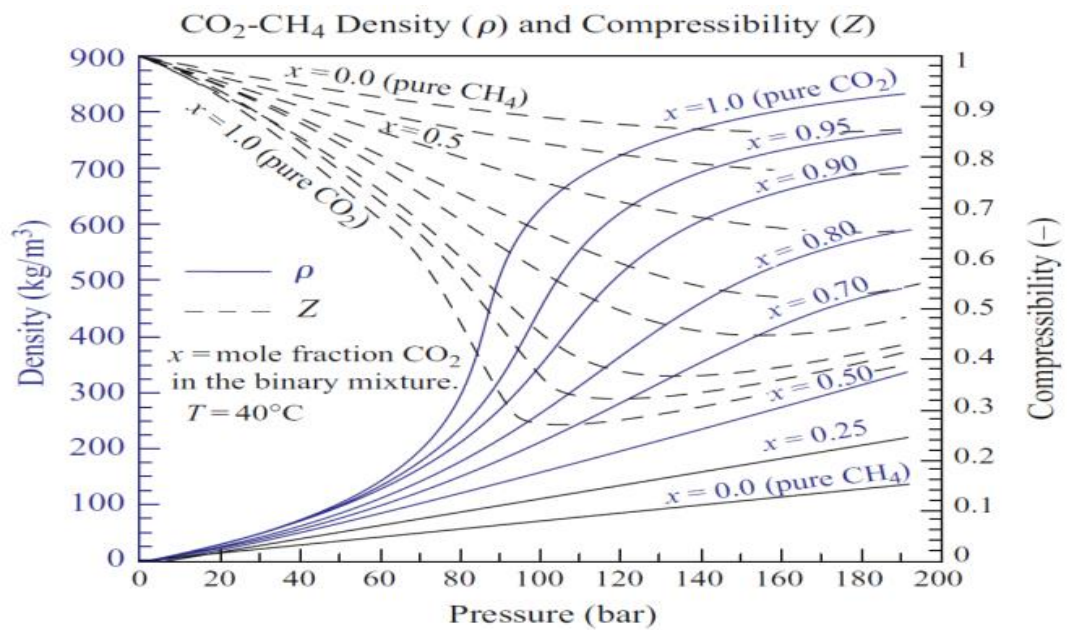


Figure 2.3: Density and Z factor for CO₂-CH₄ mixture as a function of pressure at 400 °C

The viscosity of CO₂ also increases with pressure. Figure 2.4 illustrates the viscosity and density of a CO₂-CH₄ mixture at different pressure ranges. The change in pressure does not change the viscosity of CO₂ to the extent as it is changed for density. Although, the density of super critical CO₂ approaches density of liquid water, the viscosity of CO₂-CH₂ mixture always behaves as gas-like (Oldenburg, 2003). As result, CO₂ super critical is considered as a low viscosity fluid, but, in

comparison, it still has greater viscosity and density relative to methane at all relevant pressure and temperature.

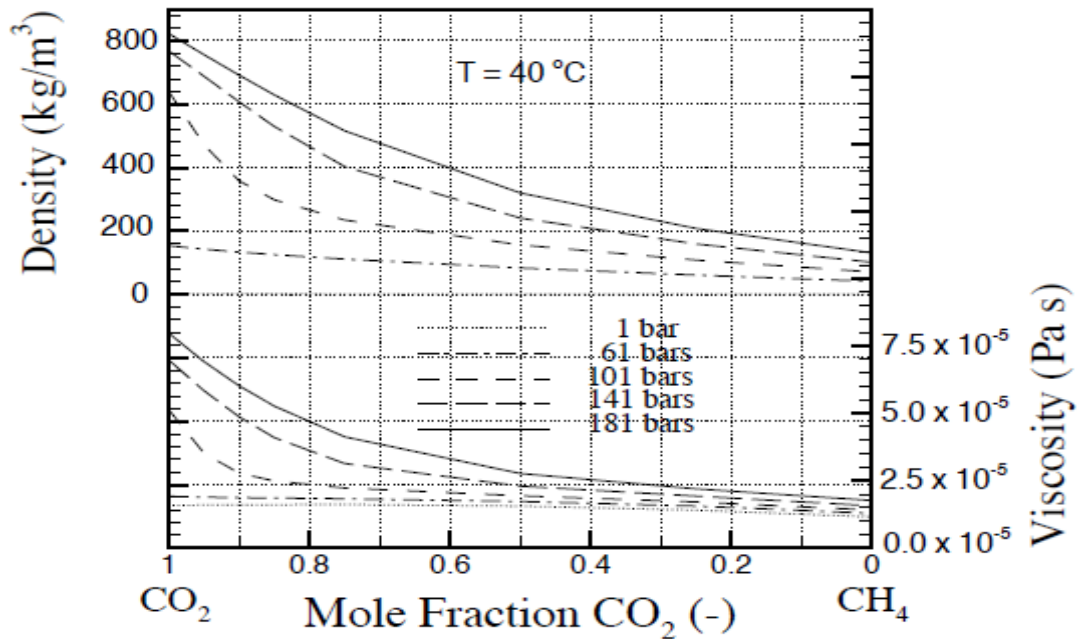


Figure 2.4: Density and viscosity of CO₂-CH₄ mixtures at several pressures at 40 °C. Source (Oldenburg 2003)

CO₂ solubility in the formation water is a function of pressure, temperature and salt composition dependent as well as the salinity and chemistry of the formation water (Hassanzadeh et al. 2008). The solubility of CO₂ increases with increasing pressure and is expected to decrease with increasing temperature, the same plays between the two opposite forces. Nevertheless, if the water is not pure water and has other dissolved solids, then the solubility of CO₂ in that brine decreases with increasing content of other dissolved solids (Bachu, 2003). It can be observed from Figure 2.5, that the highest CO₂ solubility is expected at the lowest temperature when the pressure increases and solubility decreases significantly with an increase in salinity of water formation. This property is very important once a miscible CO₂ injection is considered. When the ground's pores are saturated with water, the injected CO₂ overtime is dissolved in the formations and accumulated at the highest possible place beneath the reservoir. Meer (2005) claims that about 5 to 6 g of CO₂ can be dissolved in 100 g fresh water under subsurface conditions. 4.5 g CO₂ can be dissolved in 1 molar NaCl solution and 2 g in molar NaCl solution. The reservoirs of the Norwegian North Sea have brines with a CO₂ solubility of about of 5 g per 100 g water. For the

brines within the gas reservoirs in the Southern North Sea (typically a 5 molar NaCl solution) however, solubility maybe below 1g per 100 g water. The pH of the formation water will decrease as a consequence of the CO₂ dissolution (Meer, 2005).

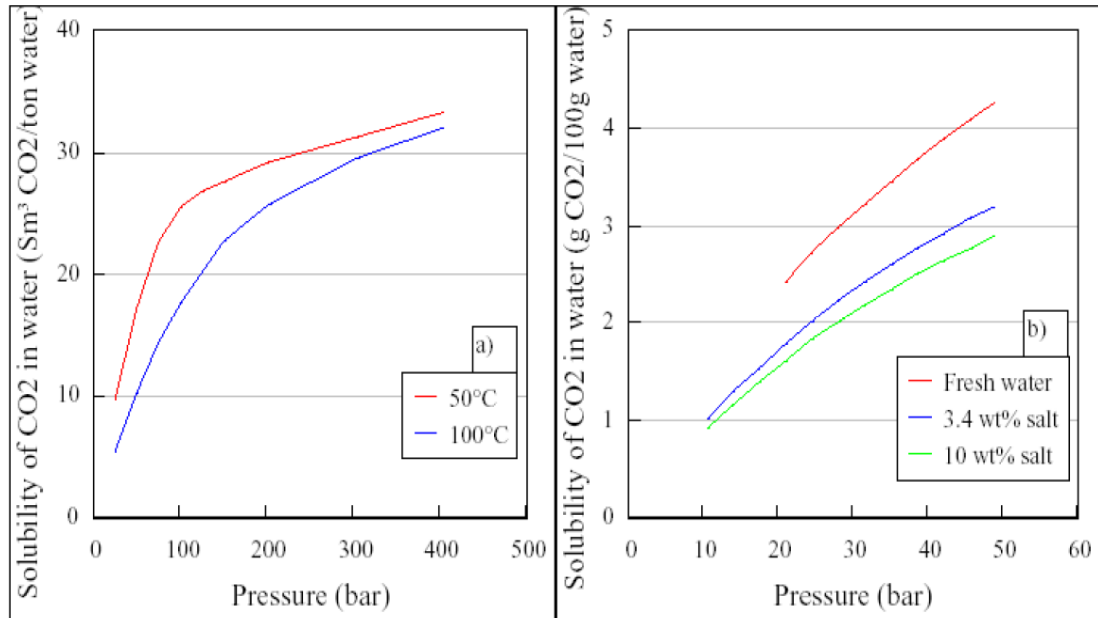


Figure 2.5: solubility of CO₂ in water formation as a function pressure, temperature and salinity, source (Mathiassen, 2003)

2.3.2 Geochemical interactions among CO₂, brine, and formation rocks

Another important characteristic of CO₂ is its dissolution in the formation water, as shown by the reactions below (Equation 2-7). The dissolved CO₂ in the water becomes a weak acid. It will react with rocks or chemical substances in rocks. The dissolved CO₂ in the formation water dissociates ions and initiates trapping mechanisms “solubility trapping (H₂CO₃^{*})” into Ionics trapping (HCO₃⁻ and CO₂⁻) (see Figure 2.6). At this primary stage of CO₂ solubility trapping, the dissolved CO₂ does not exist as a single phase and potentially does not migrate upwards (IPCC, 2005). The dissolution of CO₂ in the water dissociates ions e.g. proton and bicarbonate. The produced ions, e.g. proton will attract the other minerals or aqueous components initially presented in the formation and results in mineral dissolution. In addition, the ions produced during the mineral dissolution (e.g. Ca⁺⁺, Mg⁺⁺ or Fe⁺⁺) in the presence of the bicarbonate that generated due to CO₂ solubility will result in mineralisation (Gunter 1993). At this stage the dissolved CO₂ undergoes mineral trapping such as calcite, magnesite or siderite (Xu et al., 2003). As a result, carbon

dioxide is deposited and it will have properties just as a solid substance and precipitates in filling rock pore spaces.

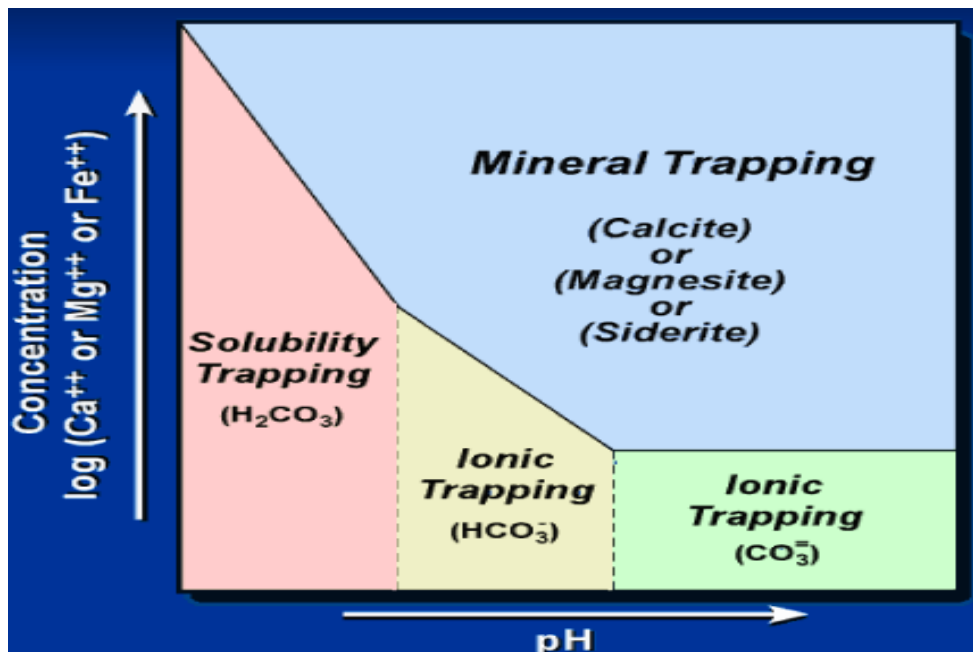


Figure 2.6: Stages of CO₂ dissolution under geological interaction (IPCC, 2005)

Kharaka et al. (2006) investigated the potential of geological sequestration in a saline sedimentary aquifer. The results indicated that during CO₂ injection the brine pH decreases through mixing formation water with the dissolved CO₂, in addition to dissolution of carbonate and iron oxy-hydroxide. These reactions potentially have effects on permeability and porosity (Gaus et al. 2005).

These minerals and carbonate dissolutions possibly could permit sealing or/and cementing CO₂ through the rock formation. Therefore, CO₂ injection may remove toxic trace metals; especially iron oxy-hydroxide into drinkable underground water. If these contaminants migrated, environmentally it will have a major impact on the

potable underground water resulting from CO₂ storage (Kharaka et al. 2006a; Kharaka et al., 2006b).

The literature also suggests that, increased porosity due to dissolution of carbonate cements will decline through time due to subsequent geological reactions such as formation of carbonate minerals and clays (Gaus et al., 2005; Benson and Cole, 2008).

The IPCC (2005) asserts that if CO₂ sequestration is deployed; the effectiveness of geological sequestration depends on a combination of physical and geochemical trapping mechanisms as a function of time. There are four different trapping mechanisms for CO₂ geological storage that potentially contribute to retain the dissolved CO₂ over such long periods of time (Figure 2.7).

CO₂ injection into saline aquifer or hydrocarbon reservoirs is captured or trapped first by structural trapping which includes faults that behave as a permeability barrier in some circumstances, stratigraphic trapping represent the deposited rocks, after when the rock formation changed by gaining organic materials and minerals. In addition, hydrodynamic trapping which represents low permeability below cap rock (IPCC, 2005). These physical trapping mechanisms provide effective barriers to upward CO₂ migration by a layer of shale and clay rock above the sequestration rock formation. The dissolution of CO₂ in formation water occurs through mass transfer from CO₂ phase to aqueous phase whenever the phases are in contact. Under this scheme, CO₂ is stored under the solubility trapping mechanism (Bachu et al., 1994). Initially, CO₂ will start to dissolve into the brine as a function of given pressure, temperature and salinity of the aquifer. Accordingly, the brine saturated with CO₂ will have physical properties higher than that the initial brine (IPCC, 2005). This performance will result in an increase in gravitational effects on the flow process. Consequently, saturated brine with CO₂ will migrate downward in the formation and potentially bring additional unsaturated brine phase in contact with the CO₂ as free gas. In addition, it enhances solubility and distribution of CO₂ pluming. As a result, gas relative permeability experiences the imbibition curve and will lead to trap CO₂ as immobile phase (Bachu 2008). At this stage CO₂ is trapped under residual mechanism. This potentially is important for long term fate of CO₂. Furthermore, due to geo-chemical reaction CO₂_Brine_Rock, CO₂ is expected to remain immobile. . Lastly, the dissolved CO₂ reacts with the rock carbonate minerals. Thus, fractions of the injected CO₂ are converted to solid carbonate minerals. This stage is

favourable because it could immobilize the dissolved fraction of the injected CO₂ permanently in the subsurface as a function of the given long time scales (Gunter et al. 1997).

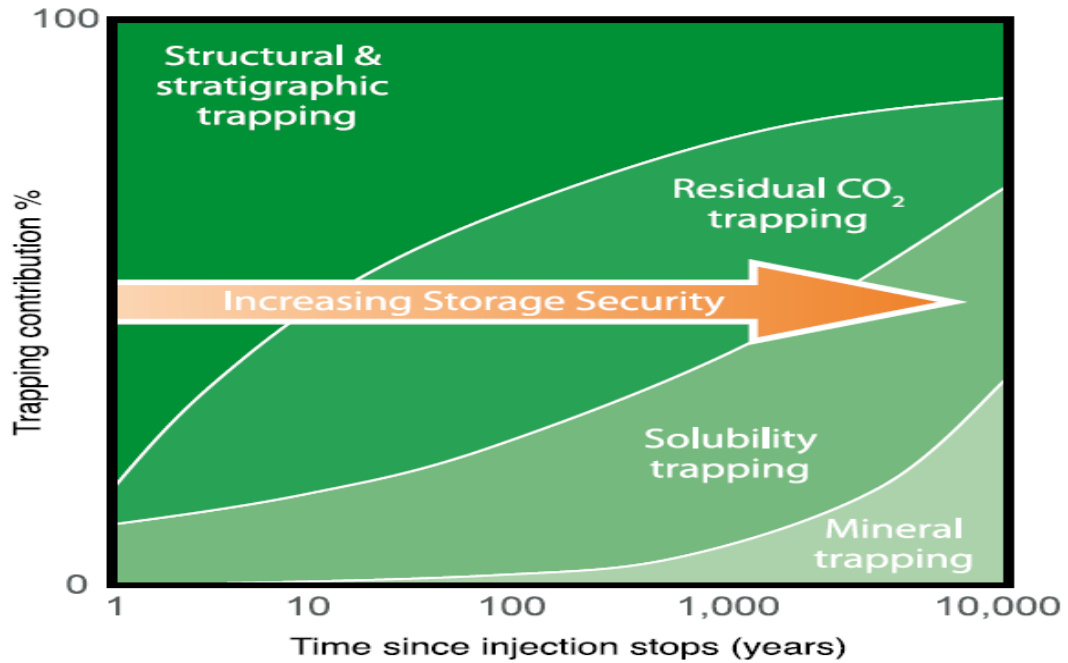


Figure 2.7: Timeframe contribution to storage security (IPCC, 2005)

2.4 Miscible CO₂ injection for enhanced gas recovery and storage

The process of CO₂ injection for EGR proceeds through several stages (Algharaib & Al-Soof, 2008). Figure 2.8 illustrates scenarios where a miscible CO₂ is injected through the required number of the injector wells into the projected gas reservoir. The injected CO₂ potentially sweeps the natural gas from the reservoir, partially dissolves with the reservoir brine and mixes with the initial gas in place CO₂-CH₄ (Al-Hashami et al. 2005). Consequently, it is produced through the producer wells as a mixture. This is a function of well pattern adjusted by the size of the gas field. At the surface, CO₂ from the natural gas production streams is separated and dehydrated through addition of chemicals, to prepare the natural gas production for sale (Nghia, 2003). Traditional CO₂-flood projects are designed to minimize the amount of CO₂ that must be purchased due to its high cost. Despite of the high price of CO₂, environmental consideration is another issue that separated CO₂ from the produced gas, and needs to be compressed and transported to the injection site.

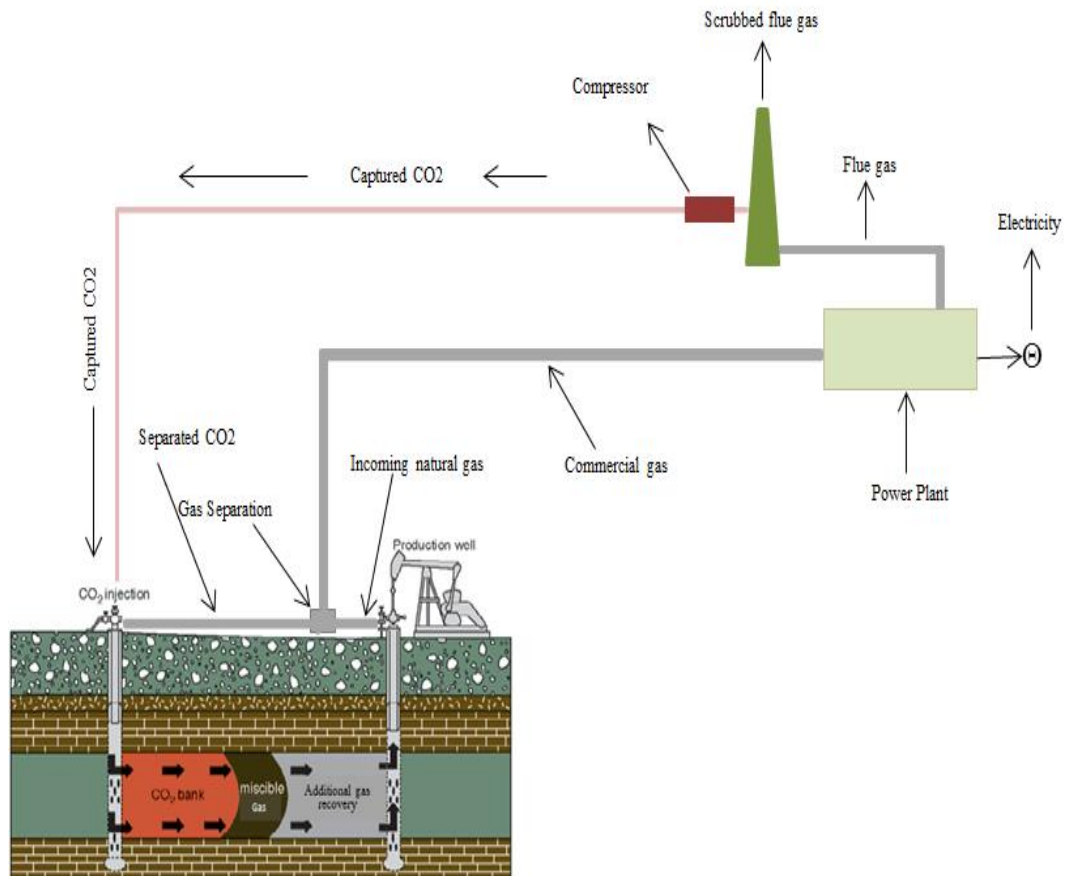


Figure 2.8: Schematic diagram of possible CO₂-EGR system

Even when the CO₂ forced into a reservoir it may not be highly miscible with the initial gas in place on first contact. Accordingly, this depends on the physical properties of the gas reservoir, perforation of the wells and distance between injector and producer wells (Clemens & Wit, 2002). In addition to the CO₂ content of the gas mixture, further CO₂ might be required for injection which is in tune through the feasibility of CO₂ injection for the project. CO₂ injection explicitly intends to store as much as possible of the injected CO₂. It is desirable to choose CO₂ recycle as a re-injection process to maximise the amount of CO₂ storage by the project while recovering a comparable amount of gas to a traditional enhance recovery project (Oldenburg et al. 2004). Finally, it may be possible to optimize operation and the design of re-injection patterns to maximize both gas recovery and CO₂ storage.

2.4.1 Potential of CO₂ injection for enhanced gas recovery in natural gas reservoirs

Several studies have been conducted regarding the process of CO₂ injection for enhanced gas recovery through reservoir simulations. Overall, the prime focus is to simulate the optimum injection strategies on enhanced gas recovery. Clemens and Wit (2002) studied an example gas reservoir and performed four different CO₂ injection strategies for enhanced natural gas production. The purpose of the study was to investigate the effects of CO₂ injection under various scenarios (see Table 2.1). First, gas production started in 1978 as the base case, and continued until the economic limit was reached. The first cases were to investigate CO₂ injection strategies before and after installation of a compressor. Another case involved CO₂ injection for pressure maintenance. Finally, CO₂ injection commenced at the end depletion stage of the gas reservoir. The simulation results suggested that CO₂ injection resulted in a decrease pressure decline in the gas reservoir. In addition, injection at the end of conventional methane production presented the highest incremental gas recovery.

Table 2.1: summary of the different CO₂ injection scenarios

Cases	Injection scenarios	Year	Incremental gas recovery
1	At compressor installation	2004	390 million m ³
2	Before compressor installation	1999	259 million m ³
3	Very early for re-pressurisation	1985	-319 million m ³
4	At end of conventional methane production	2054	750 million m ³

Oldenburg et al. (2001) developed a gas reservoir simulation model for CO₂ injection and enhanced gas recovery through a reservoir simulator TOUGH2. The objective of the study was to illustrate incremental gas production. Two cases were considered for both CO₂ injections that started from at the beginning lifecycle of the project. In the first case, there was only injection from the beginning, with commencement of gas production after reservoir re-pressurization achievement. The second case included CO₂ injection and simultaneous production of gas.

The simulation results showed that CO₂ injection has positive effects on reservoir re-pressurization, meanwhile, increase ultimate gas recovery. A comparison between the two cases suggested that incremental gas recovery for the selected period (5

years) is smaller under the second case compared to that in the first case. Oldenburg et al. (2001) concluded the study by mentioning that the time for such processes depends on CO₂ concentration in the gas production. Al-Hashami et al. (2005) investigated CO₂ injection into a natural gas reservoir by using a compositional reservoir simulator. The objective was to determine time commencement of CO₂ injection. Two different scenarios were performed. In the first scenario, CO₂ injection started from the beginning of gas production and achieved 66% methane recovery. In the second scenario, injection was commenced after gas production started to decline, and resulted in 86% recovery of methane. For both scenarios the proposed project was stopped when the CO₂ concentration reached 10%. Their results indicated that CO₂ injection in the early life of the project is not an attractive option.

Even though, CO₂ injection significantly accelerates natural gas production, the incremental gas recovery decreases (Al-Hashami et al., 2005). Oldenburg et al. (2004) suggested that the optimal timing of CO₂ injection is when the production rate of the field is declining. Clearly, injection from the beginning of hydrocarbon production is risky as the phase behaviour of the reservoir is often unknown. By contrast, injection towards the end of field life when the reservoir is becoming depleted is costly due to the high cost of field rehabilitation expenses.

Clemens and Wit (2002) agreed with Oldenburg et al. (2004) that the announcement of CO₂ injection potentially can be an attractive option when the field is near the abandonment stage. That is, it will increase incremental gas recovery when compared to injection at the other stages. Overall, all authors agree that CO₂ injection at any stages increase ultimate gas recovery, but the exact timing of CO₂ injection is not clear. Thus, the commencement of CO₂ injection requires analysis by field.

Al-Hashami et al. (2005) also studied injection rates of 2 and 20 MSCF of CO₂ injections per day, and their influence on enhanced gas recovery. For both injection rates gas production rate was set at 15 MMSCF/d. Injection and production process were stopped as in the previous case, when CO₂ concentration reached 10%. The authors asserted that CO₂ injection depends on CO₂ content in the gas reservoir and availability of injection facilities. Their results suggested that the higher rate of CO₂ injection, the higher methane recovery is observed compare to the case under lower injection. They also agreed that high injection causes early CO₂ breakthrough and increases CO₂ concentration at the production wells. Economically, this could reduce

the benefits out of the incremental methane recovery for the project. Jikich et al. (2003) agree regarding the results of different stages of CO₂ injection rates on enhanced gas recovery.

Jikich et al. (2003) studied other parameters involved in the process of CO₂ and enhanced gas recovery. The injection of CO₂ at a pressure higher than the initial reservoir pressure decreases enhanced methane recovery compared to lower injection pressures. In terms of brine saturation, it is suggested that less methane is produced for brine with high saturation due to lower gas originally in place. In addition, they also studied the effects of horizontal and vertical injection wells on enhanced recovery. As a result, using vertical wells for CO₂ injection increase slightly methane recovery compared to horizontal wells. Placement of production and injection wells in the gas reservoirs potentially delays CO₂ breakthrough. It has been suggested that it is advantageous to perforate the injection wells in the bottom layers and perforate the production wells in the top layers of the reservoir. Consequently, the injected potential CO₂ re-pressurizes the reservoir longer due to gravity effects, before breakthrough of the production wells.

Another strategy is to locate the injection well at some distance from the production wells. During CO₂ injection, reservoir re-pressurization effects last longer prior to mass transfer allows gas-gas mixing (Feather and Arche, 2010). Also Al-Hashami et al., (2005) investigate the effects of CO₂ injection on enhanced gas recovery with and without consideration of CO₂ solubility in formation water. They indicate that the solubility of CO₂ is higher than methane at all pressures and temperatures. The high solubility of CO₂ results in the reduction of the volume of CO₂ available in the gas reservoir to mix with methane. As a result, CO₂ solubility has the potential to delay CO₂ breakthrough and potentially increase incremental gas recovery. The effect of the molecular diffusion and dispersion of mixing CO₂ with original gases is another factor involved in the CO₂-EGR process. Mechanical dispersion is the distribution process caused by mechanisms of molecular diffusion and velocity. Molecular diffusion is governed by a concentration gradient, unexpected velocities of molecular and indirect “zigzag” flow path in porous media caused by variances in permeability (Meer, 2005).

Mamora and Seo (2000) developed a simulation model where mixing is due to both molecular diffusion and dispersion. The simulation studies considered only two values of CO₂ molecular diffusivity, for the gas phase a value of $1.0 \times 10^{-5} \text{ m}^2 \text{ s}^{-1}$ and

a value of $1.0 \times 10^{-10} \text{ m}^2 \text{ s}^{-1}$ for liquid phase. Al-Hashami et al. (2005) suggested that diffusion potentially increases dispersion and causes mixing between the injected CO_2 and the native gases in the reservoirs. Despite the suggestion of Mamora and Seo (2000) regarding the CO_2 diffusion coefficient, Al-Hashami et al., (2005) indicate that no reliable data is published about CO_2 diffusion when it is a supercritical fluid. Therefore, a sensitivity analysis for CO_2 diffusion involving different values in the simulation studies is conducted Al-Hashami et al., (2005) (see Table 2).

Table 2.2: CO_2 diffusion coefficient

Case	Diffusion coefficient m^2/sec
A	10^{-4}
B	10^{-5}
C	10^{-6}
D	0

The simulation results suggest that high diffusion coefficient value lead to a significant effect on CO_2 dispersion that can potentially cause early breakthrough, the same play occurs between opposite forces. Al-Hashami et al. (2005) conclude that diffusion coefficients with values below 10^{-6} have negligible effects on the results and in this case mixing between the injected CO_2 , and methane is caused due to convective flow. Thus, a 10^{-5} diffusion coefficient is considered to simulate a miscible CO_2 injection at reservoir condition as a supercritical fluid. In addition, Oldenburg and Benson (2001) claim that the displacement process is miscible due to molecular diffusion, but re-pressurisation occurs much quicker than gas mixing. In their study, the equation used regardless of the $\text{CO}_2\text{-CH}_4$ mixture composition to estimate CO_2 molecular diffusivity is:

$$D = \frac{T}{S} = \frac{\frac{k\rho g}{\mu} \times b}{\rho g b(a + \phi\beta)} = \frac{k}{\mu(a + \Phi\beta)} \quad (2.8)$$

where T is transmissivity, S storativity, k permeability, ρ is fluid density, g is acceleration of gravity, b is the layer thickness, μ is fluid viscosity, α is formation compressibility, ϕ is porosity, and β is fluid compressibility.

In terms of CO₂-CH₄ mixture system, the diffusivity is almost 10⁴ times larger than gaseous molecular diffusivity, which represents a value of 10⁻⁵ m² s⁻¹ or lower (Oldenburg and Benson, 2001). In addition, almost similar results were presented in the conducted study in comparison to that from Al-Hashami et al (2005).

2.4.2 Potential of CO₂ storage by CO₂ injection in natural gas reservoirs

During the gas recovery enhancement, the gas reservoir can be considered as a candidate for carbon sequestration. An advantage of this process is that the reservoir can form a proven trap that can hold liquids for thousands to millions of years, where CO₂ is injected into aquifers beneath the reservoir (Meer, 2005). Oldenburg (2003) simulated CO₂ as a storage gas. The results suggested that CO₂ injection as a supercritical fluid allows more CO₂ storage as the pressure increases due to its high compressibility factor. Care must be taken, as natural gas is produced the more the pressure decreases. Thus, an expansion of the compressed is expected due to changes in pressure and temperature. As a result, there is a point when gas production no longer is economically feasible. Gas storage with CO₂ as cushion gas may be a logical choice for further use of gas reservoirs that have been filled with CO₂ during the proposed process of carbon sequestration with enhanced gas recovery (CSEGR) (Oldenburg, et al. 2001).

In the previous section the relevant physical properties of CO₂ injection for enhanced gas recovery and storage have been described. It has been noted that CO₂ is denser and more viscous than methane at all relevant pressures and temperatures. Injecting CO₂ into the aquifer beneath the gas reservoirs will behave as a super-critical fluid with higher density relatively high as water. During injection, the high density and viscosity of CO₂ allow CO₂ migration downward and ensures the displacement of methane due to gravity effects generated by depth variations (Oldenburg & Benson, 2002). In addition to its solubility in the gas reservoirs during the displacement process is beneficial to storing the injected CO₂. These physical properties of CO₂ undergo changes with pressure increases (Oldenburg & Benson, 2002). Therefore, the properties of the gas reservoir seem to serve the practicality of CO₂ injection and sequestration, in addition to limitation of gas-gas mixing (Oldenburg et al. 2004). To gain further insight into the process, well patterns as optimal strategies are studied. Jikich et al. (2003) investigate effects of horizontal and vertical injection wells on

carbon storage. They indicate CO₂ injection through the vertical well decrease the expected volume of injected CO₂ stored.

Feather and Arche (2010) simulate a sample gas reservoir using Sequential Gaussian Simulation. In this study, the priority focus is to examine CO₂ injection into lower parts of the reservoir and a permeability distribution with a horizontal component that can be anywhere between 1 and 10 md. The simulation results indicate injecting CO₂ in the bottom layers of the reservoir is subject to significant gravitational and pressure gradient impacts, and the injected CO₂ preferentially flow downward due to its high density. Higher permeability in the lower region of the reservoir increases CO₂ storage relative to low permeability. As a result, this causes an improvement in sweep efficiency in the lower portion rather than flowing towards top. The effects of variation in permeability of the rock layers and strategy of CO₂ injection rate obtained in the Feather, & Arche (2010) studied agreed with that presented by Rebscher et al. (2006).

Jikich et al. (2003) studied other operational parameters to illustrate favourability of the operational parameters between both carbon sequestration and methane production strategies. The authors stated that CO₂ injection by using horizontal well applications results in an increase in CO₂ storage due to increase in average CO₂ injectivity. Also an increase in length of the injection well has a beneficial effect and maximizes total CO₂ storage. The initial reservoir brine saturation has a significant impact on gas production and CO₂ storage. It is expected less incremental gas production and CO₂ storage where CO₂ is injected into a gas reservoir with initially high brine saturation (Oldenburg & Benson, 2001). This phenomenon may be favourable for injectivity and carbon sequestration in that it allows greater amounts of CO₂ to be injected. However, preferential flow may lead to early breakthrough and is therefore detrimental to enhanced gas recovery.

2.5 CCS risk assessment scenarios for geological storage

CO₂ capture and storage application involves significant challenges. However, no long standing implementation history for such a technology has been presented with regard to risks associated with underground geological storage (Upham and Roberts, 2011). Risk assessment is an essential approach of CCS implantation. It is necessary to continuously assess and update during project evaluations. Most CCS risk assessments tend to focus on health, safety and environment, and are related to long-

term storage issues such as sudden leakage and high concentrations to humans, animals or the environment and resource contamination. In addition to other important risks such as project financial risk, long term liability, regulatory risk and public opinion risk (Forbes et al., 2008).

Implementation of CO₂ capture and storage is a recent technology and there only patchy awareness of it (IPCC, 2005). CCS is costly, and requires long-term commitments to safe guard geological CO₂ storage sites against a risk of leakage. Thus, there is a need to test the technology and demonstrate the feasibility of the technology with respect to physical risks that are associated with concerns involved in the storage aspect of the CCS chain. Financial and governance are other risk factors to be managed (Upham and Roberts, 2011).

Surface risks of CO₂ leakage from pipelines during transportation occur, although leakage rates are small. Currently there are standards for pipeline quality for natural gas in the context of enhanced oil recovery applications which establish the terms and condition under which the pipeline may be built and initially operated (Forbes et al., 2008). However, some standards may not be appropriate under large scale deployment would be required for CCS. The IPCC (2005) states that pipeline transport of CO₂ requires detailed design in terms of detailed route selection, over-pressure protection, leak detection and other design factors. However, no major obstacles to pipeline design for CCS are predicted. Carbon dioxide acts as asphyxiant at levels of 7-10% by volume of air and can be dangerous to humans (IPCC, 2005). For this reason, leakage from storage of CO₂ in geological reservoir might be a serious problem, especially if sited in a populated area. In general risks involved in geological sequestration consist of global and local risks. These risks involve CO₂ leaks out from the geological formation into the atmosphere. As a result, this may contribute significantly to climate change, in addition to local hazards on humans such as environments and underground water (IPCC, 2005).

The risks associated with the geological storage of CO₂ would be analogous to those of natural gas storage, EOR, and deep underground storage of acid gas, all of which have a history of safe operation. The potential pathways by which CO₂ could escape back into the atmosphere such as: (a) sudden leakage due to well failure that may create a channel for CO₂ to flow through the formation penetrated for the injection wells to the surface; (b) gradual leakage and transition through unknown faults or fractures in the reservoirs (Forbes et al. 2008); and (c) spillage from the confining

structure. This last type of leakage is least likely to occur and in many cases there will be multiple layers above the primary coning layer that will help mitigate the movement of the CO₂ (Esposito, 2010). Figure 2.9 illustrates the potential of CO₂ injected into geological formations and escape into the atmosphere.

Ground water can be affected by both CO₂ injection and leaking, thus it can displace existing saline groundwater directly into an aquifer zone. The displacement of saline ground water might have high levels of dissolved ions and metals that contaminate the groundwater during the process of CO₂ injection (Esposito, 2010). In addition, techniques to remove CO₂ from ground water are available, but they are likely to be costly. If leakage into the atmosphere has occurred, this type of release is likely to be detected quickly and stopped using techniques that are available in terms of engineering and administrative controls in the oil and gas industry. Storage systems can be managed by using monitoring methods (during the injection stage) to observe underground water, geochemical changes and pressure changes. These monitoring methods are promising as a management strategy to have intervention plans ready in case of unexpected abnormal behaviour of CO₂ such as sudden and long terms detection of leakage (Reveillere and Rohmer, 2011).

Zhang et al. (2010) studied monitoring techniques to assess geological conditions for the DF1-1 gas field South China as a first CO₂ storage project in China. The results indicate that the DF1-1 is safe and reliable in terms of gas leaking due to its good reservoir integrity and analogy to long history of safe gas production in the field.

For “well-characterized and properly managed storage sites”, it is very likely of 90% to 99% of the CO₂ in the given geological reservoir will be retained for over 100 years. There is also probability from 66% to 90% for CO₂ in the geological storage that would remain for over 1000 years. These estimates are based on simulations of CO₂ storage in various types of geological reservoirs, as well as on the long, safe history of underground natural gas storage worldwide (IPCC, 2005).

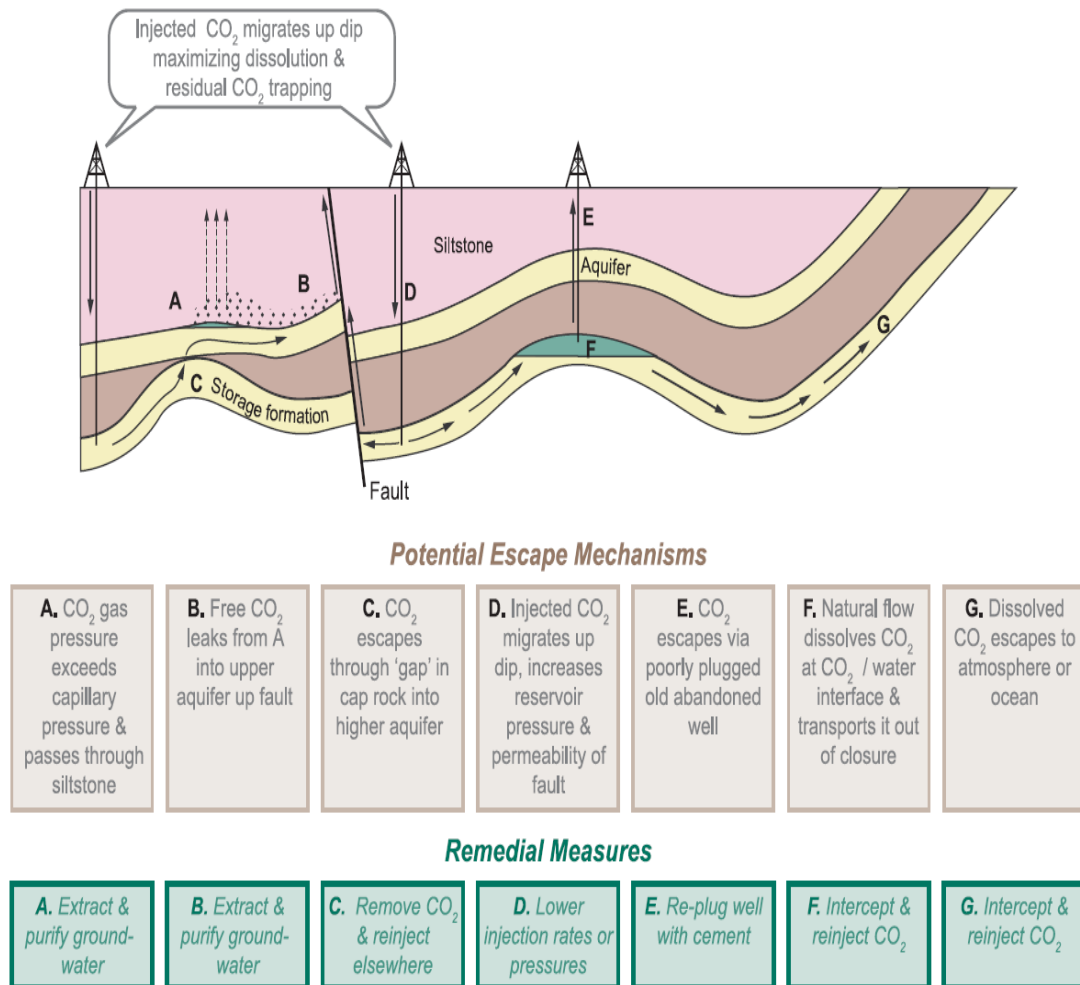


Figure 2.9: Potential leakage and remediation technique for CO₂ injected into saline formation (IPCC, 2005)

2.6 Techno-economic model for enhanced gas recovery and CO₂ storage technology chain

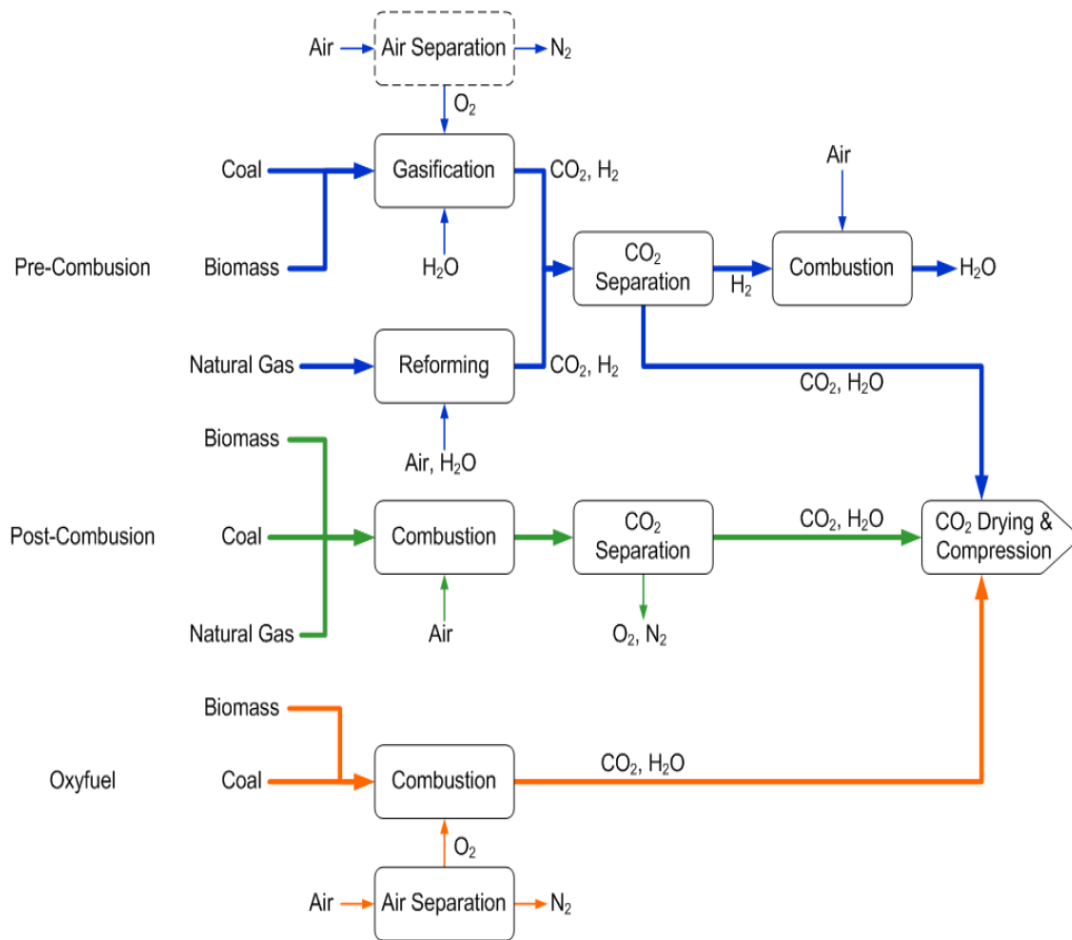
Since the process of CCS has potential to enable using fossil fuels with lower emissions, many methodologies and engineering designs have been attempting to make the process economically more feasible and environmentally safe. In particular, research is being conducted to illustrate effects of the main parameters on particular aspects of CCS. For instance, storage security and optimisation, monitoring and verification, risk assessment and mitigation, and cost reduction (Zhang et al., 2006).

The general idea of CCS is to separate CO₂ from the other emissions from the flue gases of power plants and/or other industrial complexes, and then transport them and store in a location separated from the atmosphere for a period of many years (Nguyen and Allinson, 2002). The cost of the capture and storage of carbon dioxide can conveniently be divided into costs for capture, separation, compression, transport

and storage (Gusca et al., 2010). For each of these categories, in the following section, a review of the literature on the cost of CCS components is given and the main issues underlying these costs are discussed.

2.6.1 Carbon dioxide separation and capture module

The base sources of CO₂ capture are fossil fuel from power plants, fuel processing plants and the other industrial plants. The basic systems for capturing CO₂ from the processing and power plants consist of pre-combustion CO₂ capture, where CO₂ is removed from the fuel prior to oxidization; post-combustion CO₂ capture, where fuel is combusted normally in a boiler or turbine and the CO₂ is removed from the flue gas stream; and oxy-fuel combustion, where the fuel is combusted with nearly stoichiometric amounts of oxygen in an atmosphere of CO₂ (IPCC, 2005). Figure 2.10 summarizes these systems in simplified form. Different measures of CO₂ capture cost are presented with an overview of factors that affect costs and ability to compare published estimates on a consistent basis (IPCC, 2005). Similarities and differences between the existing methodologies have been documented by Hendriks et al., (2004); David and Herzog (2000) to investigate the economics of CO₂ capture. This assignment is achieved based on different types of power plants such as, integrated coal Gasification Combined Cycle (IGCC) power plants, Pulverized Coal (PC) power plants, and Natural Gas Combined Cycle (NGCC) power plants (Hendriks et al., 2004; David and Herzog, 2000).

Figure 2.10: CO₂ capture system (Rubin et al. 2008)

The costs of CO₂ capture are usually calculated based on CO₂ capture at reference plant (no capture), and CO₂ at capture plant which consists of CO₂ separation and compression. In general, these cases attribute to energy consumption and cause an increase in electricity generation. This energy is originally produced by combustion of a fuel. This will lead to a reduction in the generation efficiency and net power outputs when the two cases are compared. In general, power plants capturing CO₂ will consume more fuel (Rubin et al., 2008). Furthermore, the CO₂ volumes created to enable processing the capture generally is considered, because initially this volume of CO₂ is being emitted when it is compared to the reference plant. As a result, a differential between CO₂ captured and CO₂ avoided need to be considered (see Figure 2.11).

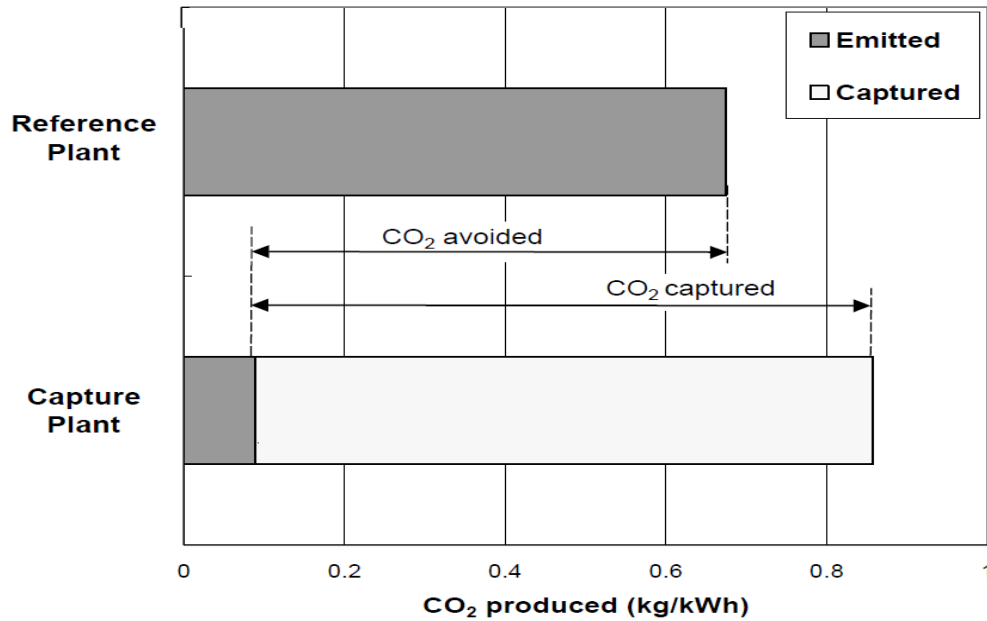


Figure 2.11: Difference between CO₂ avoided and CO₂ captured (David, 2000)

A widely used measure for CO₂ capture and storage cost is the cost of CO₂ avoided or mitigated. This value is expressed as the difference in cost of electricity (COE ϕ /kWh)_{capture} - (COE ϕ /kWh)_{reference} in a given period of time divided by the difference in CO₂ emission intensity (t/kWh)_{reference} - (t/ kWh)_{capture} for the period of time. In addition, cost of CO₂ capture is defined as the difference in cost of electricity divided by volumes of CO₂ capture (CO₂ kWh⁻¹)_{capture}.

$$\text{Cost of CO}_2 \text{ Avoided US\$/tonne} = \frac{(COE)_{capture} - (COE)_{reference}}{(t / kWh)_{reference} - (t / kWh)_{capture}} \quad (2.9)$$

$$\text{Cost of CO}_2 \text{ Capture US\$/tonne} = \frac{(COE)_{capture} - (COE)_{reference}}{(t / kWh)_{capture}} \quad (2.10)$$

Therefore, cost of CO₂ capture model is usually developed in terms of the generated electricity without CO₂ capture facilities (reference plants) and the electricity generation from CO₂ capture facilities (capture plants), in addition to their comparisons (Herzog,1998). In general, modelling CO₂ capture is developed based on two categories, such as inputs of data description and basis of data description. Inputs of data description consist of two main groups of data, and each group consists of three independent variables. A number of papers have addressed this issue and identified the principal sources of cost differences and variability (IPCC, 2005;

David, 2000; David and Herzog, 2000). The first group subdivided into: (a) capital cost, in \$/kW; (b) cost of electricity due to operation and maintenance, in mills/kWh; and (c) heat rate, in Btu/kWh, defined on the lower heating value (LHV) basis.

These inputs estimate the cost of electricity for the power plant in case where there is no CO₂ capture. The second group represents CO₂ at the capture plant and consists of: (a) incremental capital cost, in \$/kg of CO₂ processed per hour; (b) incremental cost of electricity due to operation and maintenance, in mills/kg of CO₂ processed; and (c) energy requirements of the capture process, in kWh/kg of CO₂ processed.

Each of these evaluations provides a different potential on CO₂ capture for a particular power plant. A second category is based on data description which consist demonstrates the performance of the power plant. That is,

- (a) The capacity factor, or number of operating hours per year (f);
- (b) The capital charge rate (r), in % per year. It is used to annualize the capital investment of the plant and can be exactly correlated to the cost of capital. Specifically, the capital component of the cost of electricity equals the capital charge rate times the capital cost divided by the number of operating hours per year; and
- (c) The fuel cost (FC), in \$ per million BTU, defined on the lower heating value (LHV) basis.

The combination of these categories represents an economic engineering potential and demonstrates the additional cost to capture CO₂ for a particular plant. The capture efficiency is usually about 90% in the reviewed studies. To compare the different types of capture plants on a similar basis, the capture efficiency needs to be kept constant. Consequently, it has been suggested to set the capture efficiency at a constant value of 90% (David and Herzog, 2000).

These two categories are considered as a representative for cost calculation of the CO₂ at the reference plant and the costs of CO₂ at the capture plant. A comparison between these two cases result in calculating the incremental cost of electricity, energy penalty and mitigation costs as a function of a given mass flow rate of CO₂ per tonne (Gusca et al. 2010). For most large sources of CO₂, the cost of capturing is the largest contributor to overall CCS costs and thus is a focus of cost reduction efforts (Su et al., 2008).

Literature studies show large variations in the unit values due to different assumptions for the technical issues associated with plant design and operation as the same for economic and financial assumptions. This observation suggests that large differences in reported capture cost from the published studies.

2.6.2 Carbon dioxide compression module

An important contribution to the total cost in the CCS process comes from the capital and operating costs for compression, including to cooling and dehydration equipment (Smith et al., 2002). For estimating compression costs, the required amount of compression and the unit costs of compression should be considered. However, these two elements can vary by project. Much of the cost is associated with the power required for CO₂ compression in a multi-stage compressor. In addition, compression costs are considerably higher for small flows (Gusca et al. 2010).

To transport CO₂ in a pipeline, it must be compressed to a pressure above 8MPa (1200psi) to ensure that we achieve a single phase flow and keep the density high (Nguyen 2003). Thus, when CO₂ is in a gas phase, a compressor is used to increase the pressure from 0.1 to 7.38 MPa, while a pump is used when CO₂ is in liquid phase in order to boost the pressure from 7.38 to 15 MPa or to whatever final pressure is desired (Akinnikawe et al. 2010). Transportation of CO₂ at lower densities is inefficient because low density of CO₂ causes relatively high pressure drop per unit length. Moreover, by operating the pipeline at pressures greater than the CO₂ critical pressure of 7.38 MPa, temperature fluctuations along the pipeline will not result in the formation of gaseous CO₂ and the difficulties encountered with two-phase flow (McCoy, 2008). In this stage power is required for the compressor and pump in order to compress the required volume of CO₂. Figure 16 illustrates the power requirement as a function CO₂ mass flow rate. Figure 17 shows cost per kw energy requirement for each compressor and pump. Energy for CO₂ compression might be supplied by a CO₂ emission source such as a power plant. Therefore, it is necessary to consider how much CO₂ would be produced to generate the energy for compression CO₂. Usually, the energy requirement for CO₂ compression is higher from the power plant sources compared to that which comes from hydrocarbon reservoirs. For example, CO₂ production from hydrocarbon reservoirs with high pressure reduces the power requirement for CO₂ compression (Nghia, 2003). In this section, the following formulas adopted from McCollum and Ogden (2006) are employed to provide the

capital cost of CO₂ compressors and pumps (as cited in Su et al. 2008; Akinnikawe et al. 2010; Gusca et al. 2010).

The compressor power for each stage “W_{s,i}” [kW] is given by the following equation:

$$W_{s,i} = \left(\frac{1000}{24 * 3600} \right) \left(\frac{m \times Z_s \times R \times T_{in}}{M \times \eta_{is}} \right) \times \left(\frac{k_s}{k_s - 1} \right) \times \left[(CR)^{\frac{k_s - 1}{k_s}} - 1 \right] \quad (2.11)$$

where R is the gas constant, kJ/kmol-K, M is the molar mass of CO₂, kg/kmol, T_{in} is the CO₂ temperature at compressor inlet K, η_{is} is the sentropic efficiency of compressor; Z_s is average CO₂ compressibility of each stage, k_s is the average ratio of specific heats, m is the CO₂ mass flow rate tonne/day, and CR is the compression ratio at each stage [-].

The pumping power requirement “WP” [kW] equation is:

$$W_p = \left(\frac{1000 \times 10}{24 \times 36} \right) \times \left(\frac{m \times (P_{final} - P_{cut-off})}{\rho \times \eta_p} \right) \quad (2.12)$$

where P_{final} is the final pressure, Mpa , P_{cut-off} is the cut-off pressure (switching from a compressor to a pump), Mpa and the ρ is the density of CO₂ during pumping, kg/m³ and η_p efficiency of the pump.

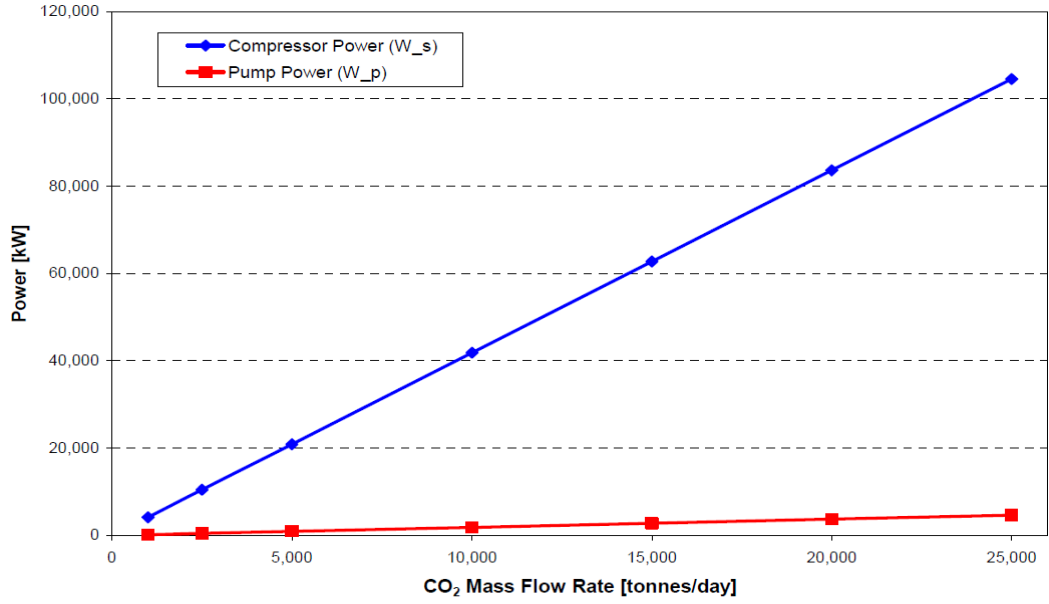


Figure 2.12: Power requirement of compressors and pumps as a function of CO₂ mass flow rate (McCullum and Ogden, 2006)

Capital cost of the compressor “C_{comp}” [\$] is determined by

$$C_{comp} = m_{train} \times N_{train} \left[(SSC) \times (m_{train})^{-0.71} + (CEC) \times (m_{train})^{-0.6} \ln \left(\frac{P_{cut-off}}{P_{initial}} \right) \right] \quad (2.13)$$

where N_{train} is the number of parallel compressor trains [-], m_{train} is the CO₂ mass flow rate through each compressor train [kg/s], SSC is the preliminary site screening for compressor, CEC is the candidate evaluation for compressor, P_{final} is the final pressure, MPa, and $P_{cut-off}$ is the cut-off pressure, MPa.

The capital cost of the pump “C_{pump}” [\$] is given by

$$C_{pump} = \left[(SS_p) \times \left(\frac{W_p}{1000} \right) \right] + CE_p \quad (2.14)$$

where SS_p is the preliminary site screening for pump, CE_p is the candidate evaluation for pump, and W_p is the pumping power requirement [kW].

In terms of the capacity factor (CF) and electricity prices (Pe), the total annual cost of electricity (\$/year) that is required to run the compressor and pump is estimated by using the following equation (Algharaib & Al-Soof, 2008; Hendriks et al. 2004; Oldenburg, 2003):

$$E_{\text{annual}} = (W_{S\text{-total}} + W_p) \times P_e \times CF \quad (2.15)$$

where E_{annual} is the total annual electric power costs of compressor and pump [\$/yr], $W_{S\text{-total}}$ is the total combined compression power requirement for all stages [kW], P_e is the price of electricity [\$/kWh] and W_p is the pumping power requirement [kW].

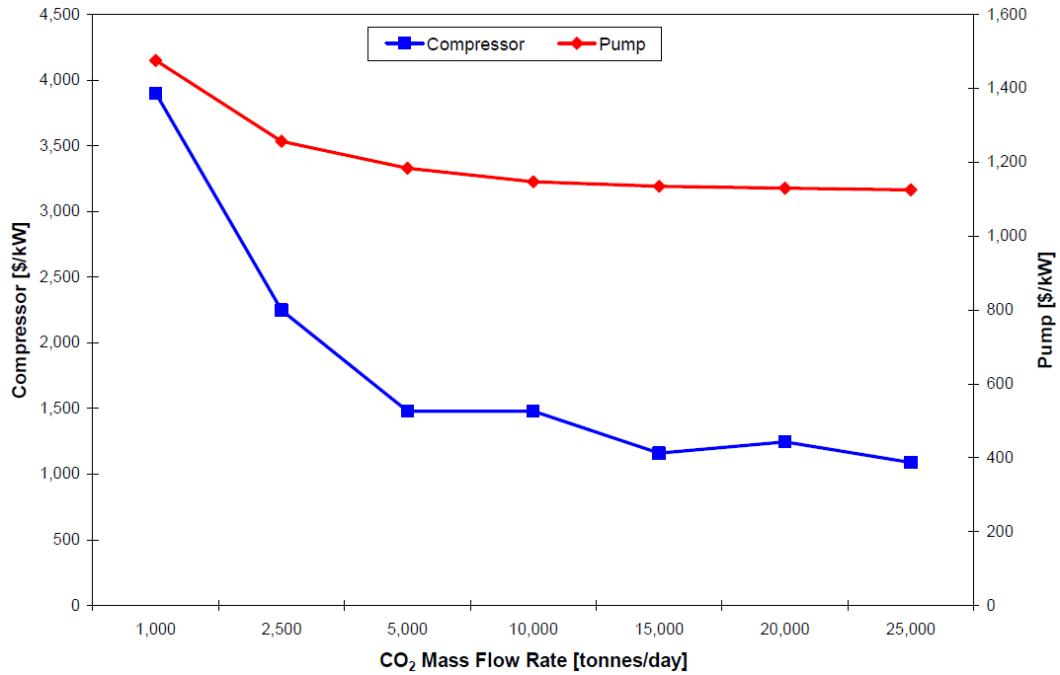


Figure 2.13: Capital costs of compressors and pumps as a function of CO₂ mass flow rate (McCollum and Ogden, 2006)

2.6.3 Carbon dioxide transport module

Few studies address the cost of carbon dioxide transport in detail. There are multiple options for transporting compressed CO₂ from the source to the geological sink. Practical modes of overland transport include motor carrier, rail, and pipeline (Mossolly, 2010). The most economic method of transport depends on the locations of capture and storage, distance from source to sink, and the quantities of CO₂ to be transported (McCoy, 2008). Accordingly, Pipelines are considered a more attractive method to transport CO₂ when compared to truck or rail. Nghia (2003) identified pipeline transport as the most practical method to move large volumes of CO₂ overland. Rubin et al., (2008) reported that there is considerable experience in the transport of CO₂ by pipeline, with up to of 50 million tonnes/ per year of CO₂ is

transported over nearly 3100 km of pipelines primarily for use in enhanced oil recovery. For large quantities of CO₂ and long distances the most economic option is transported via pipeline. However, very large distances can become a barrier for implementation of CO₂ sequestration. By contrast, trucks can be used for reduced quantities and short distances (Gusca et al. 2010).

Currently, pipeline CO₂ transportation has been adopted by most CO₂-EOR projects. In addition, recent studies also considered shipping CO₂ by modifying liquefied petroleum gas (LPG) tankers. Containers with industrial exhausted CO₂ from onshore fields are transferred to offshore fields where CO₂ is injected. It is suggested that this type of transportation is more flexible and less costly compared to that with pipeline (Nghia, 2003). During CO₂ transportation by pipelines, the separated and captured CO₂ must meet the specific physical conditions, for example it is compressed and pumped to offset the required pressure (McCollum and Ogden, 2006). Capital expenditure on the transportation system is usually related to the pipeline geometry (its diameter), specific topographical factors such as a location factor and terrain factor (Gusca et al. 2010). List of these characteristics of factors are provided in Persha et al. (2010).

Table 2.3: Terrain cost multipliers

Terrain	Cost multiplier
Flat open countryside	1
Mountainous	2.5
Desert	1.3
Forest	3
Offshore (up to 500 m water depth)	1.6
Onshore (above 500 m water depth)	2.7

Table 2.4: Regional cost multipliers (Persha et al., 2010)

Region	Cost Multiplier
Africa	0.8
Australia	1
Canada	1
Central and South America	0.8
China	0.7
Eastern Europe	0.8
CIS	0.7
India	0.7
Japan	1
Mexico	0.8
Middle East	0.9
Other Developing Countries	0.8
South Korea	0.8
USA	1
Western Europe	1

The operating and maintenance costs for transporting CO₂ are related to the mass flow rate of CO₂ and distance between the sources and sink sites. However, in practice the O&M costs are calculated by using O&M factor as a percentage of the estimated total capital cost (McCollum & Ogden, 2006; Persha et al., 2010). Estimation of the O&M factor on CO₂ pipeline transport are different for different scenarios (Table 5). Figure 14 shows the equalized cost of CO₂ transportation for 250 km as a function of mass flow rate. Unit costs of CO₂ transportation are more likely to be less when a large quantity of CO₂ mass flow rate is considered (Gusca et al., 2010).

Table 2.5: Operating costs (as percentage of capex)

Description	Annual OPEX as a % of CAPEX
Onshore Pipeline	1.5%
Offshore Pipeline	3%
Booster (onshore only)	5%

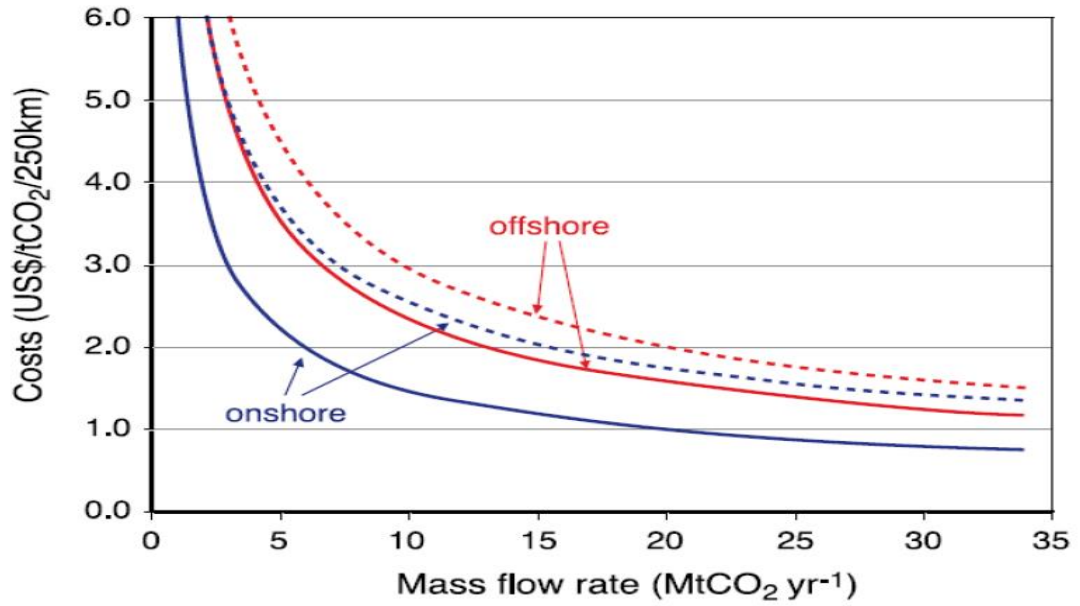


Figure 2.14: Cost for CO₂ transport via pipeline as a function of CO₂ mass flow rate (Rubin, & Berkenpas, & McCoy, 2008)

The current literature shows separate cost models by cost category, such as annualized total capital expenditure by applying capital recovery factor. In addition, the amount of CO₂ mass flow rate that need to be transported is usually annualised by using capacity factor.

McCullum and Ogden (2006) developed a CO₂ transportation cost model for capital expenditure and operating and maintenance cost components:

$$\begin{aligned}
 CAP_{trans} = & F_L \times F_T \times 10^6 \times [1.8663 + 0.057 \times L \\
 & + 0.00129 \times L \times D_{pipe} + 0.000486 \times L \times D_{pipe}^2 \\
 & + 0.000007 \times D_{pipe}^2]
 \end{aligned} \quad (2.16)$$

$$OPEX_{trans} = -260102.59 + 1734.19 \times L + 41673.43 \times D_{pipe} \quad (2.17)$$

Equation (2.18) gives the relationship between pipeline diameter (D) and maximum allowable CO₂ mass flow rate (m) as a function of the given density (ρ). where D_{pipe} is the pipeline diameter, inch, L is pipeline length, km, FL is a location factor; FT is the terrain factor, m is the optimum CO₂ mass flow rate tonne/day, and ρ is the CO₂ density kg/m³

The pipeline diameter is determined by

$$D_{pipe} = \frac{\sqrt{\frac{m}{0.5 \times \pi \times \rho}}}{0.0254} \quad (2.18)$$

Figure 2.15 plots the relationship between various CO₂ mass flow rates through different diameters of pipeline.

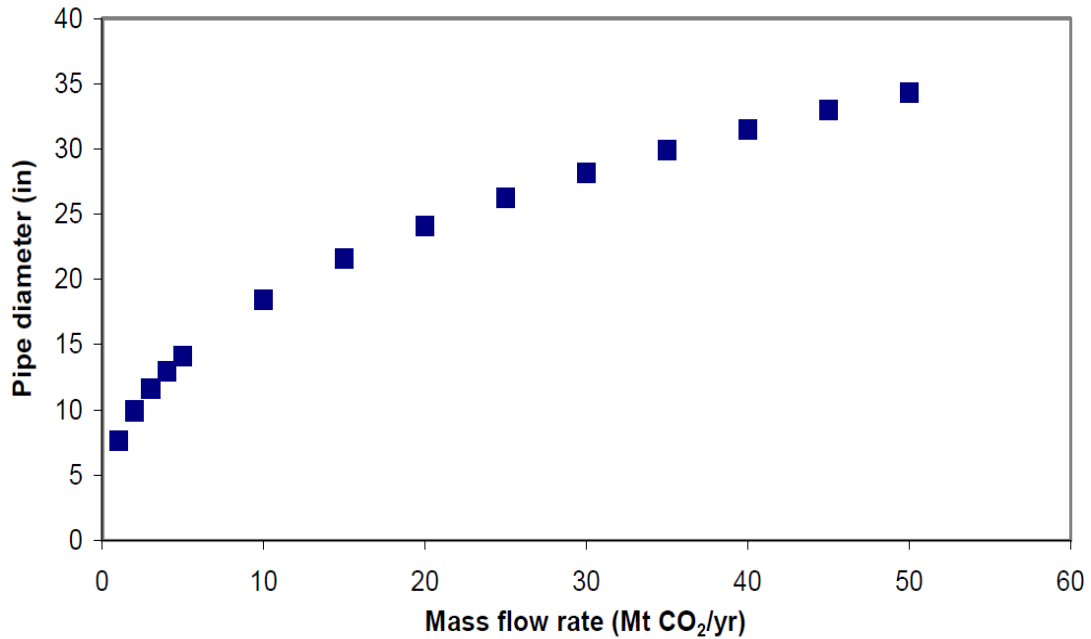


Figure 2.15: Diameter for the base case as a function of CO₂ mass flow rate (IPCC, 2005)

2.6.4 Carbon dioxide injection module

A saline aquifer is a geologic formation with sufficient porosity and permeability to transmit significant quantities of water with dissolved solids content which is referred to as “brine” or “formation water”. This formation should be of sufficient depth to ensure that injected CO₂ remains in the supercritical phase. Several studies have examined the cost of aquifer storage, in terms of the rates at which CO₂ can be injected, the storage site capacity as a function of the imposed pressure gradient and aquifer permeability. Conversely, the security of CO₂ storage with respect to leakage and the long term capacity of the aquifer are functions of fluid trapping mechanisms. Analytical engineering models have been developed for geological storage through CO₂ injection into aquifers. Cost estimations are used to evaluate the sensitivity analysis of CO₂ storage regarding to uncertainty in reservoir characteristics and other assumptions (McCoy, & Rubin, 2009). The economics model development for EOR

storage will assess the potential range of costs that could occur and the probability associated with these costs for a given scenario. In the storage process, CO₂ is received at the storage site and further compression may be required if the injection pressure is lowered during transportation. The injected CO₂ is trapped in a geological formation by physical trapping as a separate phase, soluble trapping when the injected CO₂ dissolves in the water and finally, chemical trapping where it reacts with other minerals presents in the geological formation (McCoy, 2008).

The Energy Information Administration, (1994) reported a scenario for secondary oil recovery using water flooding. The scenario was modified by Energy Information Administration, (1994) for CO₂ flooding and used by many published studies as the base for field equipment and production operation costs. Individual items of equipment have been priced by using price lists, and by communication with the manufacturer or supplier of the item in each region. In addition to cost comparisons within the petroleum industry, the reported data are often used to assess the economic effects of specific plans and policies relating to the industry (Energy Information Administration, 1994). The injection cost model consists of two types of costs, each with several components. The costs are classified as either capital or annual operating costs. Capital costs include: site evaluation and screening; drilling; and injection equipment. Annual costs include ongoing operating and maintenance costs for the injection wells. This cost model builds and extends from the original injection cost model proposed in IPCC (2005). Each of the cost components is described below (Table 2.6).

Table 2.6: Capital cost elements of wells and site evaluation (Smith et al. 2002)

Preliminary site screening	Candidate evaluation
Define screening factors	Install 10 groundwater sampling wells in USDW associated with the site
Collect documents describing candidate areas	Collect and analyse water samples from the USDW
Evaluate candidates with respect to screening factors	Install one test well in the saline aquifer
Prepare report identifying and ranking sites	Log the test well
	Collect and analyse liquid samples from the injection zone
	Collect and analyse mineral samples from the injection zone
	Perform an injectivity test in the injection zone
	Perform surface geophysical (e.g. seismic) testing
	Install geophones and perform seismic monitoring
	Perform site modelling
	Perform site seismic evaluation
	Prepare candidate evaluation report.
Costs of lease acquisition	Costs of injection equipment
Producing separator	Plant
Rest separator	Distribution lines
Heater treater	Header
Storage tanks	Electrical service
Accessory equipment	
Disposal system	
Costs of production equipment	Gathering system costs (costs of gathering system)
Tubing	Flow lines
Rods & pumps	Manifold
Pumping equipment	Gathering compressor
	Sale gas compressor

In terms of capital expenditure associated with wells, equations had been developed from a number of data sets for a single well as a function of depth dependent. The equations have constant fixed cost for site preparation and other fixed cost items. Variable costs increase with depth. All cost documentations were originally based on the 2001 Joint Association Survey (JAS) cost study, and have recently been updated and published by API Advanced Resources International for various regions in US. In addition, McCoy, & Rubin (2009) have adopted some of these equations and updated them based on the required number of wells as a function of a given depth of the well

$$C = a_1 e^{a_2 d} \tag{2.19}$$

$$C = a_1 d^{a_2} \tag{2.20}$$

In Equations 2.19 and 2.20, C is the component capital cost, d is the reservoir depth in meters, and a1 and a2 are regression coefficients.

Table 2.7: Capital cost categories for different regions in U.S (McCoy and Rubin, 2009)

	Drilling & Completion		Production Well Equipment	
	Exponential		Power	
	a ₁	a ₂	a ₁	a ₂
W-TX	\$122,555	8.04×10 ⁻⁴	\$61	9.75×10 ⁻¹
S-TX	\$136,434	8.04×10 ⁻⁴	\$4,681	3.04×10 ⁻¹
S-LA	\$190,790	8.04×10 ⁻⁴	\$3539	3.47×10 ⁻¹
MCR	\$110,907	8.04×10 ⁻⁴	\$888	5.74×10 ⁻¹
RMR	\$178,547	8.04×10 ⁻⁴	\$36	1.02×10 ⁰
CA	\$165,290	8.04×10 ⁻⁴	\$9,214	2.58×10 ⁻¹
AK	\$531,697	8.04×10 ⁻⁴	\$9,214	2.58×10 ⁻¹
APPL	\$88,263	8.04×10 ⁻⁴	\$888	5.74×10 ⁻¹
OTHR	\$110,907	8.04×10 ⁻⁴	\$888	5.74×10 ⁻¹
	Less Equipment		Injection well Equipment	
	Power		Exponential	
	a ₁	a ₂	a ₁	a ₂
W-TX	\$36,749	2.99×10 ⁻²	\$31,226	2.81×10 ⁻⁴
S-TX	\$4,207	3.83×10 ⁻¹	\$37,040	1.16×10 ⁻⁴
S-LA	\$5,803	3.54×10 ⁻¹	\$39,876	1.13×10 ⁻⁴
MCR	\$11,413	2.10×10 ⁻¹	\$39,876	1.13×10 ⁻⁴
RMR	\$23,801	1.35×10 ⁻¹	\$29,611	2.60×10 ⁻⁴
CA	\$56,711	6.70×10 ⁻²	\$38,931	2.10×10 ⁻⁴
AK	\$56,711	6.70×10 ⁻²	\$38,931	2.10×10 ⁻⁴
APPL	\$11,413	2.10×10 ⁻¹	\$39,876	1.13×10 ⁻⁴
OTHR	\$11,413	2.10×10 ⁻¹	\$39,876	1.13×10 ⁻⁴

The IPCC (2005) developed equations regarding to the Operating and Maintenance (O&M) costs associated with well drilling. The costs data are all based on data originally produced by Energy Information Administration. Average cost values are adjusted to take into account number of wells and the well depth. These activities include (see Table 2.8):

Table 2.8: Operating and maintenance costs of wells drilling

Operating and maintenance Costs (O&M)	
Normal daily expenses	Supervision & overhead Labour Consumables Operative supplies Pumping & field power
Normal Daily Expenses \$/well	number of well × 6,700
Consumables \$/well	number of well × 17,900
Surface maintenance (repair and services)	Labour Supplies and services Equipment usage Other
Surface Maintenance (Repair & Services) \$/well	$13,600 \times (7,389 / (280 \times \text{Number_of_wells}))^{0.5}$
Subsurface maintenance (repair and services)	Work over rig services Remedial services Equipment repair Other
Subsurface Maintenance (repair & services) \$/well	$5,000 \times \text{Well_depth} / 1219$

2.7 Greenhouse gas emissions under the Kyoto Protocol

The Kyoto Protocol is the first international agreement on emissions of greenhouse gases (GHG) that contains obvious emission limits and timetables. In the Protocol, a group of industrialized countries have agreed to stabilize or reduce GHG emissions in the commitment timetable (Springer, 2003). Global energy related to emissions of carbon dioxide is projected to grow at rate slightly higher than primary energy demand that is at 1.8% per year from 2006-07 to 2030. This creates a long-term energy and environmental policy challenges to provide affordable energy for economic and social development, whilst on the other hand limiting the long-term growth in greenhouse gas emission and associated atmospheric concentrations to the extent that may prove necessary (Giri, & Giri, 2008). Recently, the Kyoto Protocol imposes certain restrictions on developed countries. Developed countries are committed to reduce greenhouse gas emissions to 1990 levels by establishing national greenhouse gas emissions reduction programs. The range of necessary carbon emission reduction distributed as 8% reductions for the European Union to 7% for the US (the US remained out of the agreement), 6% for Japan, 0% for Russia, and permitted increases of 8% for Australia and 10% for Iceland. Developing countries have no limits, including China and India (Deatherage & Thompson, 2008).

In response to concerns about global climate change, the European Union has imposed mandatory constraints on carbon dioxide emissions from thousands of industrial facilities across Europe such as United Kingdom and Netherlands. Recently, Japan is also intended to develop market based instruments for the purposes of emission reduction and join the Kyoto Protocol regulation (Mingst et al. 2006). In addition, there is some suggestion that the proposed emission trading scheme in Canada and United States are proposing to accept the Clean Development and Mechanism (CDM). Clearly, China and India will be considered for the majority of future increase in greenhouse gas emissions in the developing countries (Talberg & Nielson, 2009).

In the developed countries, the US is another emitter and has not yet submitted to the Kyoto Protocol agreement. Thus, it is presenting a challenge to contribute and reduce current and future emissions without participation of these countries in the process. While, under the rule of Clean Development and Mechanism, developing countries

such as China and India are feasible candidates for developed countries in order to project in these two countries to meet the reduction commitment and their pollution right can be sold to the industrialisation countries to offset emissions in other places such as the US and Europe (Deatherage & Thompson, 2008).

Since 2010 greenhouse gas emission trading has been proposed to begin in Australia. International implementation of this concept will force carbon polluting companies to emissions permits equal to the value of their emissions by undertaking GHG emission reduction projects. Combination of the countries already registered to the agreement by Kyoto Protocol and the other countries proposed national emissions trading scheme, together potentially are promising various carbon trading schemes in emerging global markets (Talberg & Nielson, 2009).

2.7.1 Greenhouse gas emission challenges and opportunities for industry

Excessive CO₂ emission in the atmosphere due to consumption of fossil fuels is expected to rise. Consequently, there are risks of anthropogenic global warming which has fatale costs. Consideration of efficient use of energy is helpful. While, reduction in atmospheric CO₂ requires carbon sequestration methods; currently carbon capture and sequestration is the most discussed method of sequestration (Gupta, 2009). The Kyoto Protocol of the United Nation Framework Convention on Climate change established that developed countries individually or jointly would have to reduce at least an average of 25% below the emissions level in 1990; during the period 2008-2012. In addition, the developing countries have not obligation to reduce greenhouse gases (Gallo et al. 2002).

The full arrangements, flexibility and use of international mechanisms regarding the greenhouse gas emission that have been proposed by the Kyoto Protocol are summarised as; (Mingst et al. 2006).

- Clean Development Mechanism (CDM)
- Joint Implementation (JI)
- Emission Trading Scheme (ETS)

Theses mechanisms economically provide market based solutions to reduce greenhouse gas emissions. JI and ETS are exclusively directed to developed countries. Countries may buy and sell the amount of emissions among themselves

that establish the limits of the “right to pollute”. The CDM is the right of a developed country to undertake projects in the developing countries to reduce emission commitments from the atmosphere and to meet emission reduction target. In addition, the excess allowances can be sold to industrialized countries (Gaspar et al. 2005).

Under the Kyoto Protocol, CCS is a candidate to reduce greenhouse gas emission. The technology for CCS already exists as commercial scale application in the context of enhanced hydrocarbon recovery. Therefore, early successes with limited number of CO₂ storage and long-time of experience with enhanced oil recovery have provided confidence that long term storage is possible in appropriate selected geological storage reservoir (Benson, 2006). When the projects of enhanced hydrocarbon recovery are eligible for carbon credit scheme as a part of deployment of CCS process, Commercially, CCS is likely to be more feasible regarding to enhanced hydrocarbon production and certainly reduced CO₂ concentration in the atmosphere if the carbon credit markets come into existence in any significant way.

A carbon credit is defined as reduction of 1 t CO of fossil emissions by either preventing it from atmosphere or by extracting it out of atmosphere (Gupta, 2009). Under the Kyoto Protocol mechanisms CDM, IJ ETS, to date, there are no CCS projects approved under these regulations. The current CCS technology despite of its expensive cost, in terms of storage, has still some unresolved issues associated with operation and long terms liability of CCS implementation. For example the uncertainty of the application of carbon credit if the injected CO₂ leaks back into the atmosphere. Another issue is who will take the responsibility for the below listed liabilities (Gupta, 2010; Gupta, 2009):

- (a) legal liability for leaks through wells and for leaks through fractures and fissures;
- (b) liability for remediation;
- (c) liability for environmental damage (e.g., soils, groundwater, surface ecosystems) due to leaks;
- (d) liability for damage to wells and mineral resources;
- (e) liability to compensate individuals for damage to property and/or persons as a result of a leak; and

- (f) Responsibility of Monitoring, measurement and verification (MMV) of movement of CO₂ plume and maintenance of records for future generations.

2.7.2 Key risks posed by the introduction of carbon credit scheme

Where Kyoto Protocol regulations are implemented, the risks for operations are determined by the emission restriction. In the European Nation regulations, during the selected periods 2005-2007, to 2008, expectation of the penalty for non-agreement was €40 per tonne and increased to €100, respectively (Mingst et al. 2006). The purpose of implementation of the CO₂ penalty regime is to provide incentives emission reduction otherwise disposal greenhouse gas emission might never be achieved. Application of CCS on a wide scale is likely to take place in the context of a carbon trading regime or with development of low emission reductions portfolio standards. In addition, sequestration of carbon regarding to carbon emission reduction need to carry a recognized value or carbon credit (Benson, 2006).

No official standard methods have been developed to estimated carbon credit value, although carbon trading system has been emerging worldwide. (Steffen, & Asbjorn, 2009) claimed that future estimation of carbon credit price is a difficult task. The estimation is straightforwardly in tune through the policy assumptions, the target of the GHG reduction and the type of mitigation candidate. Because current literature studies show large variations in price, based on combined results from 25 models under Kyoto Protocol regulations Springer (2003) estimated carbon price and ranged from 1 to 22 US\$.

Additional risks also exist particularly under CDM regulations. Some industrialized countries are establishing projects in developing countries and present significant risks that projects may not be confirmed or registered, and the credit may be issued in whole or part, for example when the developed countries agree to buy the Certified Emission Reduction before the projects have been approved (Giri, & Giri, 2008). Under this scenario, company's face four types of risks; generally consisting of the following;

- (a) Political and country risk;
- (b) Project risk;
- (c) Regulatory risk; and
- (d) Post Kyoto risk.

Deatherage & Thompson (2008) state that if these types of risk are in control by the seller the price is expected to be high, while, the price is expected to be lower when these risks are shifted from seller to buyer. Long and short terms are considered by oil and gas companies to develop climate change strategy as part of changes in production, marketing in fossil fuels and economic opportunity in order to cost-effectively monetize the proposed greenhouse gas emission reduction if any restrictions are imposed.

2.8 Conclusion

This chapter has presented a critical review of current literature relevant to research findings. Thermodynamically, it discusses the theme of natural gas reservoirs with emphasis on their characteristics under different conditions where CO₂-EGR and storage is considered. In addition, it covers analysis of the costs elements involved in the process of CO₂ capture and storage. Each cost components and their modules implementations were also described separately. Furthermore, an introduction on carbon credit concept was presented and its feasibility effects on such a project (CO₂-EGR). All these concepts are argued and compared with the findings of this research work in the following three chapters.

Chapter Three

Experimental Study

3.1 Introduction

This chapter presents the experimental procedures and equipment setup for the interfacial tension and core-flooding experiments. The processes were noted to be dependent upon pressure, temperature and gas composition. The interfacial tension was formed to be strongly influenced by the injecting flow velocity or displacement velocity. The experiments were carried out at various temperatures, pressures and flow rates (see Table 3.1). This chapter also describes relative permeability of CO₂-methane and CO₂ displacement efficiency injection into gas reservoir as a function of fluid viscosity, pressure drop, and permeability.

The results from the relative permeability suggested that even though the two phases of CO₂ and methane are miscible; their relative permeability shapes noticeably can be affected by the morphology of the porous medium. The purpose of this chapter is mainly a preparation of relative permeability of CO₂ and methane for the reservoir simulation model in the next chapter, to investigate the feasibility of CO₂-EGR and storage under various conditions.

3.2 Experimental set up

The experimental procedures and equipment are setup for the interfacial tension and core-flooding experiments are explained. The main necessary constituents of the experimental setup consist of pressure transducers, back pressure-regulator, flow meters, air bath temperature control and CO₂ analyser, a high-pressure chamber with two visual observation windows used to monitor and record inside the cell. During the experimental, the temperature was maintained by the climatic air. The pressure cell was positioned exclusively within the air bath. The scheme of injection system is made up of two components as a syringe pump and two titanium cylinders. Each of these two components was attached to a piston for the purpose of boosting pressure

in the system. There are three ports around the pressure chamber and supervised via very fine metering valves. In this experimental investigation, the upper and lower ports are organised as a port located at the bottom, which was utilised as a means of accomplishing a purpose of introduction of the supercritical CO_2 into the methane phase. In addition, the port placed at the top was used as a means of achieving a pressure monitoring point.

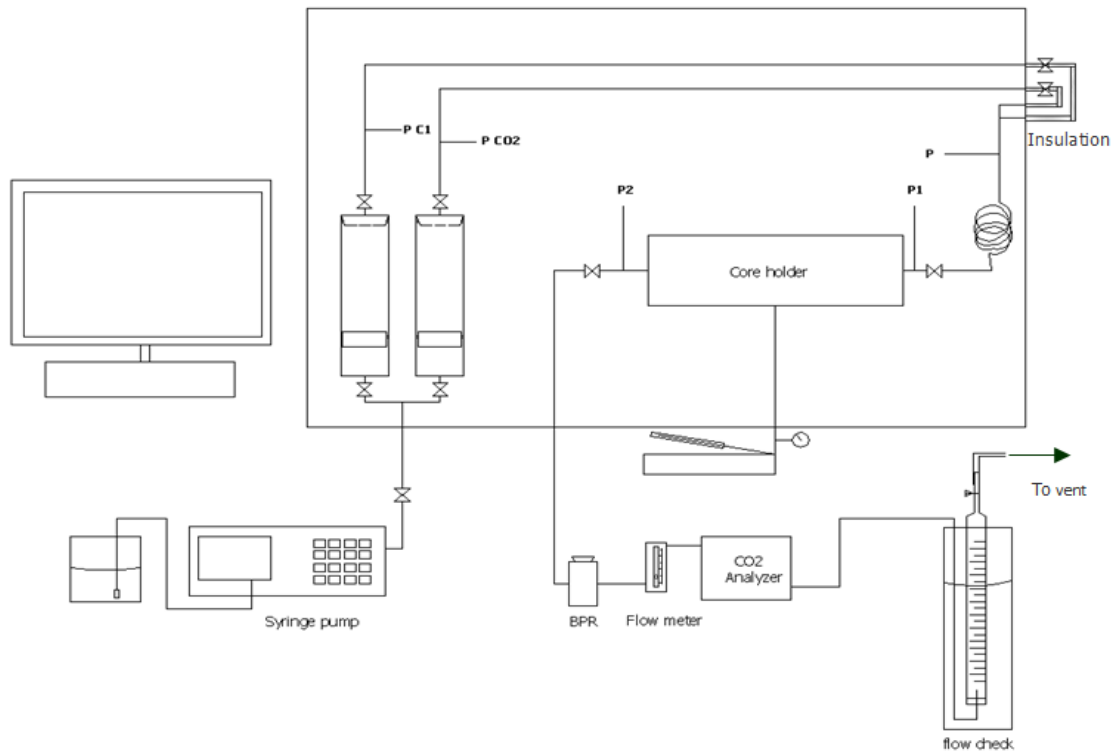


Figure 3.1(a): Diagram of the experiment apparatus

In a state of achieving proper high resolution images of supercritical CO_2 drop, the observation see-through was characterised by a windowed high-pressure chamber and it was located between a light source and a microscope digital camera with the entire experimental set up was installed on a stabilised table free of vibrations. When the supercritical CO_2 was introduced from the bottom port, it resulted in forming a drop in the methane phase at the top-end of a stainless-steel capillary needle. Observation of the process of CO_2 drop image was performed through endoscope connected to computer recording system, for capturing, analysis, digitization, and computation. In general, the entire procedures were observed continuously and stored in a temporary memory in the data taker. After the stage of finishing the test, the produced data was downloaded directly into the computer. Overall, this

experimental system initially had been set up and investigates the interfacial interaction in a way where supercritical CO₂ and methane are considered at high pressure and temperature conditions.



Figure 3.1(b): Modified sketch of experimental apparatus designed to stand up to 160 °C and 6000 psia

The, experiments were run at different pressure and temperature conditions as shown in Table 1. During the investigation of these conditions due to sates of super critical CO₂ especially at the last condition, some of the components involved in building up the system had to be replaced such as tubes, back pressure regulators and valves.

Table 3.1: Pressure and temperature variation for core flooding system (Sidiq 2010)

Condition	Pressure (psia)	Temperature (°C)
1	3000	95
2	6000	95
3	590	160

3.3 Interfacial tension measurement

In this section, the existence of immiscible interface between supercritical CO₂ and methane is investigated. No previous studies have been published to illustrate the potential of CO₂ to form an interface with other gases (Amin et al., 2010). For the first attempt to measure the interfacial tension between supercritical CO₂ and methane was investigated by Clean Gas Technology Australia at different pressure and temperature conditions. The experimental results indicated that the experimental challenge of supercritical CO₂ and methane interfacial tension measurement is making the initial stable interface ready prior to mixture contamination with injecting supercritical CO₂. Because the concentration of the gas mixture is changed with time and will results in changing the interfacial tension by means of dispersion. Therefore, the interface between the supercritical CO₂ and methane need to be visibly clarified in order to manage the mixing process accurately. Accordingly, this task was anticipated to be pressure, temperature and composition dependant but, it was noticed that the distinguished of interface between the gases was more sensitive to the injection rates. With this regard, CO₂ was located on the bottom in contact with methane on top. As a result, the interface was controlled by the velocity of CO₂ flow as a function of pressure and temperature of 1200 psia and 95 °C up to 6000 psia and 160 °C, respectively (Figure 3.2) (Sidiq 2010).

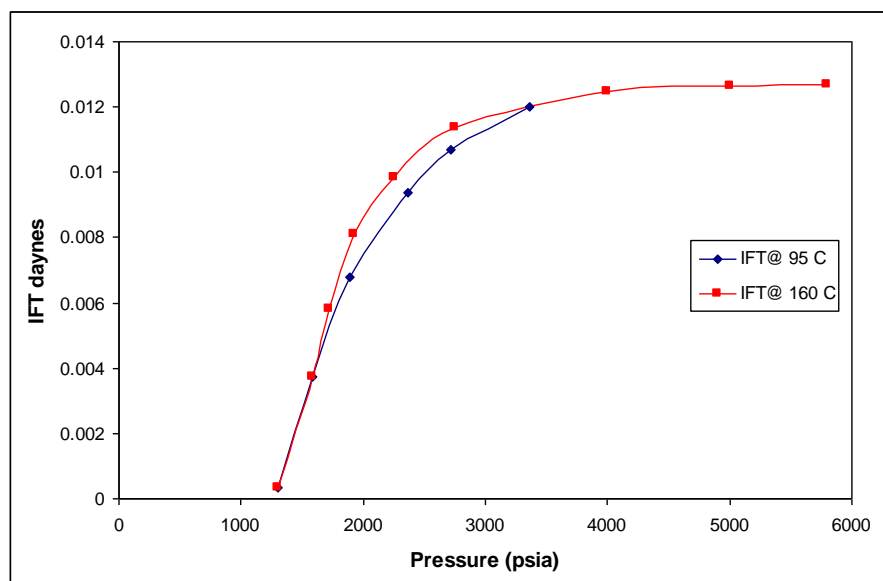


Figure 3.2: CO₂-Methane interfacial tensions (IFT) as a function of pressure and temperature

In terms of injection rate, the mixture in the system was controlled and limited at low injection rate via controlling the micro-meter valve and also due to the favourable CO₂ density compared to that for methane. Consequently, supercritical CO₂ was anticipated to migrate downward due to gravity effects and mixing with methane only at the interface with methane (Figure 3.3). At the capillary needle, methane was anticipated to be moved upward and producing a visible interface. In addition, the continuation of CO₂ injection led to reduce the visibility level of the interface. As a result, it was eventually disappeared due to dispersion and molecular diffusion.

For interfacial tension measurement, during the process of CO₂ injection via the capillary needle the gas bubble is created at top end of the needle as a function pressure for a given supercritical CO₂ injection. The image of the gas bubble at the tip of the stainless-steel needle was measured with respect of area, width, length, perimeter and contact-angle (see Figure 3.4). From Figure 3.4, the formed gas bubble which represents three phases supercritical CO₂, methane gas and solid and it is divided into two parts, as a horizontal interface and then an arched shape is formed. This shows a zero angle contact of gases-solid phases and points out that there is no existence surface tension due to undistinguished of the interface with the solid phase. Thus, the boundary of the arched shape represents methane-solid surface tension and below the arched line shows supercritical CO₂- solid surface tension. In terms of value, the difference between these two scenarios is smaller than the surface tension of supercritical CO₂-methane due to zero angle contact between gases-solid phases.

Figure 3.2 shows interfacial tension as a function of pressure for given temperatures. The results demonstrate almost the same trends of the interfacial tension measurements. Under both temperature conditions the interfacial tension measurement impressively increased from the pressure of 1300 psia up to 3000 psia in addition to a slight increase for the interfacial tension at pressure of 5800 psia under the case of 160 °C. In addition, interface at higher injection rates for the given pressures from 5000 psia, slowly begins to decline. The reason is that, supercritical CO₂ overrun methane as a function of its diffusion with respect of injection time. The experimental results indicated that contamination by supercritical CO₂ is potentially higher under low injection compare to that under high injection as a function of molecular diffusion. Under higher injection rates, the interface of supercritical CO₂ was observed to be more attractive. However, during reduction in CO₂ injection rates the supercritical CO₂ has already been injected instantly starts to mix and spread

around the formed shape on the tip needle. As a result, the interfacial tension between the fluids is reduced and the front of the gas bubble becomes more miscible. However, molecular diffusion and dispersion depend on the flow direction, in the reservoir this phenomenon depends on the permeability heterogeneity rather than inter-molecular forces of diffusion.

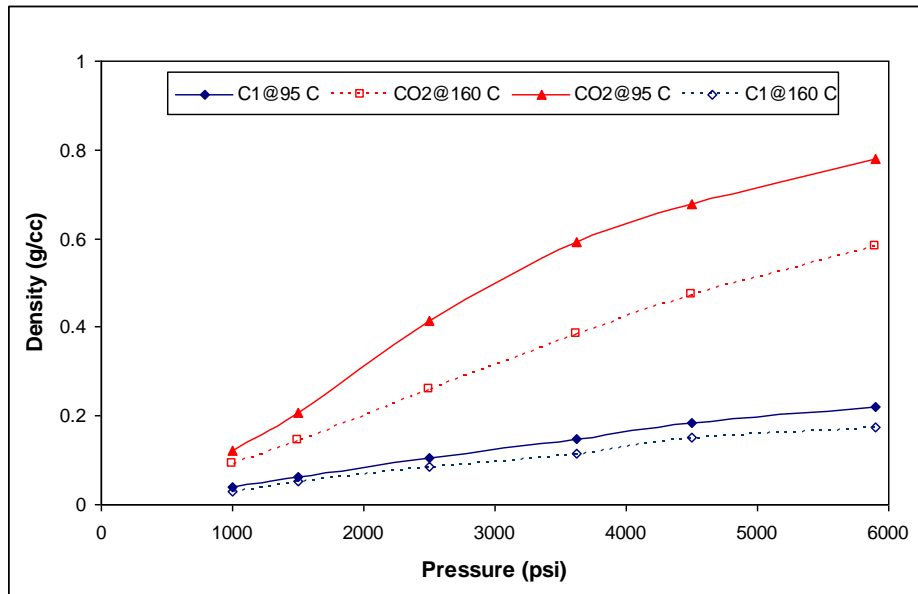


Figure 3.3: CO₂-Methane densities at various temperatures and pressures

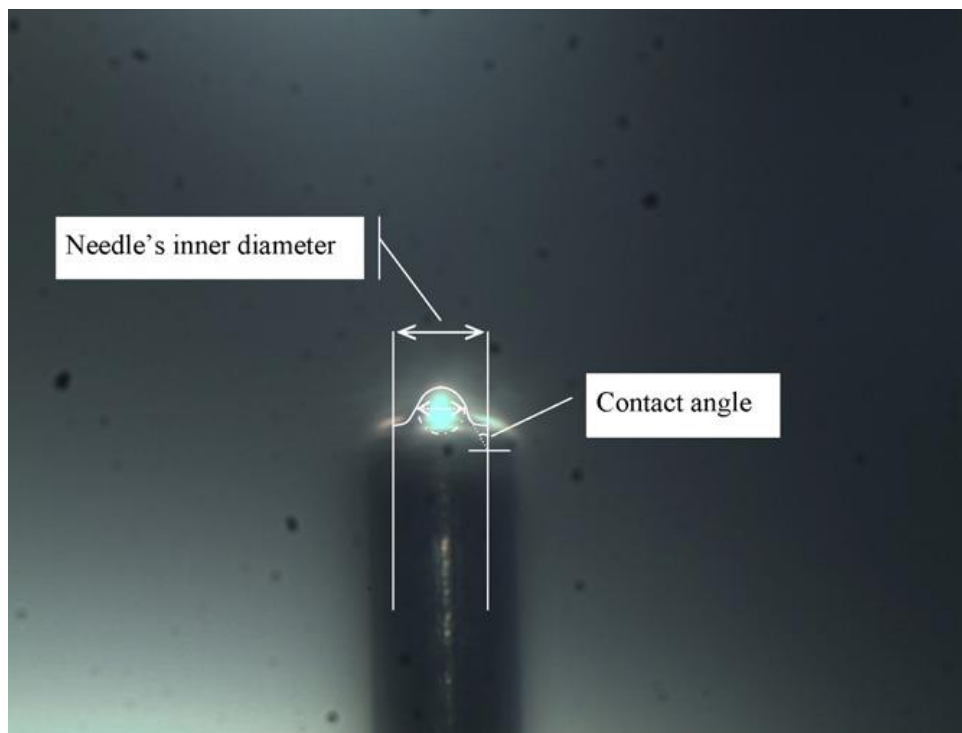


Figure 3.4: Schematic illustrating the dimensions used in IFT measurements. The ambient is methane and the bubble on the tip of needle is CO₂

3.4 Core flooding procedure

The particular order in which related to the core flooding procedure is started by fitting the core plug samples into a Viton Hassler sleeve and put inside the core holder. The temperature of the air bath was boosted to the required conditions and the pore pressure was supervised depending on the back pressure in the system. At the stage when equilibrium condition was reached, the inserted core plugs were flushed nearly for 10 pore volumes up to 100% brine saturation achievement in the core plug samples so as to be ready for the next steps. Then, the brine was displaced by 90% of methane and 10% of CO₂ to irreducible water saturation. Subsequently, the procedure was aged overnight. As a result, effective gas permeability at the irreducible water saturation was estimated. At the end, methane was displaced by CO₂ at of pore pressure of 5900 psia and 7500 psia as an overburden pressure as a function of the given injection rate. In this way, the relative permeability of supercritical CO₂ could be calculated from the unsteady state displacement tests for all the core plugs. Constantly, the content of the produced gas was observed through a supercritical CO₂ gas analyser and the observation results stored on an integrator. Measurement of the gas production was performed through the flow meters that were connected in series. Consequently, the recovery of methane at supercritical CO₂ breakthrough was estimated.

3.5 Relative permeability calculation

In this section relative permeability concepts of methane and supercritical CO₂ are performed due to its importance roles in the displacement process. Steady state tests were investigated for four different core plugs at pressure and temperature of 5900 psia and 160 °C, respectively with a constant velocity of 10 cm/hr. In addition, relative permeability of supercritical CO₂ to methane was measured after approximately 10 pore-volumes of injection and the pressure drop across the core and CO₂ percentage at the outlet continuously was kept under observation. In the beginning of the procedure, the originally the core plug was saturated with methane and investigations started by injecting supercritical CO₂ slowly into the core plug at various percentages as 10, 20, 50 and 75% of CO₂ content. Unsteady state displacement tests were performed to estimate end points relative permeability, once the outlet composition was reached to around 98% of CO₂ concentration in the

effluent stream with achieving stable pressure difference across the core samples. To calculate permeability from experimental data, three short core samples with one long core plug were used for CO₂-methane core flood experiments. The core plug samples have different petro-physical characteristics as mention in Table 3.2. Accordingly, for this purpose the modified Darcy are used to obtain K in (md):

$$K = 14700.Q.\mu.(L/ A)/(\Delta p.60) \quad (3.1)$$

where K is permeability to liquid, md, L is sample length, cm, Q is the flow rate, cm³ per min, Δp is the pressure difference across the core sample, atmospheres, μ is viscosity, centipoise, and A is a cross sectional area, cm².

Effective permeability for any phase is calculated when Δp across the core sample stabilized at the end of the run and the effluent composition approach influent composition.

Consequently, the relative permeability of supercritical CO₂ and methane phases from each test are calculated by dividing its phase relative permeability at each subsequent percentage to its effective permeability during steady state tests when each CO₂ and methane of the effluent are contained 98% and 90%, respectively. This practice was for the purpose of calculating relative permeability curves. As a result of the experiment, the supercritical CO₂ end points permeability noticed to be bigger than that was for methane under all the different core plugs investigation. It was anticipated that these differences between end points permeability resulted due to stripping connate water and also the influences of rock heterogeneity makes CO₂ to channel through the core plug samples to their outlets.

Table 3.2: Endpoint relative permeability calculated from 90C₁ displacement by SCO₂ at 160 °C and 5900 psia (Sidiq 2010)

Samples	L	A	Δp (psi)	Flow rate		Speed cm/hr	Visc (cp)	Kg (md)	B.T (Pv)
				Reservoir (cc/min)	Ambient (cc/min)				
S_C_1A	5	12.25	5	0.341	98	9.6	0.0497	97.4	4.8
S_C_2A	5.05	11.89	6.6	0.272	86	9.2	0.0497	67.4	5.4
S_C_3A	5.1	12.01	9.1	0.201	58	9.4	0.0497	32.9	0.62
S_V_1	19.41	11.95	5.8	0.265	79	9.1	0.0497	270	7.2

3.6 Steady state relative permeability curves for core plug samples (Sidiq 2010)

3.6.1 Sample S-V-1

Relative permeability is a multiplier (between 0 and 1) of intrinsic permeability which describes the relative ease of flow of two competing fluids, such as CO₂ and methane, through a porous medium. In this case the relative permeability of SCO₂ and methane can only be proportional with the saturation in the rock pores. Because both fluids are injected simultaneously, the partial mixing of supercritical CO₂ and methane at the core inlet is almost certain, once a stable flow is attained. Mixing will start to take place and continue over a longer time scale (10 PV) by molecular diffusion. However, diffusive mixing of supercritical CO₂ and methane can give rise to compositional gradients that can induce some saturation distribution variation of an individual flow path. Understanding this coupled response of diffusion and flow to concentration gradients is important for predicting mixing times in stratified gas reservoirs that are used for supercritical CO₂ sequestration. Figure 3.5 shows pressure drop versus injected pore volume for the flowing phases through sample S_V_1. The effluent was composed of about 22% supercritical CO₂ with 78%, after injecting 5 pore volumes. Steady-state relative permeability was calculated for this percentage when the composition and pressure drop was stabilized after injecting 5 pore volumes. For example, only one point of relative permeability can be generated from this steady state experiment when the saturation of CO₂ reached approximately 20% in the core plug (see Figure 3.6).

Figure 3.5 the pressure drop versus injected pore volume from the simultaneous injection of supercritical CO₂-methane through S_V_1 at 160 °C, 5900 psia and 10 cm/hr. supercritical CO₂ concentration 20%.

Figure 3.6 shows relative permeability curves for sample S_V_1 that are produced from the steady state experiments. When the saturation of supercritical CO₂ in the core was increased to 50% its relative permeability was dramatically increased. This indicated total miscibility had been reached. Such change can cause the formation of new flow pathways for each phase. This hypothesis is supported by the fact that the pathways may not have been accessible initially because of trapped methane.

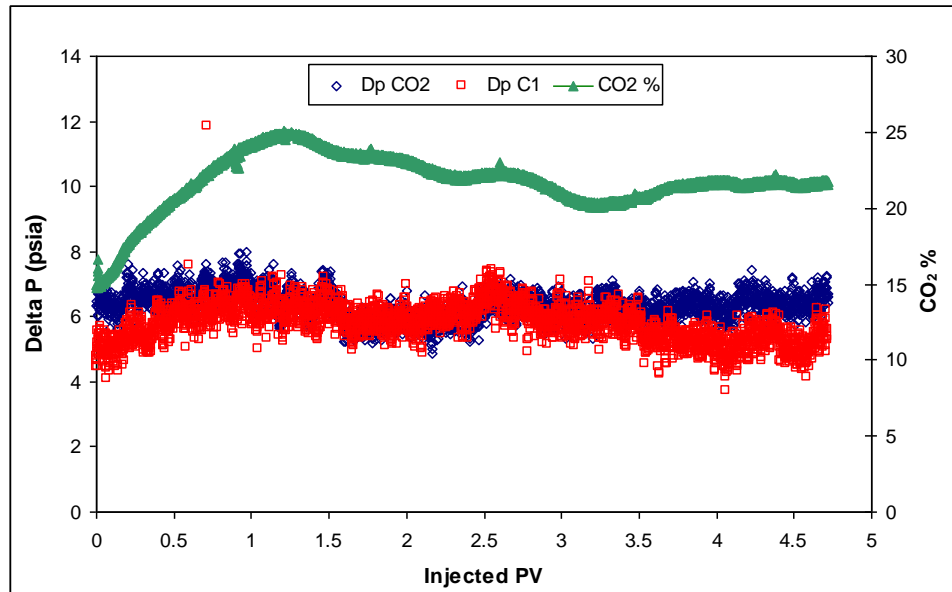


Figure 3.5: Pressure drop versus injected pore volume from the simultaneous injection of supercritical CO₂-methane through S_V_1 at 160 OC, 5900 psia and 10 cm/hr. SCO₂ concentration 20%

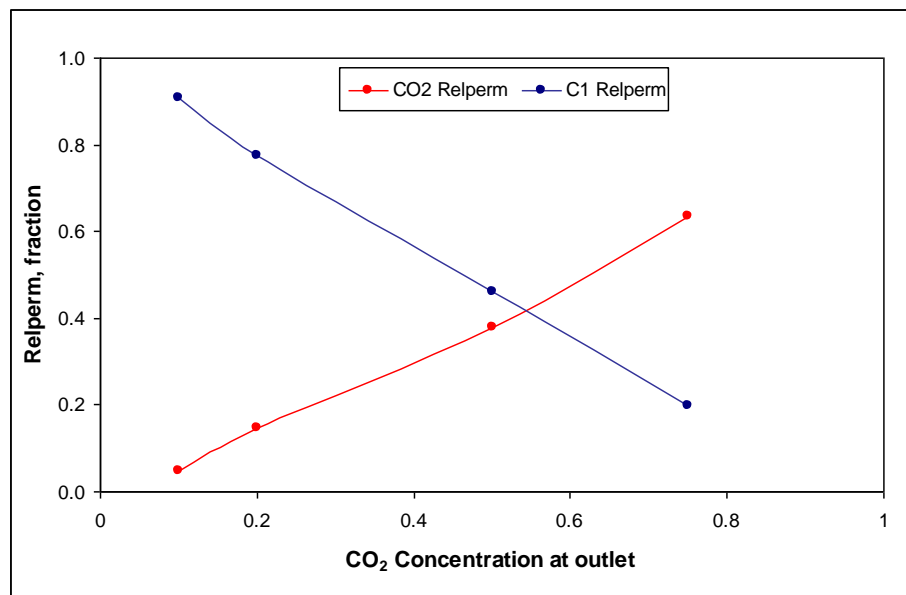


Figure 3.6: Steady state relative permeability of sample S_V_1

As the CO₂ concentration is increased to become 75% (methane comprised 25%) of the effluent gas, the relative permeability of CO₂ was enhanced noticeably. Accordingly methane recovery would not be expected to be greater than 0.7 PV of the original gas in the sample S_V_1. With steady state tests, the more viscous and

denser phase will result in greater pressure drop across the core. Subsequently, poor relative permeability outcomes are reported. This is why supercritical CO₂ has demonstrated lower relative permeability in steady state tests. Enhanced relative permeability with methane in steady state is an indication of the fact that methane had a greater momentum with continuous injection at a constant ratio. Hence supercritical CO₂ cannot obscure methane fractional flow, and relative permeability of the medium will depend mainly on the measured pressure drop.

Miscibility will increase with the time due to molecular diffusion, which results in a flowing phase representing a compositional gradient. With continual injection, each phase was barely able to form a different flow path through the medium. Accordingly, the displacement relative permeability represents the gas multiphase flow in porous media rather than simultaneous phase flow.

3.6.2 Sample S_C_1A

Results of the steady-state test of sample S_C_1A is shown in Figure 3.7. The curves display almost the same pattern as the steady state curves that were achieved with sample S_V_1. The key differences of the steady state curves of sample S_C_1A from other samples is that relative permeability of supercritical CO₂ intercepted the methane relative permeability curve at a lower saturation of supercritical CO₂ than for the other samples. This behaviour was noticed in the displacement tests in which supercritical CO₂ had earlier breakthrough with sample S_C_1A than the other core samples. By increasing the absolute permeability of the medium, a low capillarity regime is expected. Obviously in the displacement tests, with increasing absolute permeability, supercritical CO₂ had earlier breakthrough by 15% when compared to the breakthrough obtained with low quality rock S_C_3A. The disproportional relation between breakthrough and absolute permeability of the core plugs can be interpreted precisely through the pore morphology and size of the rocks. Since the wettability of the medium can only marginally affect the propagation of the gas flow, pore size, and its distribution in the medium will be considered to have significantly impacted the gases multiphase flow.

3.6.3 Samples S_C_2A and S_C_3A

The steady-state relative permeability curves of the core samples S_C_2A and S_C_3A are shown in Figures 3.8 and 3.9 respectively. For these cases the relative

permeability curves experience similar characteristics. The difference can be seen as the SCO₂ relative permeability of sample S_C_3A advanced the methane relative permeability at greater saturation in comparison to intermediate rock quality S_C_2A. This has confirmed the above assumption, that high permeable rock is accompanied by a high capillarity regime and that larger pore distribution is abundant in the core plug. In this way, dissipation of the miscible zone occurred and resulted in accelerated mixing by a molecular diffusion mechanism that led to earlier SCO₂ breakthrough. Again, permeability heterogeneity had heavily impacted the multiphase flow of the gas in the porous medium.

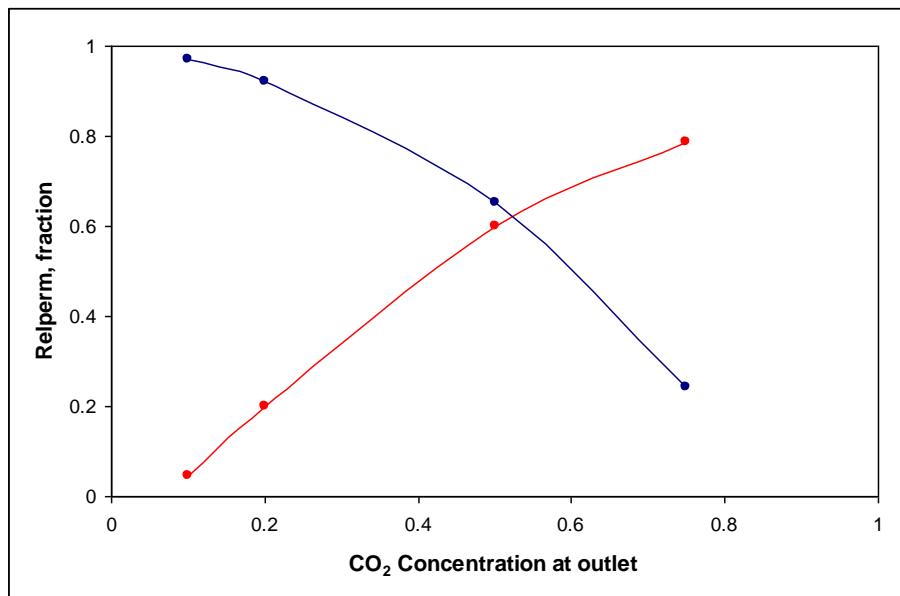


Figure 3.7: Steady state relative permeability of sample S_V_1A

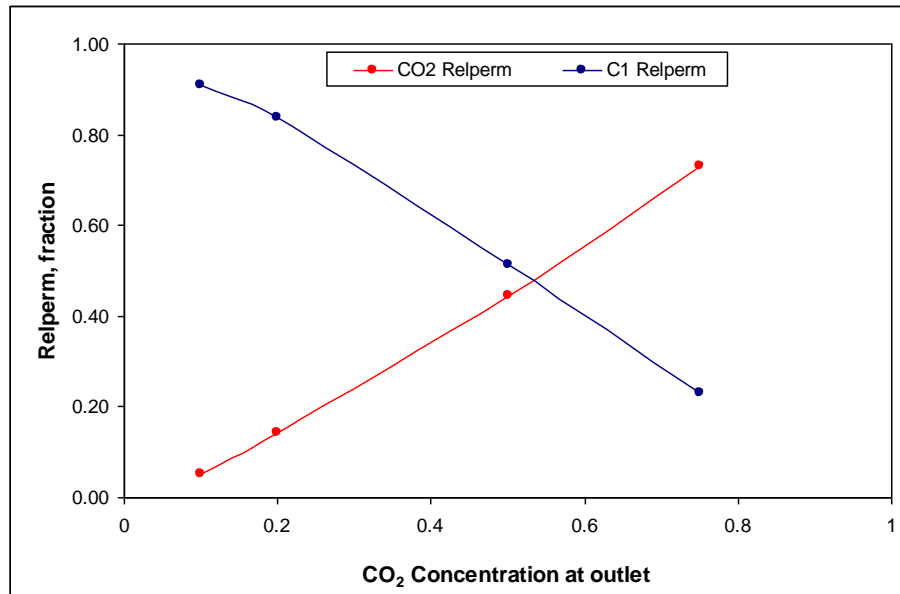


Figure 3.8: Steady state relative permeability curves of sample S_C_2A

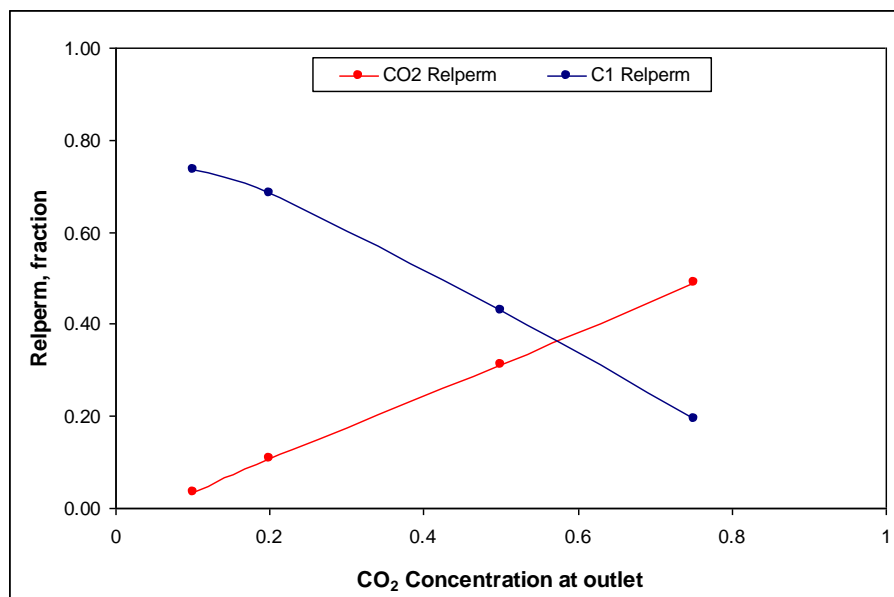


Figure 3.9: Steady state relative permeability curves of sample S_C_3A

3.7 Discussion of the results

(Although, the relative permeability plays the main role in the recovery scenario; there are also other parameters that affect gas production such as petro-physical characterization, gravitational effects, gas phase behavior, and mass transfer by molecular diffusion and dispersion processes (Jerauld 1997). Sidiq and Amin, (2012) indicated that the fractional flows and molecular diffusion determine methane/CO₂

production ratio, breakthrough timing, and the incremental and ultimate recovery. In return this could lead to dissipation of the miscible fluid through heterogeneity and resulting early breakthrough (Sidiq and Amin, 2009). Recent research studies suggested that even though the two phases of CO₂ and methane are miscible; their relative permeability noticeably can be affected by the morphology of the porous medium (Amin et al., 2010).

For example, there is a sharp interface between the two phases during the displacement process and this interface is steadily expected to decrease, since the two phases diffuse into a mixed grade zone ranging from one pure fluid to other. In the study conducted by (Amin et al., 2010), the thermodynamic stability of the interface was the time dependent that coexisted with molecular diffusion. As a result, both studies (Sidiq and Amin, 2012; Amin et al., 2010) reported that although the two phases are miscible, their relative permeabilities at pore scale can be affected by pore morphology of the porous medium and the mechanisms of dispersion and molecular diffusion

There are many reservoir simulation studies that have been carried out to comprehend by process of CO₂ injection into depleted natural gas reservoirs, none of these studies has ever attempted to explain the effect of gas-gas (CO₂-methane) flow in porous media, particularly relative permeability. Hence modeling relative permeability curves for a gas-gas system in a reservoir porous medium has been a great challenge to this research. Estimation of relative permeability in such away is important, since the gas phases undergo a series of changes at different pressures and temperatures while propagating in porous media. Thus at the transition zone, miscible fluid will occur between pure injected SCO₂ and pure methane and will have a great influence on the shape of the relative permeability.

The presented relative permeability curves in this chapter are combined with the other petro-physic parameters of core plugs (mentioned in next chapter) and imported into the reservoir simulation software to investigate the process of CO₂ injection for enhance gas recovery and storage under different conditions of the reservoir.

Chapter Four

Reservoir Simulation Model

4.1 Overview

Most of the recent practices of predicting hydrocarbon production and controlling recovery processes are dominated by reservoir simulation software. However, there is still lack of understanding of properties and behaviour in porous media (Fleury, 2002). With regards to miscible displacement processes, a proper scaling of this process is difficult and expensive to obtain, although it is considered as one of the most attractive areas for current research. This trend has increased interest in the use of reservoir simulation in the oil and gas reserves estimation process for field development and planning purposes (Rietz & Usmania, 2009). This chapter aims to predict optimal trade-offs between maximum methane production and CO₂ storage throughout the production life of this particular gas reservoir. This task is performed by using the Tempest commercial reservoir simulation software produced by ROXAR. This software has integrated a limited number of the models that have been proposed in the current literature to control and develop a generalised compositional simulator. In general, the compositional simulators are standard black oil simulators that have been converted to include the Todd-Longstaff mixing model, where two components exist such as the original gas in place and the solvent gas as injection (Todd & Longstaff, 1972).

4.2 Reservoir simulator

4.2.1 K-value formulation of the black oil model (Al-Awami & Ponting, 2003)

Some phase behaviour models make the simplifying assumption that the equilibrium K-values are independent of composition, i.e., as functions only of pressure and temperature. An equilibrium K-value is the ratio of the mole fraction of a particular component in the gas phase to its mole fraction in the oil phase. A K-value greater than one means that the component is predominantly in the gas phase; a K-value less

than one means it is predominantly in the oil phase. A K-value equal to one means it is partitioning uniformly between both oil and gas phases (Tang and Zick 1993).

K-value formulation commonly is used in compositional simulators. For example, the K-value of a component is $K_c = y_c/x_c$, where y_c and x_c are the mole fractions of component c in the gas and oil, respectively. For two components the Rachford-Rice expression is linear and may be solved explicitly. The K-values become functions of pressure in this picture and can be obtained from experiments such as constant volume depletion. The formulation of the phase equilibrium problem in terms of K-values makes the extension to multi-gas systems straightforwardly. For three hydrocarbon components the Rachford-Rice equation is quadratic. For more than three components the Rachford-Rice can be solved numerically (Al-Awami & Ponting, 2003).

It is convenient to define a molar solution gas-oil ratio R_{sm} as:

$$R_s^m = R_s \cdot (\rho_g / Mw_g) / (\rho_o / Mw_o) \quad (4.1)$$

A molar vapour oil-gas ratio may be defined in a similar way:

$$R_v^m = R_v \cdot (\rho_o / Mw_o) / (\rho_g / Mw_g) \quad (4.2)$$

For a simple black oil model the K-values are:

$$K_o = R_v^m \cdot (1 + R_s^m) / (1 + R_v^m) \quad (4.3)$$

$$K_g = (1 + R_s^m) / (R_s^m \cdot (1 + R_v^m)) \quad (4.4)$$

In the solvent model pressure dependent K-values are obtained using these expressions for the oil-reservoir gas and the oil-solvent system. Phase equilibrium calculations are then performed using a 3-component K-value flash.

If $G(0) < 0$ fluid is single phase oil

If $G(0) > 0$ fluid is single phase gas

In the case in which oil is not volatile, the $G(0)$ condition reduces to $K_{g,z,g} < 1$.

The mole fraction of hydrocarbon in the vapour phase may be obtained using the usual Rachford-Rice equation:

$$V = (1 - (K_o + K_g) / 2) \times ((1 - K_o) \times (1 - K_g)) \quad (4.5)$$

The K-values for the solvent are obtained from the saturated solvent-oil data:

$$K_s = (1 + R_{ss}^m) / (R_{ss}^m \cdot (1 + R_{vs}^m)) \quad (4.6)$$

Again, in the case in which the oil is not volatile, the condition for single phase oil is simple:

$$K_{g,z,g} + K_{s,z,s} < 1$$

In this case the Rachford-Rice equation is a quadratic and can still be solved analytically.

where R_s is the solution gas-oil ratio, m is the “superscript” Molar quantity, m is the “subscript” mixture, p is the stock tank density, M_w is the molecular weight, g is the gas-phase index, o is the oil-phase index, s is the solvent gas component, K is the K-value of the component, R_v is the vapour oil-gas ratio, and Z is the mole fraction of component in hydrocarbon.

4.2.2 Todd-Longstaff viscosity mixing model (Todd & Longstaff, 1972)

Tempest controls proper scale of miscible displacement by using Todd-Longstaff viscosity model. When phase viscosities are obtained in a reservoir simulation, these are usually simply assigned to the appropriate phase. However, when fluid is injected at adverse mobility ratio fingering is expected, so that the oil and gas phases become intermingled. The original Todd-Longstaff model is merely a useful feature to

account for viscous fingering. The model is considered two components original gas and solvent in a single phase.

The Todd-Longstaff model sets the viscosities for the oil and gas phases to a combination of the pure phase viscosity and a combined oil-gas mixture viscosity. In addition, the model addresses the issue of inter-phase mixing and replaces both the oil and gas viscosity by an expression which is a function of the parameter ω . In terms of velocities for the two components, the basic idea of Todd-Longstaff is based on the viscosities of the two components and an adjustable mixing parameter ω . Therefore, where the $\omega \rightarrow 1$ case corresponds to complete mixing and the $\omega \rightarrow 0$ to no mixing. The effective oil and gas phase viscosities become (Al-Awami & Ponting, 2003):

$$\mu_{oe} = \mu_o^{1-\omega} \cdot \mu_m^\omega \quad (4.7)$$

$$\mu_{ge} = \mu_g^{1-\omega} \cdot \mu^\omega \quad (4.8)$$

The mixing viscosity is constructed using a quarter-power mixing rule (Al-Awami & Ponting, 2003):

$$\left(\frac{1}{\mu_m}\right)^{1/4} = \left(\frac{S_g}{S_n}\right)\left(\frac{1}{\mu_g}\right)^{1/4} + \left(\frac{S_o}{S_n}\right)\left(\frac{1}{\mu_o}\right)^{1/4} \quad (4.9)$$

$$\mu_m = \mu_o \mu_g \div \left(\frac{S_g}{S_n} \cdot \mu_o^{1/4} + \frac{S_o}{S_n} \cdot \mu_g^{1/4}\right)^4 \quad (4.10)$$

In these equations, μ is viscosity, o is oil, e is effective, g is gas in four-component simulator, solvent in three-component simulator, ω is mixing parameter, m is mixture, S is saturation, s “subscript” is solvent, n is non-wetting (hydrocarbon). For the application of the mixing parameter model, it is assumed that oil viscosity and density are modified only by the presence of the solvent, as are the viscosity and density of the gas. The viscosity and density of the solvent, however, are modified by both the oil and the gas since the solvent shares dispersed zones with both of these

components. Correspondence to the above equations, Todd-Longstaff modified the following equations (Todd & Longstaff, 1972):

$$\mu_{oe} = \mu_o^{1-\omega} \cdot \mu_{mog}^{\omega} \quad (4.11)$$

$$\mu_{se} = \mu_s^{1-\omega} \cdot \mu_m^{\omega} \quad (4.12)$$

$$\mu_{ge} = \mu_g^{1-\omega} \cdot \mu_{mSg}^{\omega} \quad (4.13)$$

Where, with $S_{oS} = S_o + S_g$ and $S_{Sg} = S_s + S_g$,

$$\mu_{moS} = \mu_o \mu_s \div \left(\frac{S_o}{S_{oS}} \cdot \mu_s^{1/4} + \frac{S_s}{S_{oS}} \cdot \mu_o^{1/4} \right)^4 \quad (4.14)$$

$$\mu_{mSg} = \mu_s \mu_g \div \left(\frac{S_g}{S_{Sg}} \cdot \mu_g^{1/4} + \frac{S_s}{S_{Sg}} \cdot \mu_s^{1/4} \right)^4 \quad (4.15)$$

$$\mu_m = \mu_o \mu_s \mu_g \div \left(\frac{S_o}{S_n} \cdot \mu_s^{1/4} \cdot \mu_g^{1/4} + \frac{S_s}{S_n} \cdot \mu_o^{1/4} \cdot \mu_g^{1/4} + \frac{S_g}{S_n} \cdot \mu_o^{1/4} \cdot \mu_s^{1/4} \right)^4 \quad (4.16)$$

Equation (4.16) is the quarter power fluidity-mixing rule for three miscible hydrocarbon components. The effective densities for the three miscible components maybe calculated in a manner analogous to that described in the body of the paper (Todd & Longstaff, 1972).

4.3 Geological model

The base reservoir model used in this study is based on a known field in the North West Shelf of Western Australia. It is composed of sandstone which has homogeneous layer-cake geology and contains natural gas at a depth of 3650 metres. Reservoir core samples were studied experimentally to accurately estimate the general petro-physical characteristics of the reservoir. The physical properties for each one of the tested cores were used as the base assignment to represent the geological model. The reservoir properties were then allocated throughout the

reservoir simulation based on the interpretations of each pore plug. The gas reservoir model was created and controlled by various cell distributions in terms of width, length and thickness. The dimensions of the geological model, in the X-grid 32 grid-blocks used and 44 grid-blocks used in the Y-direction. The divisions in the Z-direction vary by layers, with 4, 5, 6 and 4 grid-blocks formed to represent layers L1, L2, L3 and L4, respectively. The parameters values are distributed in such a way, to provide a close approximation to reality. From the upper part of the geological model, the thickness of the first layer is 50 m, and has a value of 0.04 porosity, 0.05 for critical gas saturation and 0.120 for critical water saturation. The permeability values distributed as 6, 6 and 4 md for x, y and x directions respectively. For the second layer from the top of the reservoir, it has a thickness of 70 m. Porosity, critical gas and water saturations values for the existence thickness determined as 0.17, 0.03 and 0.175 respectively. In addition, permeability values for this layer distributed as 390, 390 and 370 md for x, y and z. The third layer of the reservoir model organised as porosity of 0.14, gas critical saturation with value of 0.04 and 0.145 for critical water saturation with a thickness of 120 m. The bottom layer is also characterised by a porosity of 0.09, a critical gas saturation of 0.04 and a water saturation of 0.100. Permeability for the three directions of the last layer is presented as 8.5, 8.5 and 6 md for x, y and z. Thus, the geological arrangement of the layers from top to bottom of the reservoir model start as very low, high, medium and low quality rock, respectively (Table 4.1).

Table 4.1: General reservoir characteristic by layer

Layer	Z thickness (m)	Z direction (cells)	Kx (md)	Ky (md)	Kz (md)	Porosity (%)	Sgcr	Swcr	Core plugs
Very low	50	4	6	6	4	0.04	0.05	0.120	S_A_4
High	70	3	390	390	370	0.17	0.03	0.175	S_A_1
Medium	120	6	115	115	100	0.14	0.04	0.145	S_A_2
Low	60	4	8.5	8.5	6	0.09	0.05	0.100	S_A_3

In terms of gas/water contact, reference depth of the reservoir, pressure and temperature at the reference depth and depth specifying the Water-Gas contact was calibrated to achieve the equilibrium initialisation. This provides indications of a transition zone between gas and water. As a result the simulator will take these values into account and stabilise the initial aquifer zone, which is allocated in depths of the bottom cells in the gas reservoir model. Beneath of this aquifer zones is the

target for drilling and completion the injector wells. In general, the modelled aquifer in the subsurface of this gas reservoir meets the physical conditions of aquifers. First, the top layer of the aquifer is at a depth of “4400 m”. Gaspar et al. (2005) claim that aquifers beyond the depth of 800 m make CO₂ to act as a supercritical fluid and relatively it would have density as high as that for water. In addition, CO₂ density in aquifers with depth of greater than 3500 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 CO₂ in the aquifer. Injected CO₂ at the gas-water contact of the reservoir model has potential to act as a substitute support for pressure maintenance, thereby allowing simultaneously production of gas. In addition, we anticipate that the process will improve displacement efficiency and result in increased ultimate recovery factor (Khan et al. 2012). To understand the impact of the reservoir geology on potential development schemes under consideration, the initial composition, the development of rock layers and properties are modelled using the “tempest” reservoir simulation software. In terms of reservoir homogeneity, the rock properties in each model layer are estimated to be homogeneous over the entire grid. The simulator incorporates the detailed results of experimentally tested core plugs which represent different general geological characterizations by layer as shown in Table 4.1. The simulation process uses the ‘Solvent’ option of the reservoir simulator, an extended black-oil model in which components coexist. The simulation standard compositions (SCMP) are reservoir gas (RESV) and solvent gas (SOLV). The reservoir gas depicts the mole fraction of the components in the mixture of the gas reservoir, which originally represents gas initial in place. The solvent gas specifies the solvent concentration in the injected gas (CO₂). The initial pressure of the reservoir model is set at 406 bar and temperature of 160 C. ‘PVT-software’ was used to generate the necessary PVT data for simulation. Table 4.1 shows the different porosity, absolute permeability, critical gas saturation (S_{gcr}) and critical water saturation (S_{wcr}) for each layer. Furthermore, the relative permeability curves are generated using Darcy’s Law to achieve displacement between the gases. Therefore, the development of the geological model is designed to illustrate optimisation of the gas recovery initial in place. In order to determine the optimal development plan and to test its robustness over the uncertainty range of reserves, a number of dynamic reserve simulation models are constructed.

Table 4.2: Reservoir model parameters

Property	Value
Reservoir type	Sandstone
Reservoir depth	3650 m
Area (X-Y direction)	1700 m x, 2300 m y
Thickness (z direction)	300 m
Grids in X direction	17
Grids in Y direction	22
Grids in Z direction	4, 5, 6 and 4 for L1, L2, L3 and L4
Relative permeability	JBN method and Darcy's law
Initial reservoir temperature	160 °C
Initial reservoir pressure	406 bar
Well injector pressure (maximum)	450 bar
Well producer pressure (minimum)	50 bar
CO ₂ injection rate	1,150,000 and 576,000m ³ /day
Maximum gas production rate	12,800,000 m ³ /day

Over all, for all scenarios the initial component names in the gas mixture are listed as C₁, C₂, C₃ and CO₂. A mole fraction or initial composition of each one of the mentioned components is 0.9, 0.005, 0.005 and 0.09 respectively (Table. 4.3). Production of these gases can be economically advantageous and replacing the produced gas would allocate extra space for further CO₂ deposition.

Table 4.3: Compositional table

Component	Composition
CO ₂	0.09
C ₁	0.9
C ₂	0.005
C ₃	0.005

In addition, a simplified gas layered model in which the components coexist consists of 3.2×4.4×0.3 km grid cells (see Table 4.2). Rock properties, well properties and completion are assigned to the various thicknesses in the layers across the grids (Table 4.4). This is to ensure the development concepts consistent of surface facilities with physical constrain imposed by various surface facility options, especially when the concepts of CO₂ separation, compression, transportation and injection are applied. The detailed geological modelling is used to test the selected development plans against wide range of geological outcomes. This model incorporates significant areas of local grid refinement to properly model the fluid flow in the neighbourhood of the production wells. The base case development plan calls for four vertical production wells allocated in the upper layers of the reservoir

and their perforation locations are differently placed with various vertical lengths according to the structure of the layer (see Table 4.4). These production wells are expected to produce natural gas at different rates. In general, the production wells are controlled as a function of a maximum gas production rate per day and a minimum producing bottom-hole pressure for each well. The summation of the production rates for each one of the wells is equivalent to the total gas production per day 12.8 cubic meters per day (12,800 km³/day) of the reservoir simulation. The simulation suggests that there is sufficient vertical permeability in the reservoir to allow the gas in the lower portions to move towards the wells. Two gas injector wells are proposed in the following different cases to dispose of the produced CO₂ by re-injecting into the gas reservoir down-dip of the production wells. The perforated locations of the wells will be at a distance such that CO₂ breakthrough at the production wells is after the plateau production (Khan, et al. 2012). By contrast to the producer wells, the two injection wells are perforated in the bottom layer beneath the zone of G/W contact in order to take gravity effects into account. This potentially has enough capacity to handle breakthrough volumes as well as CO₂ re-injection.

Table 4.4: Well placement and completion depth

Well	Type	X (m)	Y (m)	MD (m)	Completion (m)	RAD (m)	Layer
I-1	Injector	1475	2025	4350-4638	4596-4638	0.5	L4
I-2	Injector	675	225	4357-4645	4604-4645	0.5	L4
P-1	Producer	525	1675	3628-3915	3628-3661	0.5	L1
P-2	Producer	975	1125	3696-3984	3696-3730	0.5	L1
P-3	Producer	1275	625	3650-3938	3650-3684	0.5	L1
P-4	Producer	325	1175	3876-4163	3876-3909	0.5	L1

4.3.1. Three-dimensional simulation of a base-case

The simulation grid, reservoir physical properties and the layout of the reservoir model is displayed in Figure 4.3. The objective is to investigate the influence on the flow through the main reservoir characteristic units, likely porosity, permeability, water and gas saturation, CO₂ injection rates and also CO₂ production rate in the gas production. In addition to this case, the maximum gas production is set at 3.2 million cubic meters per day for each one of the production well. In order to test the model, the reservoir layers are estimated to be filled with homogeneous compositions in the gas mixture (Table. 4.3). Simulation of natural gas production without any injection

is performed for a base-case under normal production conditions in such a way that the bottom-hole wells pressure declines over a time period of 20 years. Therefore, a number of 3D geological models are constructed to reflect potential variations in the reservoir distribution such as reference pore volume; water and gas phase saturation (Figure. 4.1 and 4.2).

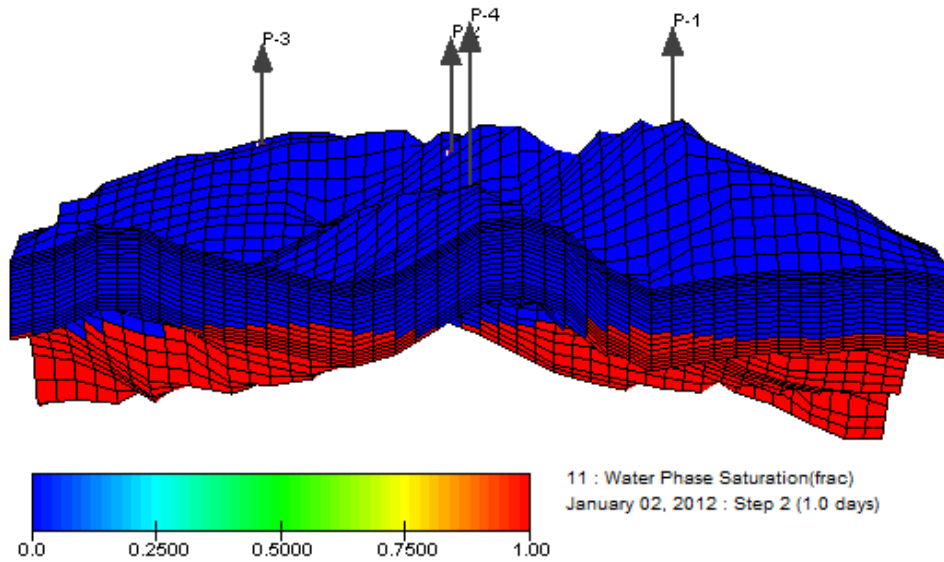


Figure 4.1: Water phase saturation

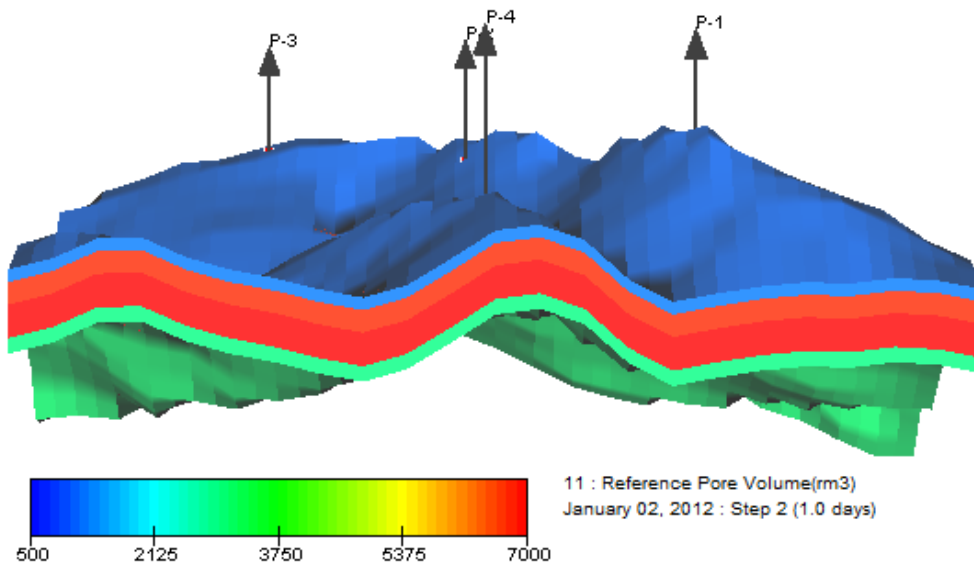


Figure 4.2: Reference pore volume of the reservoir

In this way, potentially the full range of the reservoir geological is carried through the dynamic reservoir modelling. As a consequence, the proposed development scenarios can be optimised over the range of the reservoir uncertainty and also illustrate the sweep efficiency of CO₂ injection. Additionally, cumulative methane

and CO₂ production “lb-mole” and bottom-hole pressure “bar” are estimated for this case over the estimated 20 years (Figure. 4.4 and 4.5). This case is intended to be the basis for comparison, to illustrate the acceleration of methane production, and (hopefully) lower CO₂ production under a case of CO₂ injection as a function of given various rates and times of injection. The bottom-hole pressure (BHP) is measured in this case and under a late stage of CO₂ injection, the measured BHP decline is used to determine the time start of CO₂ injection.

4.3.2. Optimization of gas recovery and CO₂ storage

The simulation suggests that there is sufficient vertical permeability in the reservoir to allow the gas in the lower portions to move towards the wells. The proposed injection wells are each sat at rate of 1.15 million cubic meters per day. In addition, it has been anticipated that the injection process will improve displacement efficiency and potentially results in increased ultimate recovery factor and reservoir re-pressurisation compare to the base case (where injection is not considered). The subsurface development plan has been designed to optimise the recovery of gas in place and storage. The produced CO₂ will be disposed by means of injecting it into the gas reservoir down-dip of the production wells. The principal aim of the simulation is to illustrate a re-injection strategy of an optimal CO₂ injection for enhanced gas recovery and CO₂ storage. This purpose is investigated through determining the optimum injection target rate, the time response of CO₂ injection and as a result, illustration of mixing rates between the gases.

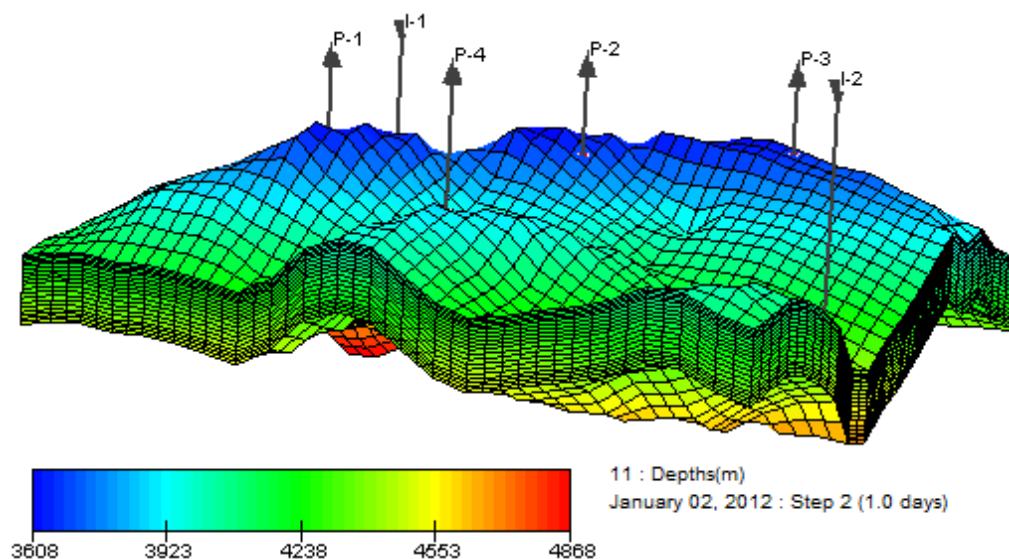


Figure 4.3: Hypothetical gas reservoir model

The simulation model has been used to test whether the chosen development plan is optimal of the range of reserve expected and robust under different assumptions for key parameters in the reservoir description. Re-injection of the produced CO₂ into a down-dip location of the gas reservoir model is considered as the preferred disposal method. The injected CO₂ is expected to migrate to the bottom layers due to its high density. The location for the CO₂ injectors potentially was chosen to ensure both containment of injected gas with the identified structure and a suitable delay time prior to CO₂ breakthrough at the production well location. Uncertainties in this re-injection strategy are the timing of CO₂ breakthrough at the producing wells. Since the natural gas and the re-injected CO₂ will not re-mix, the initial natural gas in place could over-run the re-injected CO₂ to reach the production wells. Accordingly, CO₂ breakthrough at the producer wells is not expected to occur until after the end of the plateau production period (Hussen et al, 2012; Khan et al, 2012), in this manner avoiding any impact on natural gas production. In addition, production is expected to be influenced strongly by the aquifer zone as discussed in the previous section (Section 4.3) and vertical completion of the injector well in the lower layers of the zone potentially having an impact on breakthrough as a result sufficient recovery is expected. The recovery factor is based on selection of gas production from the wells. Based on variations in the structural and stratigraphic model range estimations of the recovery factor are different from one well to another. The recovery efficiency ranges are put together in order to establish the ultimate recovery over the life of the field as reservoir producing. Accordingly, the simulation results suggested that CO₂ injection into the lower portion of the reservoir is technically feasible for maintain reservoir re-pressurisation and enhanced methane recovery (Figures 4.4 and 4.5).

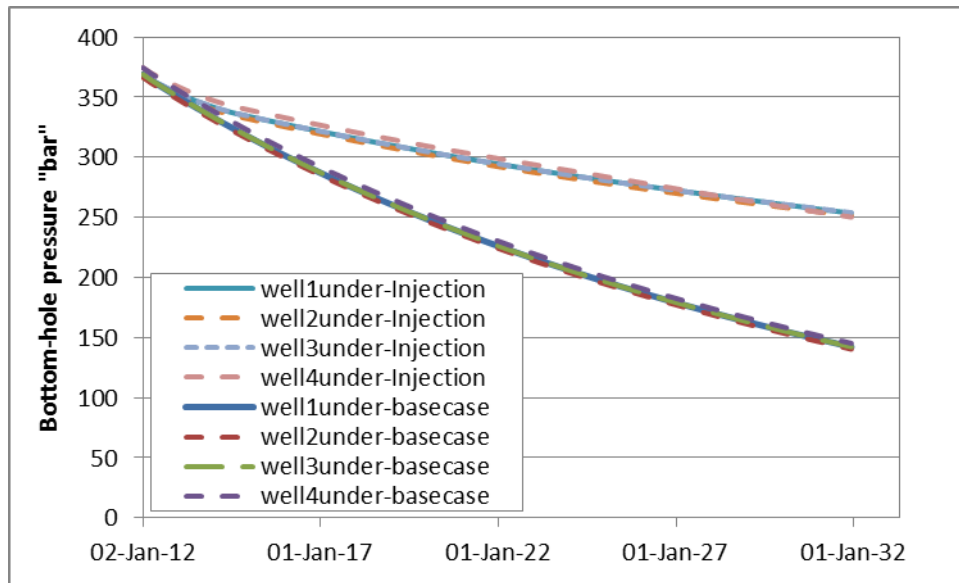


Figure 4.4: Bottom-hole pressure decline “bar”

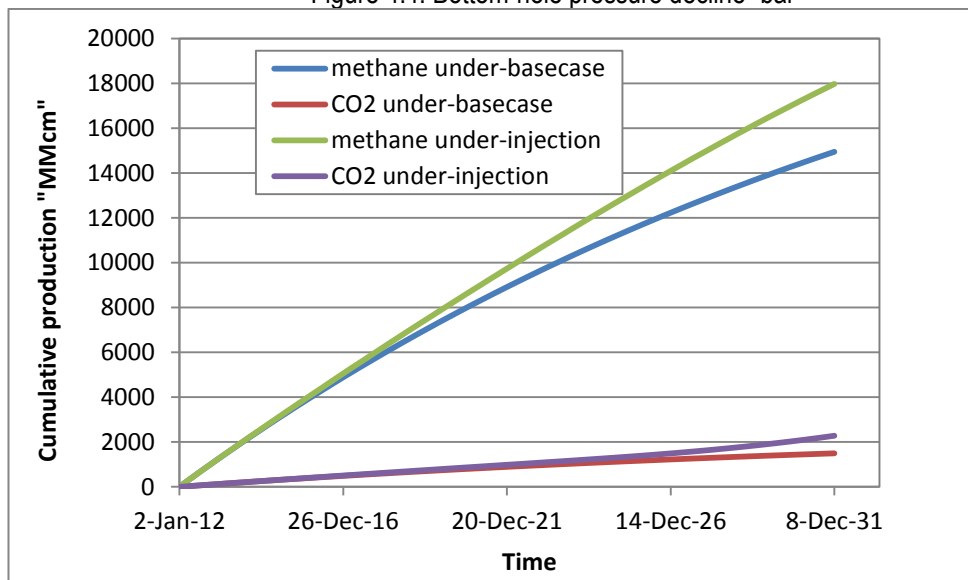


Figure 4.5: Cumulative gas production “MMcm”

4.3.3. Effects of operational parameters on enhanced recovery and storage

In this section, different simulation models are investigated based on effects of four factors and their favourability for enhanced gas recovery and storage as a preparation step to determine optimum injection strategy in terms of time and rate of CO₂ injection. Accordingly, the simulation results outline the operational parameters which are favourable for the process. Among the simulation models the best scenario is determined as a function of effects of injection pressure, well placements, effects of vertical and horizontal wells and various layers in terms of rock qualities “Core

Plugs". The results of this research study can be useful for predicting optimal trade-offs between maximum methane production and storage.

Further, layer arrangement from the top to the bottom of the reservoir could have significant impact on gas contamination. To this point, the layers of the reservoir model are arranged from the top to the bottom as very low, high medium and low quality of rock respectively. In the following section, layer arrangements are tested to determine the optimum layer arrangement for CO₂ injection as a function of enhance gas recovery and storage. This investigation is performed based on effects reservoir re-pressurisation in terms of injectivity of CO₂ and distribution of the injected CO₂ as a function of permeability. Therefore, simulation study is examined for another two scenarios still under the first case of injection. For the second scenario very low, low, medium and high rock quality and for the third scenario as high medium low and very low quality of rock are considered. Under scenario 2, injectivity of CO₂ is higher than the other two scenarios. Thus, the injected CO₂ is expected to distribute from the bottom of the reservoir faster and results in reservoir re-pressurisation faster, before it starts to rise to the top of the reservoir. But because the other two layers from the top of the reservoir represent very low and low permeability, the injected CO₂ is expected to overrun the native gases presented in the bottom of the reservoir to production wells faster than it is under the first scenario. This would have side effects on sweep efficiency. On the contrary, the third scenario represents the lowest injectivity of CO₂. In this case CO₂ is injected into very low permeable layer and the layer followed by another low permeable layer. Therefore, the injected CO₂ is expected to find its own path and potentially will prefer to break through the production wells rather than to be distributed in the bottom of the reservoir.

Overall, the results indicate that scenario 1 has the highest recovery factor of methane production and scenario 3 represents the highest CO₂ recovery factor. In addition, scenario 2 comes as the second recovery factor for both CO₂ and methane. While, scenario 3 produces the lowest methane recovery factor and scenario 1 yield the lowest CO₂ recovery factor. As a result scenario 1 is still the optimum for enhance gas recovery and storage under injection process.

Despite of reservoir layers, Feather and Archer (2010) claim that during CO₂ injection for a gas reservoir, the re-pressurization happens faster, while the actual flow of the fluid takes longer. Therefore, it is advantageous to place the injection well as far as possible from the production wells. Distance between injection and

production wells will help to increase initial gas production and delay the breakthrough of CO₂ for as long as possible (see Figure 4.7).

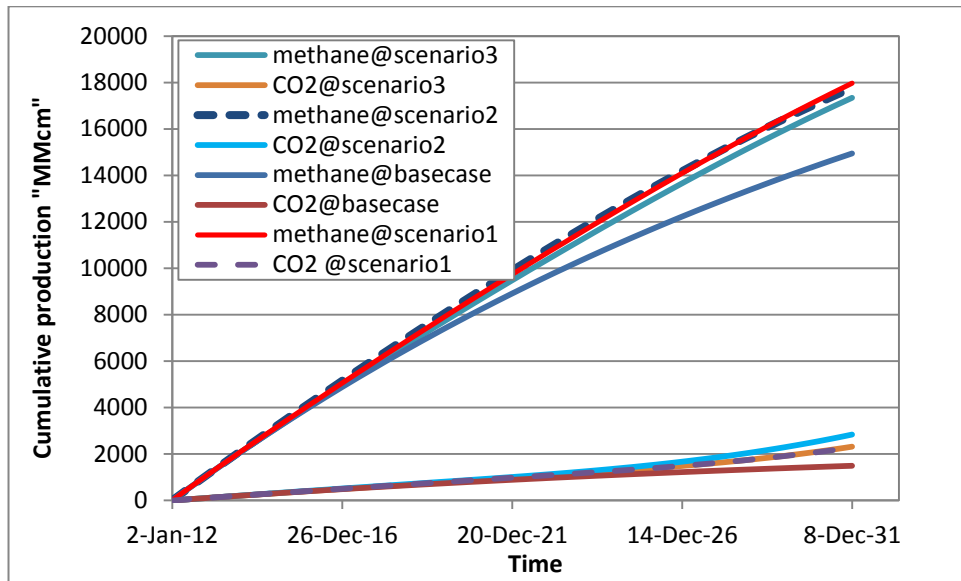


Figure 4.6: Cumulative gas production “MMcm” in millions for different scenarios

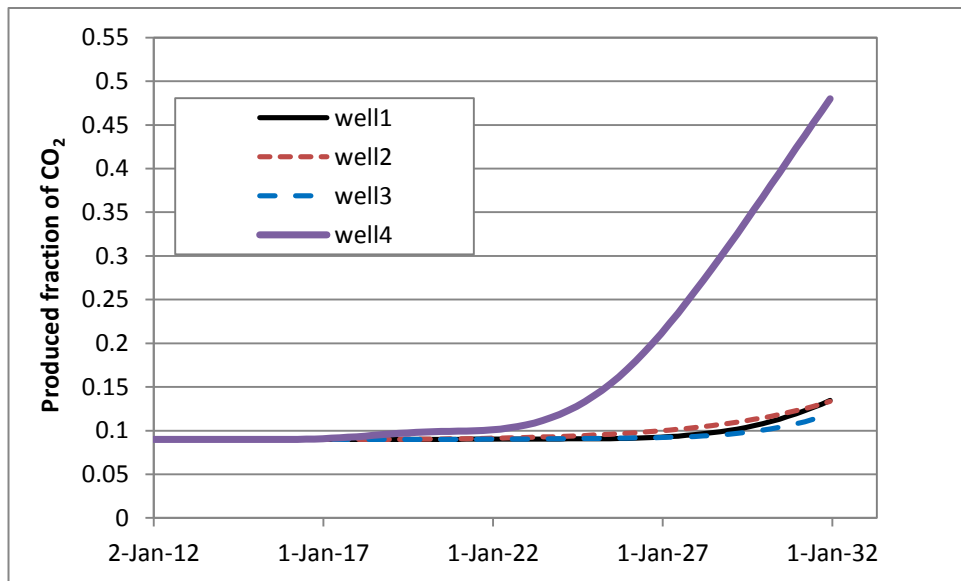


Figure 4.7: CO₂ breakthrough under the optimum scenario

Figure 3.7 shows CO₂ breakthrough under the optimum scenarios in terms of layer arrangement. It is obvious that production well 4 has the earliest gas breakthrough and the highest production contamination. Therefore, only this well is taken into account in order to plot clear figures and demonstrate the effects of some other operational parameters on the feasibility of enhanced gas recovery and storage. For the optimum scenario the simulation is run without considering solubility factor.

The results of the simulation suggest that with CO₂ dissolution in the formation water, the CO₂ breakthrough points to be in 27 December 2015 (well 1), 27 September 2015 (well 2), 25 September 2016 (well 3) and 30 June 2014 (well 4) In comparisons to these dates without case of solubility, the simulation indicates breakthrough on 26 June 2015, 28 March 2015, 20 March 2016 and 29 December 2013 for production wells 1, 2, 3 and 4 respectively. This comparison demonstrates the maximum methane production and the fraction of CO₂ remaining in the reservoir. The comparisons between the scenarios indicated that the solubility of CO₂ is greater than methane at all relevant pressure and temperature. This implies a reduction in the volume of CO₂ available in the gas reservoir to mix with methane, which potentially delays CO₂ breakthrough. The effect of CO₂ solubility obtained in this study accords with Al-Hashami et al. (2005).

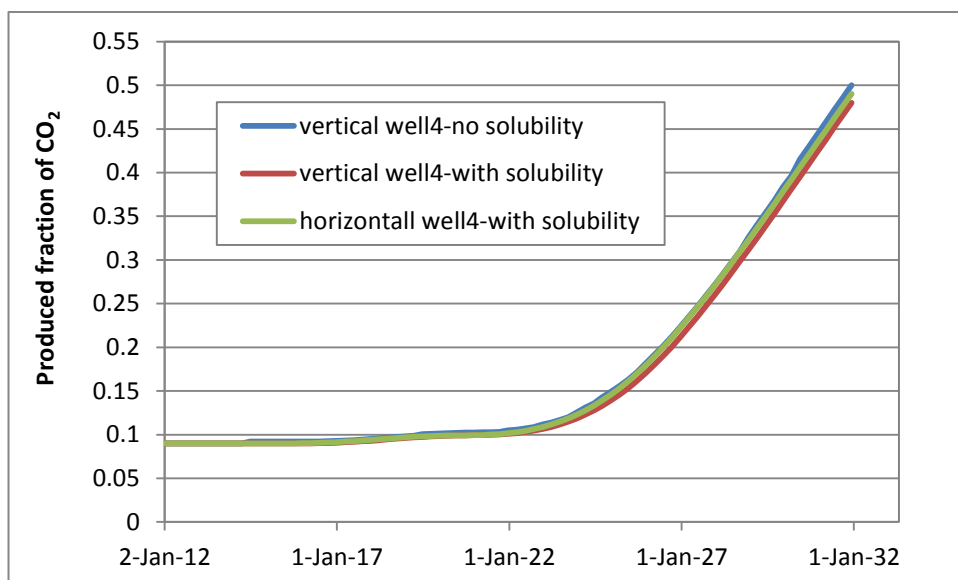


Figure 4.8: CO₂ breakthrough of well 4 under injection well pattern and solubility consideration

Thus, in the following cases continuously solubility of gas injection is taken into account. In this particular instance, also better storage of the injected gas is anticipated. Next effects of horizontal injection well over vertical well are investigated. During the last decade the petroleum industry has experienced a rapid increase in the number of horizontal wells being drilled and completed worldwide (Benayad & Osisanya 2004). Thus, the use of horizontal well in injection process is promising an additional recovery. However, according to Uzoh et al., (2010), there are still two disadvantages of horizontal wells over vertical wells; cost of drilling a

horizontal well is 1.5 to 2.5 times more expensive compared to drilling a vertical well. In addition to technical issues, drilling a horizontal well is more challenging compared to a vertical well. In general, the success rate for drilling horizontal well in the United State is about 65%, while higher successful rate is involved for vertical wells (Uzoh et al. 2010). In this chapter, simulation study was still investigated to illustrate the effects of placing horizontal well instead of the vertical injection well on enhanced gas recovery and storage. The simulation results indicated that the injection well pattern can have effects on both gas production and storage. For example, the use of vertical injection well in the reservoir geometry is considered to be efficient for CO₂ injection to improve storage purposes, while the reverse order can be attractive for enhanced gas recovery due to high injectivity of CO₂. Figure 4.8 shows that, the use of vertical well delays gas breakthrough and aids CO₂ storage, but lowers methane recovery slightly compare to that under horizontal injection well. The injection process tested under higher injection pressure (500 bar) compare to the previous injection pressure “(450 bar), both pressures are above the initial reservoir pressure and tested at the same injection rate. Wojnarowski & Rewis (2003) claimed an increase in injection pressure would bring the injection zones closer fracturing conditions, in addition to enhance the migration of the injected fluid and potentially causes early breakthrough into production wells. Under the reservoir simulation, this scenario was designed to investigate the impact of high injection well pressure on CO₂ injection performance and reservoir sweep. The simulation results indicated that the higher injection pressure results in a higher cumulative methane production and contaminated with the injected CO₂. This scenario led to decrease less expected volume of natural gas initially presented in the reservoir to be produced as a consequence of early CO₂ breakthrough occurrences due to higher CO₂ injectivity. The effect of an increase in CO₂ injection pressure on the amount of CO₂ storage leads to a corresponding increase in amount of CO₂ storage. This is due to an increase in CO₂ solubility in the formation water of the reservoir at a higher pressure.

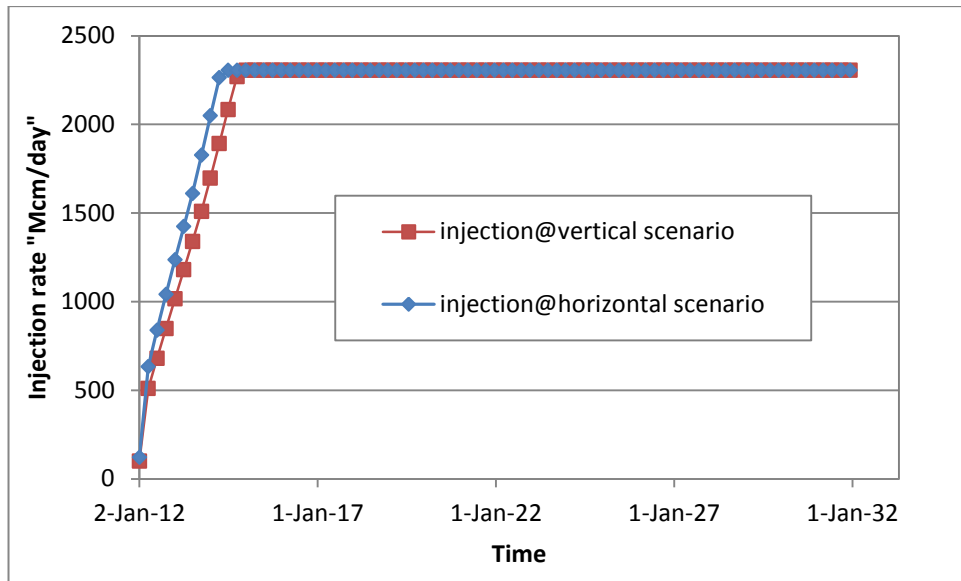


Figure 4.9: CO₂ Injection under different will injection pattern

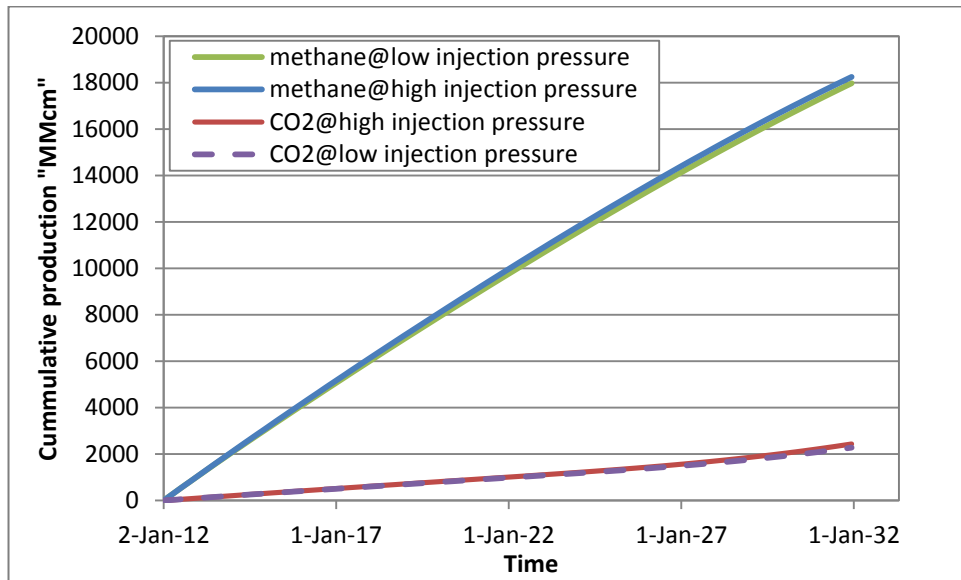


Figure 4.10: Cumulative gas production under different injection pressure

4.3.4. Effects of stages and rates of CO₂ injection

In this case the optimum scenario 1 “ arrangement layer” with considering the more attractive operating parameters, such as solubility factor of the injected gas mixture, vertical injection well pattern, the lower injection pressure, all tested at lower injection rate as a second case. The objective of this case is to investigate the effects of CO₂ injection rate on enhanced methane recovery and CO₂ storage. Thus, CO₂ is injected in the beginning of gas production at rate of 5.76 million cubic meters per day for each injector well. The total maximum injection rates of the wells partially

are 9% of the total maximum gas production rate of the reservoir. To achieve higher injection rate, additional amount of CO₂ is required to reach to the required rate of injection. Economically, this may have jeopardising influences on the project. Because the higher is the injection rate the more costs would be involved in the process of CO₂ capture and storage. In this study, the focus is on reinjecting the produced CO₂ from the production stream directly to the sink rather than venting it into the atmosphere. This is for the purposes of environmentally friendly, production enhancement and beneficial of carbon credit. Therefore, CO₂ injection rate sat as close as the production rate of CO₂, during the injection strategies, any extra or less CO₂ requirement compared to CO₂ production will be considered in terms of cost of CO₂ capture and storage (see Chapter 5). In this prospective, costs of CO₂ might not have big jeopardizing effects compare to that under the higher injection rate.

Figures 4.11 and 4.12, illustrate comparisons between high and low injection rates as a function of enhanced gas recovery and CO₂ breakthrough. The comparison between the two different injection rates indicates the gas recovery factor under the high injection rate is greater than that in the lower case and the base-case. Accordingly, the bottom-hole pressure decline less gentle than it is under the high rate of injection. On the other hand, Figure 4.11 demonstrates different times of CO₂ breakthrough under different injection rates and indicate that the high injection rate of CO₂ the earlier breakthrough is occurred. As a result the, the simulation suggested that even though CO₂ injection excessive gas mixing, at the same time it has potential to increase incremental gas recovery and maintain reservoir re-pressurisation.

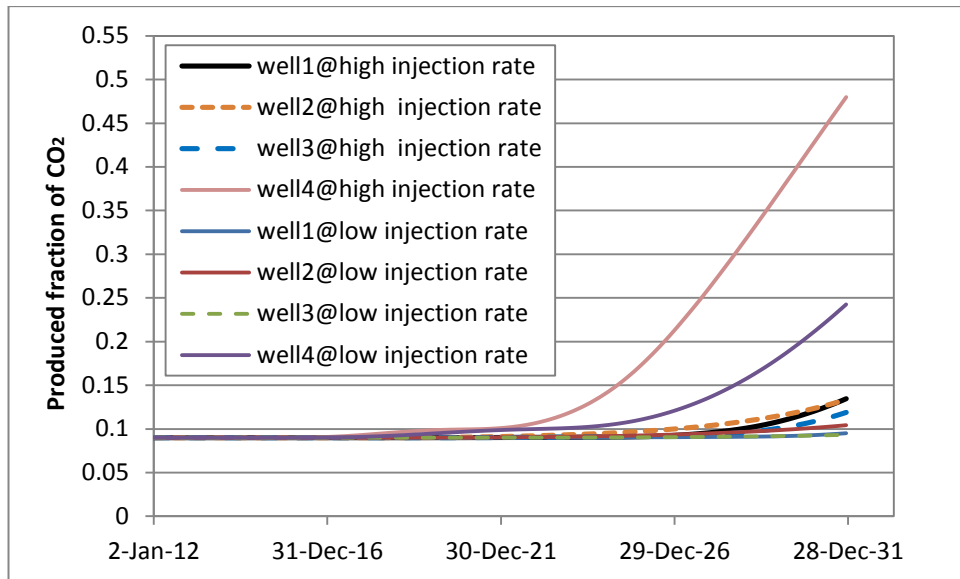


Figure 4.11: CO₂ Breakthrough under different injection rates

Next another simulation model is performed to investigate the impact of late stage commencement of CO₂ injection on production performance as a third case. This case scenario attempts to find CO₂ injection timing for comparison with the recovery factors in the above scenarios using data obtained experimentally. In this case, reservoir heterogeneity accelerated the CO₂ breakthrough in the production well, and off course reservoir re-pressurization was considered as additional support for mitigation against CO₂ breakthrough. Accordingly, CO₂ is injected at the high rate 1.15 million cubic meters per day based on the normal case, when the average bottom hole pressure of the production wells decline to about 275 bar in December 25, 2017 as shown in Figure 3.4.

That is, only a fraction of the methane is produced before injection. However, after almost six years of gas production, CO₂ is re-injected back into the reservoir at the high rate to re-pressurize and increase incremental gas recovery, resulting in continuation of gas production for the wells. The first production well that shows CO₂ breakthrough is automatically shut-in at that time. When the concentration of CO₂ in the produced gas is reached 10% in September 15, 2024, the shut-in production well (Well 4) is converted to become Injector 3, this is to accelerate methane production, with less CO₂ production for the life of the reservoir. The converted well will have a changed depth completion of 4,122 to 4,163 meter from the first layer to the bottom layer of the reservoir.

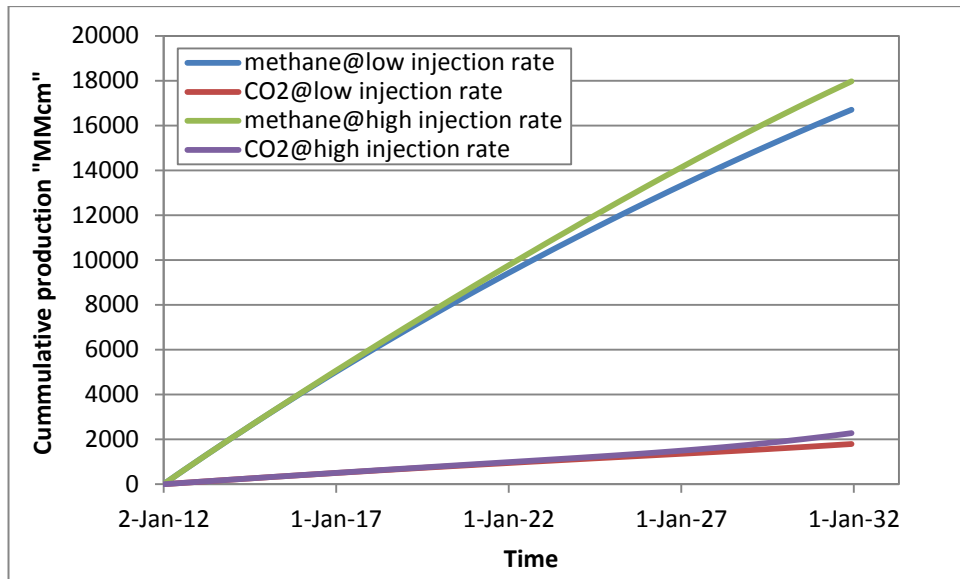


Figure 4.12: Cumulative gas production under different injection rates

In the beginning of gas production there are four gas producers well. The maximum gas production rate of each producer well set at 3.2million cubic meters per day. At the stage of injection, the maximum injection rate of CO₂ for the injector wells is 1.15 million cubic meters per day as it was under the first case scenario. After the conversion of the producer well, the gas production rate of the producers well is re-sat at 4.266667 million cubic meters per day for each existing well and the injection rate is re-set at rate of 7.666667 million cubic meters per day for each one of the new and the old injector well (Table. 4.5).

Figure 4.13 shows the remaining production wells (1, 2 and 3) after the convert-ion of the production well 4, and also illustrates different CO₂ contamination at each one of the remaining production wells as a function of late commencement of CO₂ injection, so as to reduce CO₂ production as much as possible to achieve economic feasibility.

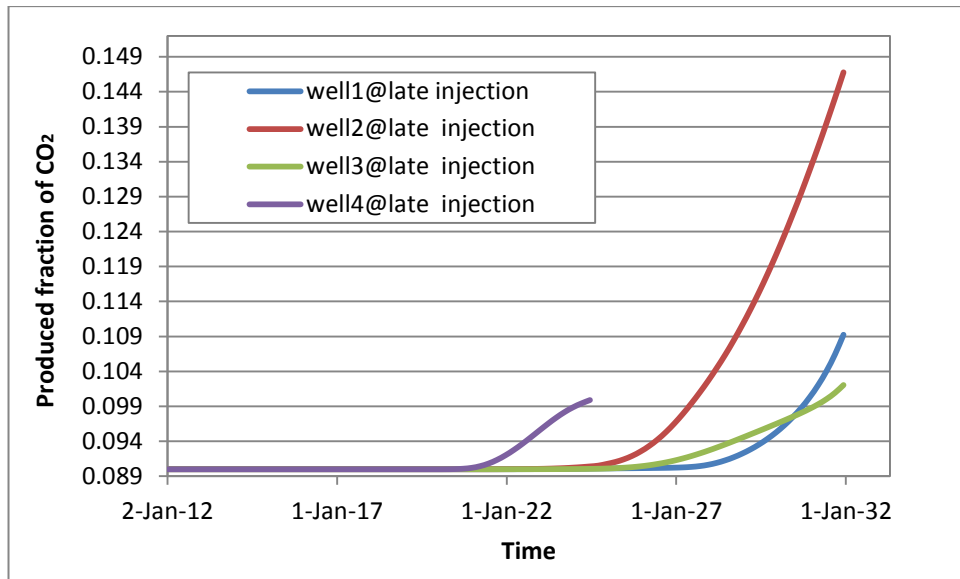


Figure 4.13: Fraction production of CO₂ under late stage of injection

Under late stage of injection, the total cumulative methane and CO₂ production for the wells are compared to that under early stage and low injection rate (see Figure 4.14). The timing of the events has an important role in illustrating the optimum injection rate strategy. Overall, early stage at high rate of injection is considered as the optimum strategy due to its higher methane production. While this case produces the highest CO₂ production among the other cases. In addition, late stage under the same high injection rate is appeared to be near the optimum case. In addition to this case, first of all, the higher methane recovery is achieved compare to the case under low injection and the base case. Second, this case yielded lower CO₂ production compared to the other two cases under CO₂ injection application. Finally, the effects of the different cases on CO₂ storage are demonstrated in the following sections.

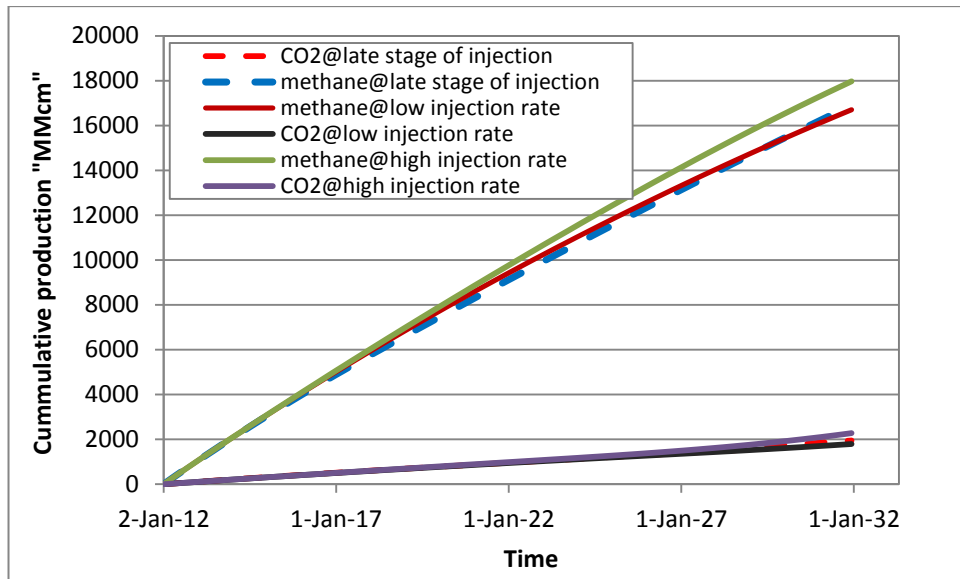


Figure 4.14: Cumulative gas production under different rates and stage of injection

4.3.5. Storage of CO₂ injection

Storage volumes of CO₂ are documented by using well established mass balance method developed through the results of the reservoir simulation. This method quantifies the volume of CO₂ initially in place and tracks the changes in the producible volumes as reservoir management techniques, when CO₂ injection is applied during the life of the field. Estimation of CO₂ storage is based on the idea of CO₂ breakthrough for the production wells. It is estimated that 9% of CO₂ is present in the reservoir and 90% for methane. In addition, Figure 4.15 also depicts the total produced CO₂ fraction in the reservoir when there is different injection of CO₂ at different stage only with consideration of CO₂ solubility. As a result, when there is injection, the produced fraction of CO₂ is increased due to the produced fraction of injected CO₂.

Under the case of late injection, total CO₂ fraction is declined in September 15, 2024, this is due to the cessation of well 4 when CO₂ concentration exceeded 10%. After when the concept of CO₂ breakthrough is illustrated, during CO₂ re-injection process the fraction of the produced CO₂ that exceeds the CO₂ fraction initially has been presented in the reservoir will represent the produced fraction of the injected CO₂ (PFICO₂) (Figure 3.15).

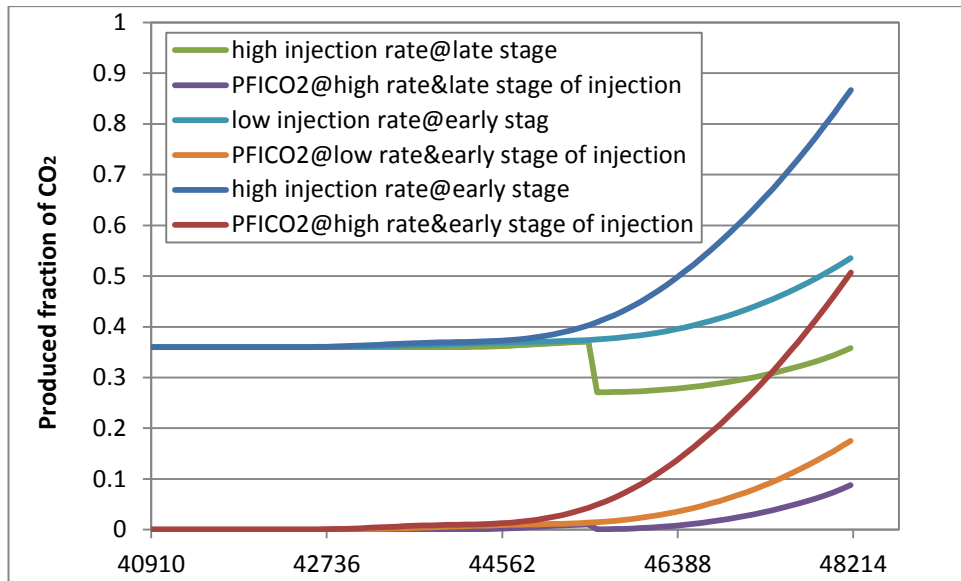


Figure 4.15: Total fraction of CO₂ production and fraction of the injected CO₂ under different case scenarios

In addition, the higher CO₂ injection the more fraction of the injected CO₂ is produced. Thus, the more produced fraction of the injected CO₂ the lower volume of the injected CO₂ is stored. Figures 4.16 and 4.17 show different injection rates at different stages of injection for all the cases and also illustrates gradual increases in CO₂ injection rates, until each case reaches the required rate of CO₂ injection. For all the cases, any extra or less CO₂ requirement compared to CO₂ production will be considered in terms of cost of CO₂ capture and storage. In addition, the extra amount of CO₂ is assumed to be provided from a close by power plant.

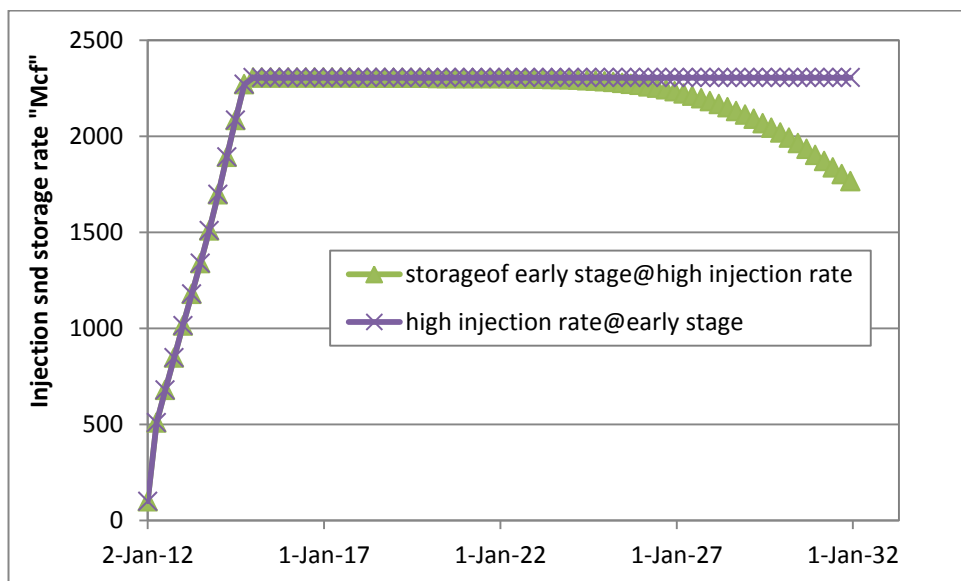


Figure 4.16: Total CO₂ injection rate and storage for early stage at high injection rate

Under the stage of late injection, it is worthwhile to mention that the injected CO₂ is reached to the required rate of CO₂ injection faster than the other cases. This is due to the gas production before the commencement of CO₂ injection. Therefore, when CO₂ injection starts, the injected CO₂ displaces the initial natural gas already has been produced from the gas reservoir and after a few months reaches to the desirable rate of injection.

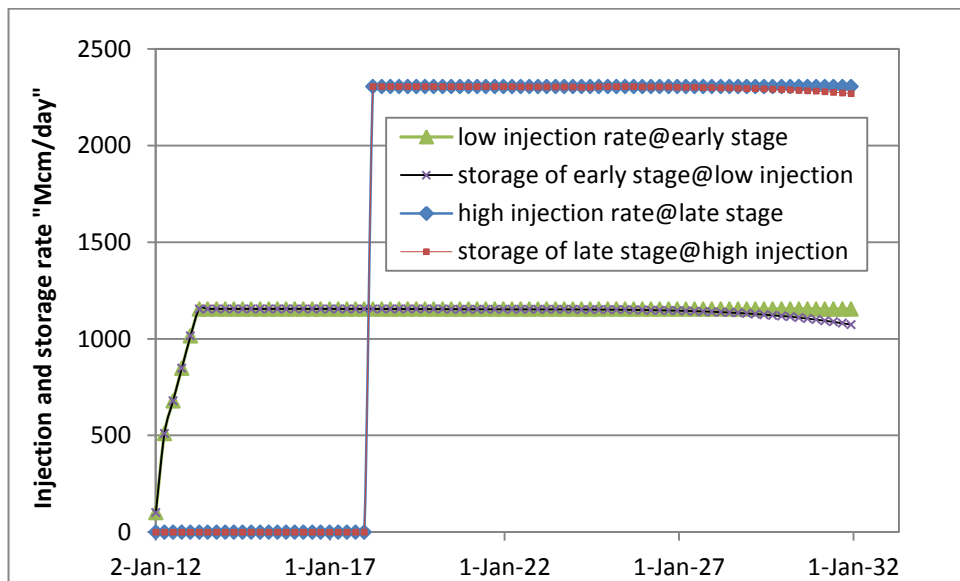


Figure 4.17: Total CO₂ injection rate and storage for early and late stages at different injection rates

CO₂ storage is evaluated after when the concept of CO₂ breakthrough illustrated for the two case scenarios in terms of the produced fraction of injected CO₂ (PFICO₂) and CO₂ component originally present in the gas reservoir. After the estimation of the PFICO₂ for each one of the cases, production rate of the injected CO₂ is calculated by multiplying the PFICO₂ from each well by production rate of CO₂ at the same during CO₂ injection. In addition, a difference between the total production of the injected CO₂ and the injection rate evaluates CO₂ storage of the injected CO₂ for each one of the cases (Figures 4.16 and 4.17). As it can be seen, the higher injection rate the higher volume of CO₂ storage is achieved. During the CO₂ injection process, part of the injected CO₂ dissolves in the formation water. Therefore, an important consideration is solubility of CO₂, which is strongly associated with pressure. Accordingly, to illustrate this concept, as an optimum case consideration, the first case scenario with the highest injection rate is demonstrated with and without considering the solubility factor. To demonstrate the concept of CO₂

dissolution in the formation water presented of the reservoir model. A comparison of CO₂ production with solubility factor is taken into account as well where solubility is not considered (see Figure 4.18). This comparison is depicted in terms of reproduction rate of the CO₂ injection and CO₂ storage (Figures 4.19). Over all, Figure 4.17 demonstrates CO₂ production rates “lb-mole/day” and differences between the two cases. However, there is a slight difference between these two scenarios which is almost invisible in a visual inspection of the plotted lines. Therefore, the difference curve in production rate is also plotted to highlight the difference in CO₂ production due to solubility. Generally, production rate will decline with a reduction in reservoir pressure. As shown in Figure 4.18, CO₂ production rate is higher without solubility (red curve) compare with the solubility case (yellow curve) over the same estimated period of time. The light green curve represents the level of CO₂ reduction when solubility is considered, in other words it represents the production differential between the two above cases. The CO₂ content in the production (yellow curve) starts to increase at a slower rate than the non-solubility case (red curve). The differential starts to decline due to saturation of the formation water with the injected CO₂. Figure 4.19 illustrates the production rate of the injected CO₂ and the differences for the solubility and non-solubility cases. In case there is solubility, during the process of CO₂ injection into the reservoir a smaller amount of the injected CO₂ is produced compared to the non-solubility case. For this case, the ratio of CO₂ to initial methane in place is continuously increasing due to the re-injection of produced CO₂ and the initial CO₂ still unrecoverable in the reservoir. In particular, with solubility more injected CO₂ is stored in the reservoir. That is, the process of CO₂ storage remains attractive unless the production rate of the injected CO₂ remains below the CO₂ injection rate. The higher the CO₂ injection rate the greater volume of CO₂ available in the reservoir to be dissolved due to high potential for CO₂ solubility compared to that of methane. In addition, reasonable CO₂ storage is achieved up to the point where the production rates of the injected CO₂ is still not equal to the injection rate. Thus, the stored volume of CO₂ declines the more the production rate of the injected CO₂ increases (Figure 4.16 and 4.17).

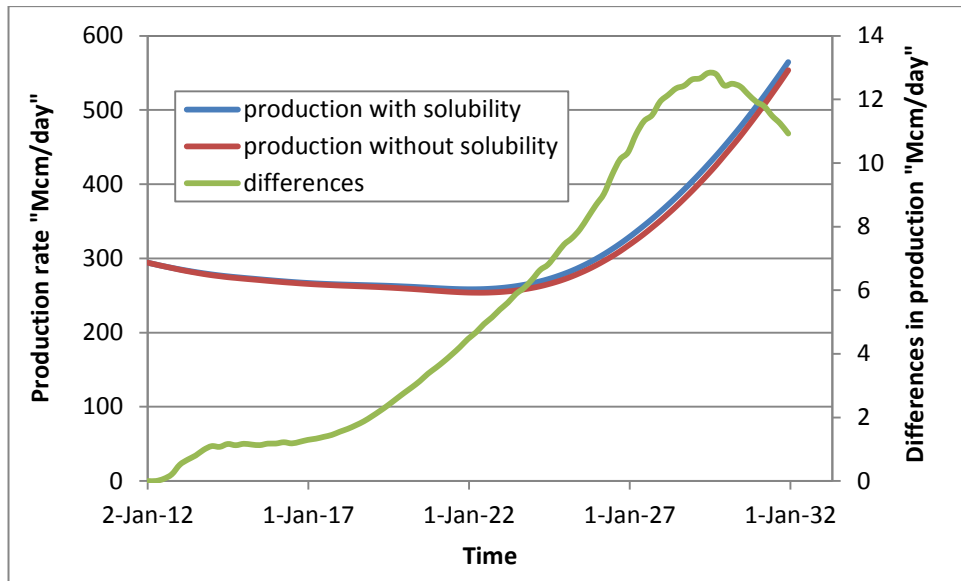


Figure 4.18: CO₂ production rate at high injection rate based on solubility considered and not considered

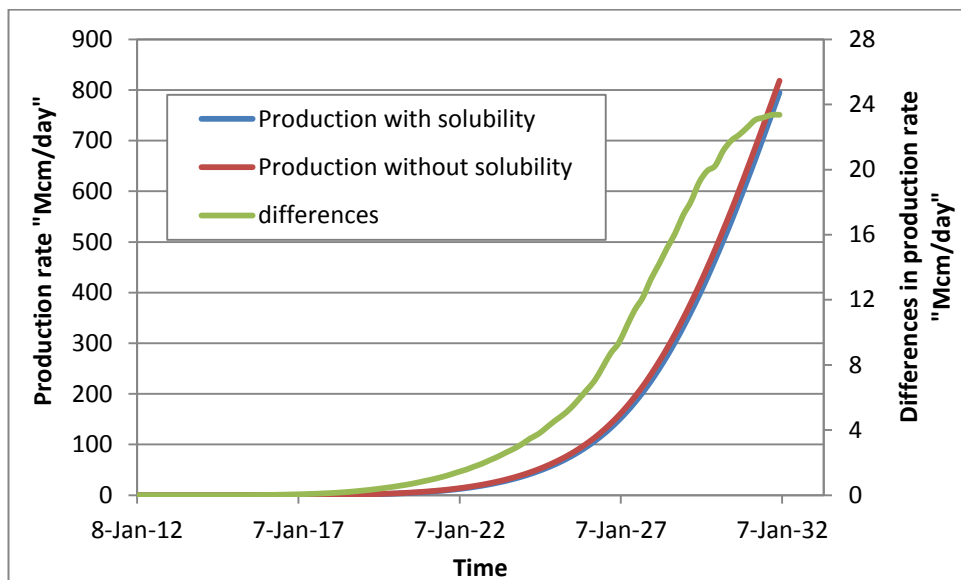


Figure 4.19: Production rate of the injected CO₂ at high injection rate based on solubility considered and not considered

4.4 Results and discussion

The base-case scenario was simulated enabling gas to be produced continuously under normal production conditions. Vertical production and injection wells allocated with different depths with consideration of aquifer zone beneath the gas reservoir. For all the case scenarios, CO₂ injection into the lower portion of the reservoir technically for reservoir re-pressurisation and efficiently sweeps natural gas from bottom layers in the direction toward the production wells, while minimising contamination and gas mixing in the upper parts of the reservoir. Therefore, different

layers were tested for injection purposes as a function of enhanced gas recovery and storage. The arrangement of layers from the top to the bottom of the reservoir “very low, high medium and low” quality presented the highest methane production, CO₂ storage and lowest CO₂ production. This arrangement layers were selected as an optimum scenario to investigate and determine the optimistic case scenario in terms of best injection rate, stage of injection announcement. According to the simulation results, the main obstacles for applying CO₂-EGR and storage are production contamination by CO₂ injection. However, good reservoir management, production control measures and contributions of new technologies could reduce the effects of these problems on the project.

CO₂ injections into the lower portions that represent high permeability of the reservoir and perforate the production wells in the upper part of the reservoir with low permeability are technically feasible due to reservoir re-pressurisation. So here reservoir re-pressurisation could be considered as a support against CO₂ breakthrough, because it could happen before the occurrence of CO₂ breakthrough. The optimal strategy was to take advantage of high viscosity, density and solubility of CO₂, in addition to allocate the injection wells as far as possible from the production well during the process of CO₂ injection. These operational parameters are potentially promising to drive out natural gas from the bottom layers of the reservoir, while minimizing mixing contamination in the upper part of the reservoir. Technically the simulation results indicated that, the higher injection rate of CO₂ can potentially enhance more incremental increases in gas production; however, it will lower the natural gas quality by excessive mixing and early breakthrough creating more CO₂ production.

It is worth mentioning that the initial gas reservoir pressure is high and even though, the production wells are located in the same layer, their completion depths are different. Therefore, we anticipate some compositional gradient due to gravity and temperature effects generated by the depth variation and high density contrast of CO₂ compared to methane. However, the observation of the compositional variation was very minimal. Thus the produced fraction of CO₂ in each well is seen as a straight line from the beginning of production (see Figures 4.7, 4.11 and 4.13). The breakthrough time defined as the time when the injected CO₂ arrived to the production wells. The volume of CO₂ breakthrough was determined as the volume

that exceeded the initial volume of CO₂ that supposed to be produced from the reservoir. Geologically, injection of CO₂ into the aquifer with the depth of 3650 m had strong effects on methane production and CO₂ storage. At this depth, CO₂ acts as a supercritical fluid and would have a density close as to water. As expected, the solubility of the injected CO₂ is reduced when the initial brine of the reservoir is being saturated. As a result, feasibility of CO₂ injection is a function of aquifer depth, low permeability, brine saturation and the distance between the injection and production wells. Figure 4.20 shows the efficient tendency of CO₂ flows downward and stabilises the displacement of the native gas due to its physical properties as a function of the gravitational effects. It is clearly observed that after some period of injection, the reservoir “lower portion” is partially filled with the injected CO₂. The heterogeneity of reservoir preferentially flow CO₂ from the bottom layer toward the production wells as a function of permeability existence for each layer, especially in the second and third layers from bottom of the reservoir (high permeable). Eventually, it will cause breakthrough based on the physical properties of the layers and detrimentally effects enhanced gas recovery with time.

Next, some results for the case scenario are presented when CO₂ injection commenced after 6 years of gas production under normal production conditions. The simulation indicated that the high rate and early stage of CO₂ injection had the highest methane production at the same time it had highest CO₂ production and total CO₂ storage. Time appears to have a significant impact on the planned strategies. It is worthwhile to mention that CO₂ breakthrough occurred at a relatively faster time in comparison with the other two cases under CO₂ injection. The high rate and late stage of CO₂ injection is appeared to be near the optimum strategy. Under this case, more methane is produced compare to that under the base case and low injection strategy. In addition, less time of CO₂ injection “late injection” could have fewer CO₂ costs compared to the early-stage high-injection case. But this case could only be considered when the project is proposed for enhanced gas recovery because it has the highest CO₂ emissions due to late injection and releasing the CO₂ production into the atmosphere before the commencement of injection process. Economically, this will affect the project when carbon tax is considered. As a result of comparisons between the case scenarios, high rate and early stage of CO₂ injection is the optimum and this case can be vital especially when the project is planned for both together, EGR and sequestration. However, the objectives of this research were to investigate

the feasibility of CO₂ re-injection for enhanced gas recovery and storage. In terms of CO₂ production, the low injection strategy is considered to be the candidate for CO₂ re-injection, because with consideration of the native CO₂ production, less additional CO₂ will be required to reach to the desired rate of CO₂ injection. Economically, it will reduce the high costs involved in the process of CO₂ capture and storage compare to the other two cases under higher rate CO₂ injection.

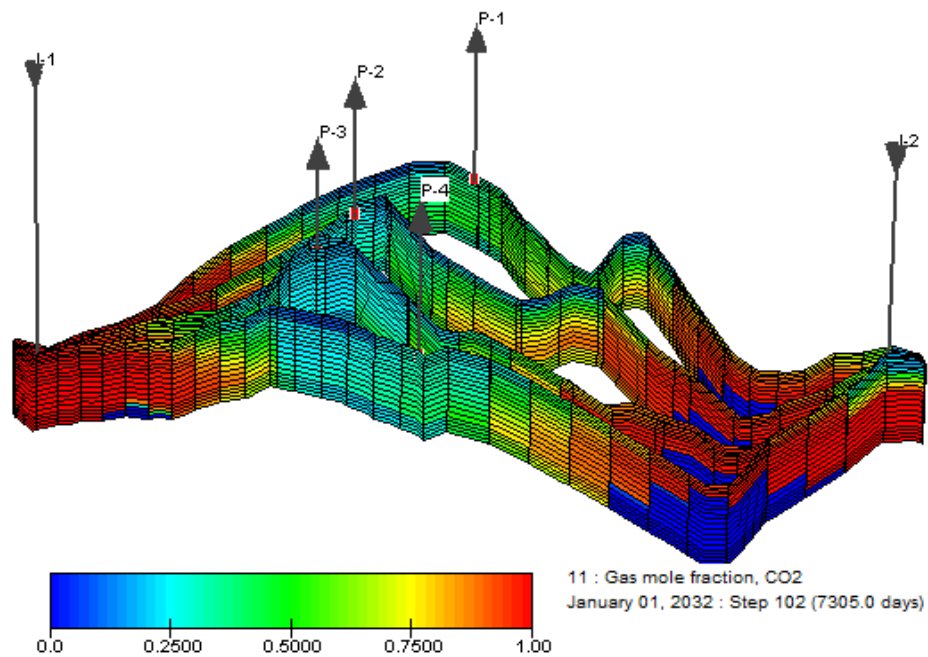


Figure 4.20: Reservoir heterogeneity and CO₂ sweep efficiency

Chapter Five

Techno-economic Reservoir Simulation Model for CO₂ Storage and Enhanced Gas Recovery

5.1 Introduction

An economic model is developed to simulate the development and operation of CO₂-EGR and storage project under various production and injection strategies. This is for the purpose of economically evaluating and comparing the cases and a life cycle cost analysis that will result in a single final value for each case. In order to check the sensitivity of the hypothetical reservoir model and the effect of uncertainty on the results, the case scenarios are assessed under diverse design variables and financial parameters. Such an assessment is useful to understanding the major effective parameters in the economics of CCS-EGR. In addition, a direct carbon tax and carbon credit schemes for CO₂ are considered as a demonstration project for CO₂ storage and as extra financial returns on the project.

5.1.1 General structure of the economic model

All petroleum ventures from exploration to matured field recovery require capital expenditure for generating profits. Investments are usually substantial and require careful and detailed economic study. This chapter will deal mainly with the economics of a field development. The approach is to look at an investment proposal from an operator's point of view. The economic analysis of investment opportunities requires gathering information about capital costs, operating costs, anticipated hydrocarbon production profiles, contract terms, fiscal (tax) structures, forecast gas prices and the timing of the project in the investment. Accordingly, these data are collected from a number of different departments and bodies for instance, petroleum engineering, taxation and legal, host government and each data set associated with a wide range of uncertainty. The economic model for evaluation of investment

opportunities is constructed as a spread sheet, using the techniques to be introduced in the following section.

The uncertainty involved in the model's input data are handled by establishing a sensitivity analysis (Table 5.4), and then investigating the impact of varying the values of key inputs in a sensitivity analysis. From an overall economic viewpoint, it is expected that the project will generate sufficient return on the investment to pay the interest on the capital loans. For instance, the investment opportunity is the development of the reservoir and the cash flow of the project is the tool that incorporates the invested money and the money generated during the project lifetime. Initially, the cash flow is dominated by the CAPEX required to design, construct and commission the hardware for the project. Once the production is commenced, the gross revenues are received from the sale of the hydrocarbons. These revenues are used to recover the CAPEX of the project, to pay for the OPEX of the project, and to provide the host government take which may in the simplest case be in the form of taxes and royalty. The project after-tax share of the net cash flow is then available for repayment of interest on loans, repayment of loan capital and so on. So, from the petroleum company's point of view, the balance of the money absorbed by the project (CAPEX, OPEX) and the profit generated by the project after tax produces the project net cash flow, which can be calculated on an annual basis. It is often referred to simply as the project cash flow.

5.2 Production implementation of the reservoir model

Different approaches adopted in the industry for analysing and evaluating capital investments in the exploration, production, and development of oil and gas fields. In this study, the economic optimization includes competitive production costs which are the ultimate goal of the reservoir management. Accordingly, various reservoir simulation scenarios were performed with consideration of the factors that have effects on CO₂ injection performance. Gas production resulted from these case scenarios are entered on the discounted cash flow (DCF) analysis spread sheets. It involves building multiple scenarios or alternative approaches in order to arrive at the optimum solution. Issues involved in the gas reservoir development include, but are not limited to different production scenarios, enhanced gas recovery project by various CO₂ injection scenarios, well spacing and number of wells, CO₂ storage and

credits. The resulting economic analyses and comparative evaluation of the scenarios can provide the required answers to make the best project decisions. This may lead to the maximum value added to the petroleum asset for given available technology, expected reservoir performance, and market conditions.

5.3 Engineering CO₂ costs aspects and computation

In the manner of the technical feasibility of the reservoir simulation model the following sections explain the techno-economical prospective for each one of the individual components involved in the whole process of CO₂ capture and storage (CCS). There are many options for the separation and capture of CO₂ and some of them commercially available; however, none of them has been applied at the scale required as part of a CO₂ emissions mitigation strategy (David, 2000). In general, the economic model consists of six modules: production costs, capture and separation costs, compression costs, transportation costs, injection costs and carbon credits. As a result, the techno-economic model is subjected to sensitivity analyses to highlight the effects of some parameters on the various economic aspects of CO₂-EGR and storage as a function of the developed gas reservoir mode for given:

- (a) Mass flow rate, this will be estimated through the CO₂ production rate from the gas reservoir model, and also through the required amount of CO₂ capture from the power plant;
- (b) Number of injection and production wells of the reservoir model;
- (c) Depth and completion of the producers and injectors wells; and
- (d) Length of the pipeline for CO₂ from the source to the sink in terms of a location factor (F_L) and a terrain factor (F_L).

The economic models are developed by using collective wide range data which are originally been published by the below sources and are considered to be the best available data at the time to determine the total costs for the process of CO₂-EGR and storage.

- Joint Association Survey on drilling costs “JAS”
- Energy International Administration “EIA”
- Advance Resource International “ARI” based on drilling costs summary data for the United States

These sources initially documented scenarios for water flooding. The scenarios by many published studies were modified for CO₂ injection and used as the base for field equipment and production operation costs. Therefore, the reported data are often used to assess the economic effects of specific plans and policies relating to the industry.

5.3.1 CO₂ capture and separation module

The development of CO₂ capture and separation cost from the power plant to the injection site is based on a study by (David, 2000). In terms of CO₂ injection, despite of the re-injection of CO₂ production, further CO₂ is required to reach the target rate of CO₂ injection for the reservoir model. The additional CO₂ is provided from a nearby NGCC power plant. The power plant has a CO₂ capture efficiency of 0.9.

The system of CO₂ capture requires fuel to generate power and will reduce the net power plant efficiency. Thus, the greater the energy requirement the more fuel is required to operate the system. As a result, the increase in fuel requirement leads to increase and/or cause environmental emissions (IPCC, 2005). David (2000) estimated that the IGCC power plants have less energy penalty and ranged from 10 to 13% during the capture and storage process. In this study, cost of CO₂ capture is assumed to be \$41 (International energy Agency, 2006). Usually, cost of CO₂ capture estimation depends on the technology used in the capture process. Accordingly, absolute cost estimations for CO₂ capture cannot be stated with high degree of certainty.

5.3.2 Compression cost module

McCullum & Ogden (2006) developed a CO₂ compression module. In this study the module is adopted to estimate the capital and operation expenditures of CO₂ compression. In this section the optimum flow rate is determined based on daily CO₂ requirements and/or provided either from the production stream or/and from power plants. The CO₂ requirement prior to transportation need to be compressed to change the condition of CO₂ from gas to liquid state in order to reach the technical and economic condition suitable for transportation (Gusca et al. 2010). In addition, it is necessary to consider the energy requirement for compressing the available volume of CO₂. Under the case of an early injection stage, Figures 5.1 and 5.2 shows the total power requirement for CO₂ compression and pumping power requirement for

increasing the pressure during the compression process under two different case scenarios.

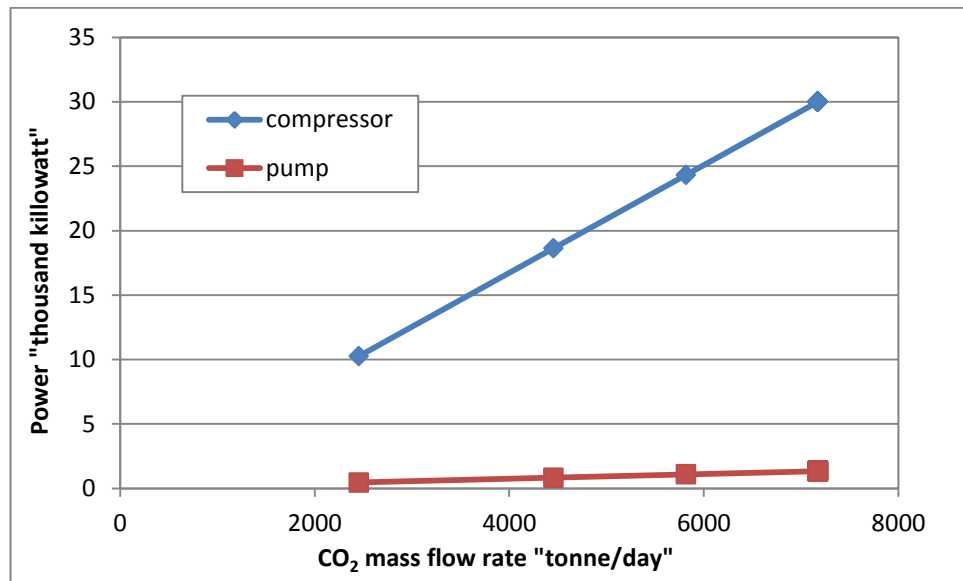


Figure 5.1: Power requirement of compressors and pumps at high injection

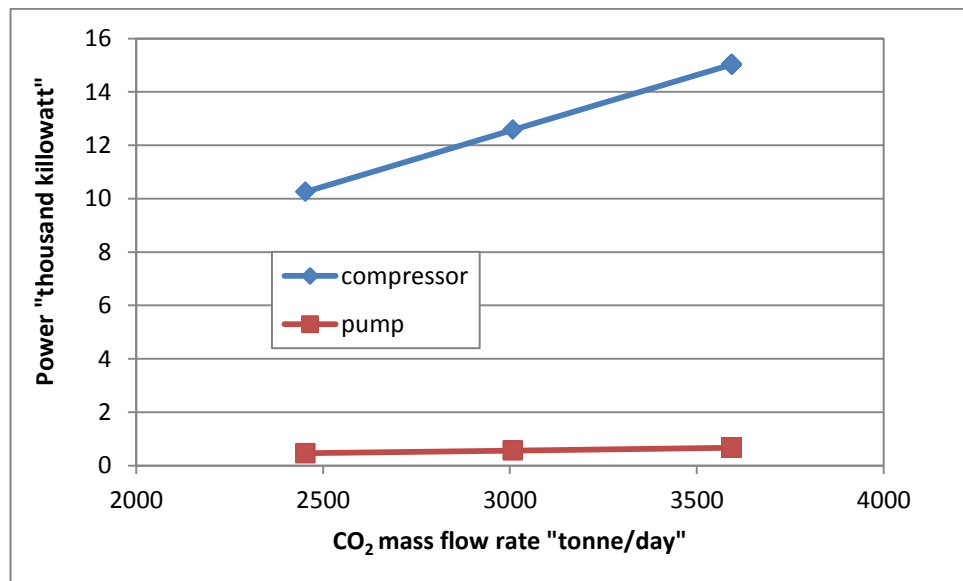


Figure 5.2: Power requirement of compressors and pumps at low injection

The captured and the initial CO₂ production from the gas reservoir compressed with a capacity factor of 0.08 and electricity price is assumed as \$0.065/kWh for each compressor and pump (McCollum & Ogden, 2006). In addition, the capital cost is annualised by a capital recovery factor value of 0.15 and the operating and maintenance cost is by applying an operating and maintenance factor value of 0.04 to the capital cost of compression and pumping (McCollum & Ogden, 2006).

Preliminary site screening and candidate evaluation costs were evaluated by Smith et al. (2002) to be \$330,000 and \$1,355,000, respectively, based on the activities mentioned in Table 2.6. This site characterisation cost originally was estimated by IPCC (2005). This cost value has been adopted for this study as current version for CO₂ capture and storage data preparation.

From an overall compression module viewpoint, Figures 5.3 and 5.4 illustrate capital costs for both compressor and pump (\$/kW) as a function of CO₂ mass flow rate of the reservoir model with the additional CO₂ requirement from the power plant. Accordingly, the total levelised cost of the compressor and the pump (\$/tonne) as a function of mass flow rate tonne/day of the reservoir model is depicted in Figures 5.5 and 5.6 in terms of levelised power, capital and O&M costs.

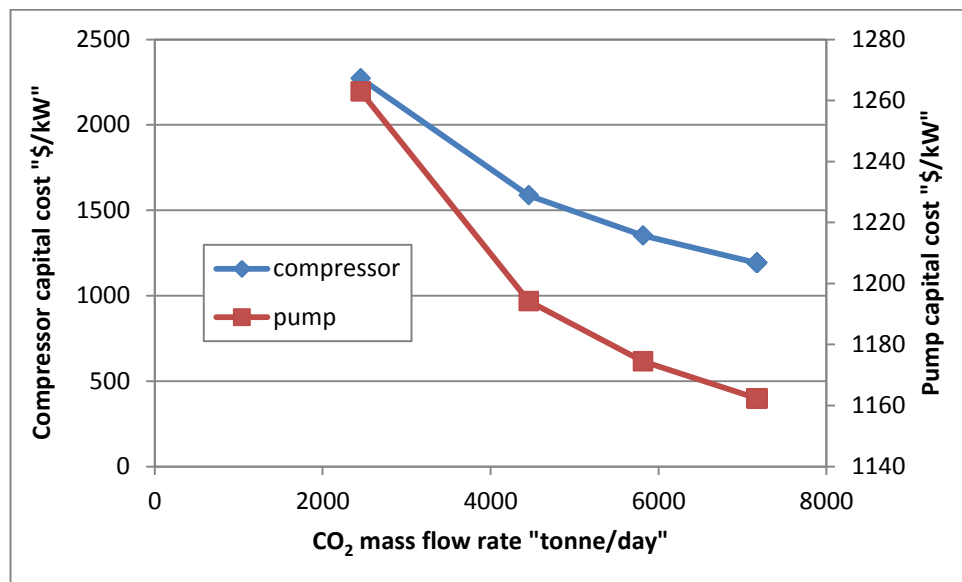


Figure 5.3: Capital costs of compressors and pumps at high injection case

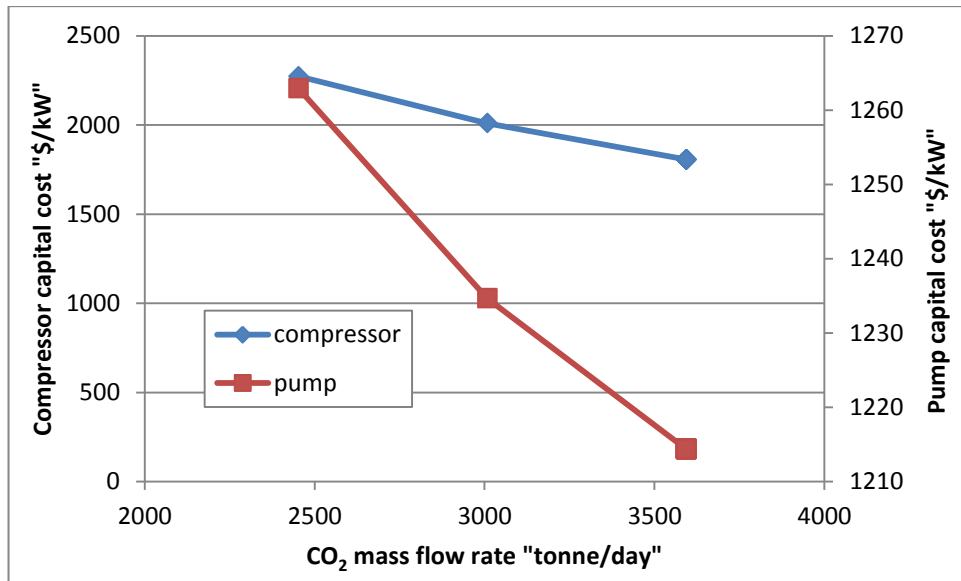


Figure 5.4: Capital costs of compressors and pumps at low injection case

McCollum and Ogden (2006) claim that the maximum size of one compressor train is 40,000 kW. In the original model, the compression power requirement exceeds 40,000 Kw where the volume of CO₂ need to be compressed is around 10,000 tonne per day. In the reservoir model, under both cases the total compression power requirement does not exceed 40,000 kW. Thus, the CO₂ flow rate and power requirement do not need be split into parallel compressor trains. In addition, the more the number of parallel compressor trains the more capital cost is required (see Figures 5.3 and 5.4).

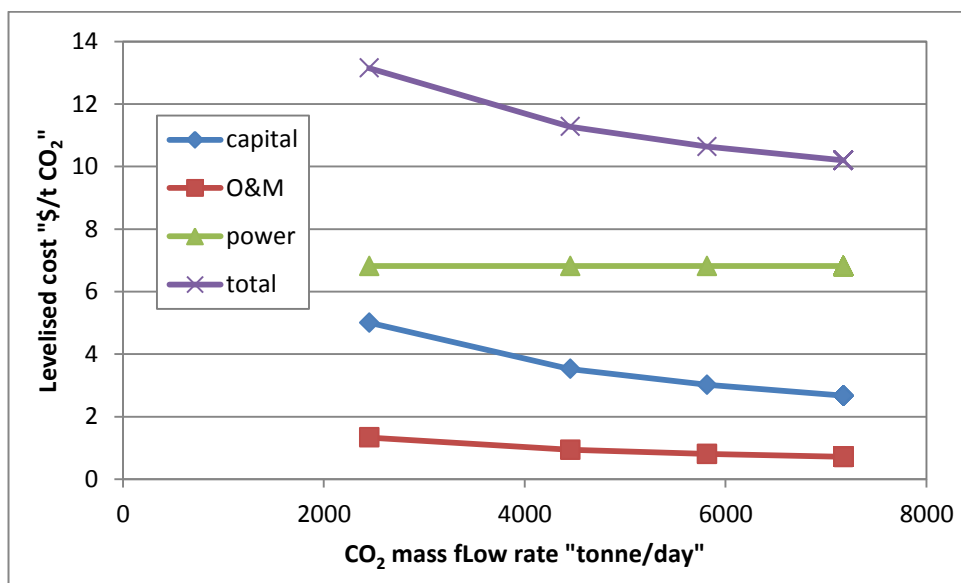


Figure 5.5: levelised cost of CO₂ compression and pumping at high injection case

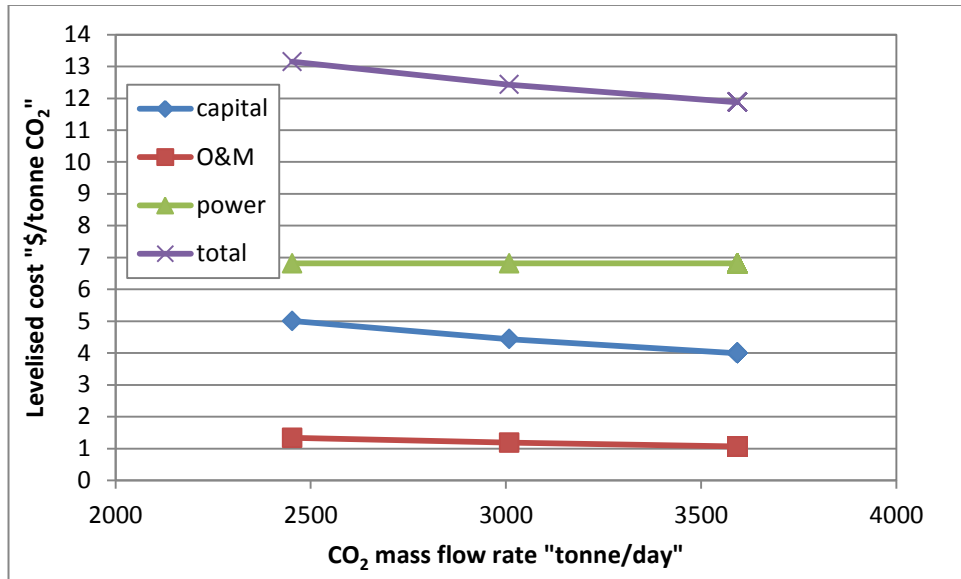


Figure 5.6: Levelised cost of CO₂ compression and pumping at low injection case

5.3.3 Transport cost module

In addition, the compressed CO₂ is transported through the pipeline with the same capacity factor to the injection source. McCollum (2006) studied the similarities and differences among several CO₂ transportation models and developed a new CO₂ pipeline capital cost model that is a function only of CO₂ mass flow rate and pipeline length. In addition, the model avoids pipeline diameter calculation in advance.

The capital cost is annualised by a capital recovery factor value of 0.15 and the operating and maintenance cost is applied by an operating and maintenance factor value of 2.5% to the capital cost (McCollum & Ogden, 2006). The total cost of CO₂ is also ranged up by a location factor and a terrain factor 0.1 and 2.7, respectively a full list of these factors is reported in (Pershad et al. 2010).

From the transportation module, the pipeline capital cost is estimated as functions of mass flow rate and pipeline distance from the source to the sink observed in this research as 100, 200 and 300 km (Figures 5.7, 5.8, 5.9 and 5.10). In addition, levelised costs of transport “\$/tonne of CO₂” are demonstrated in terms of pipeline lengths (see Figures 5.11 and 5.12).

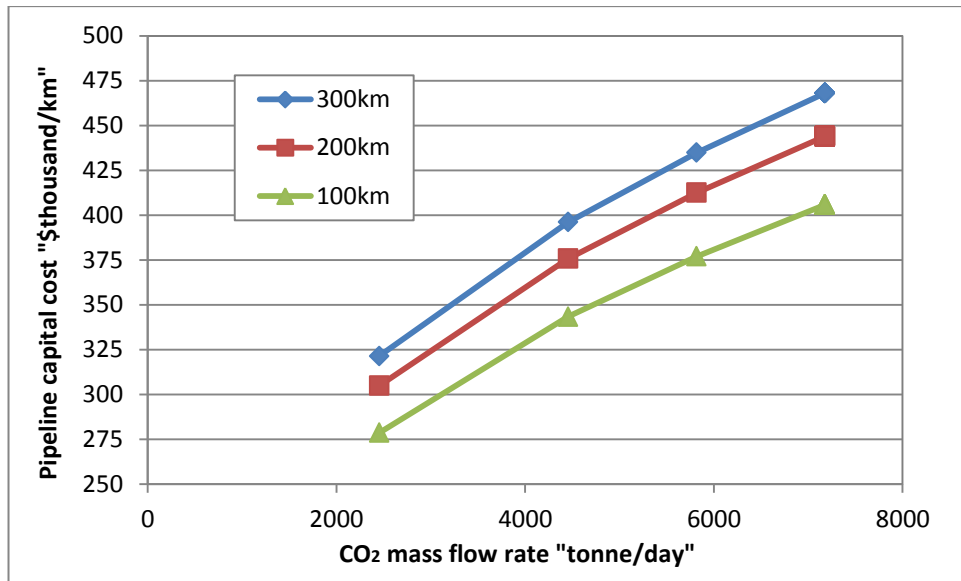


Figure 5.7: Pipeline capital cost as a function of pipeline length at high injection case

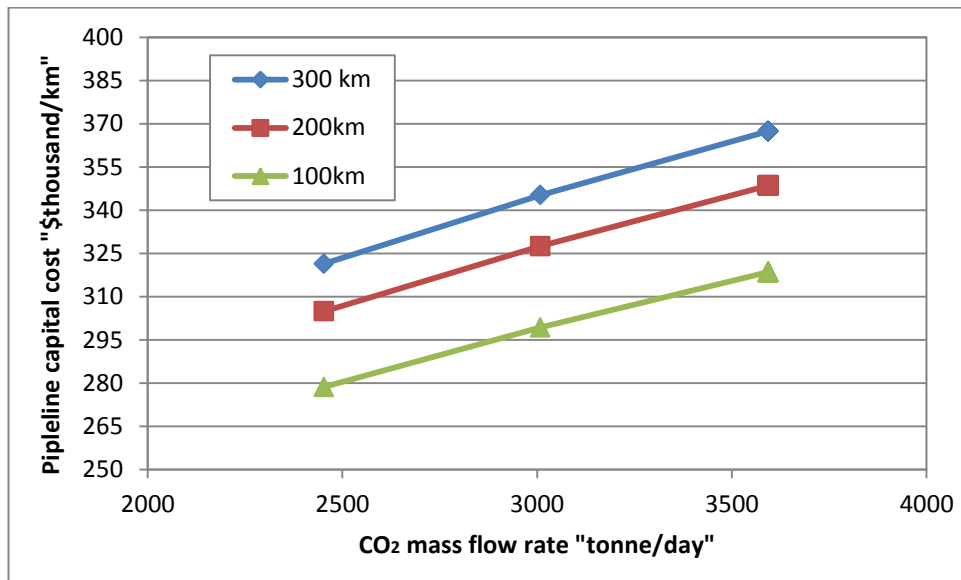


Figure 5.8: Pipeline capital cost as a function of pipeline length at low injection case

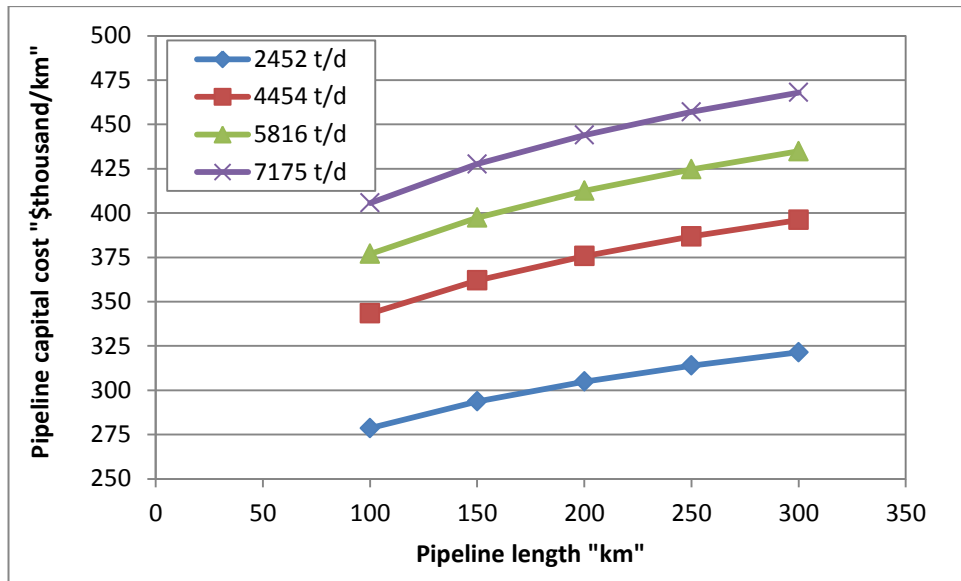


Figure 5.9: Pipeline capital cost as a function of CO₂ mass flow rate at high injection case

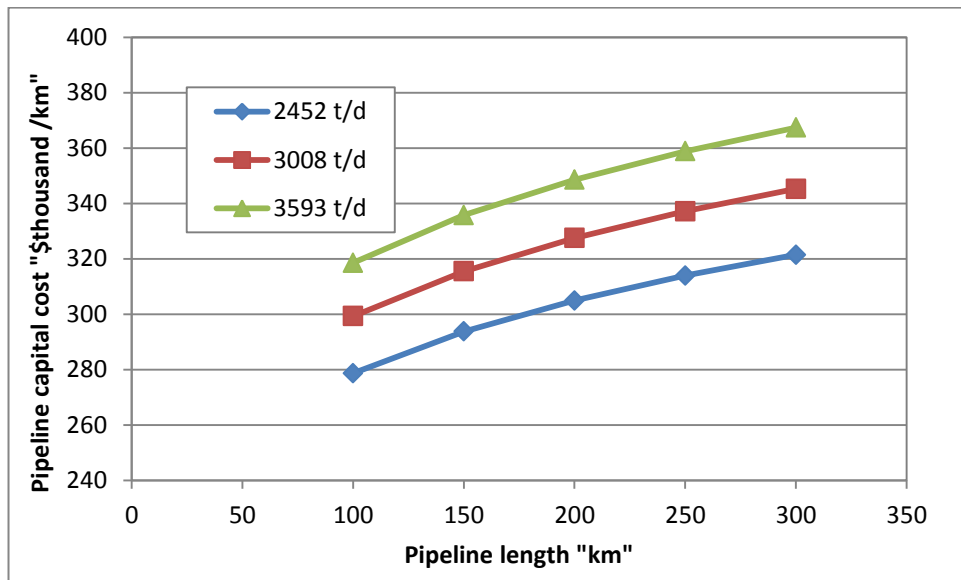


Figure 5.10: Pipeline capital cost as a function of CO₂ mass flow rate at low injection case

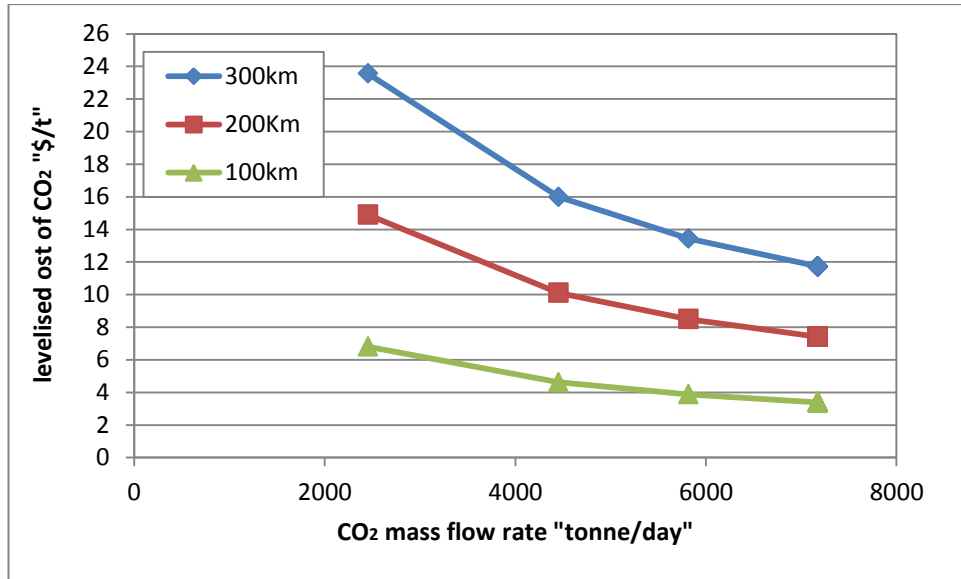


Figure 5.11: Levelised cost of CO₂ transport as a function of pipeline length at high injection case

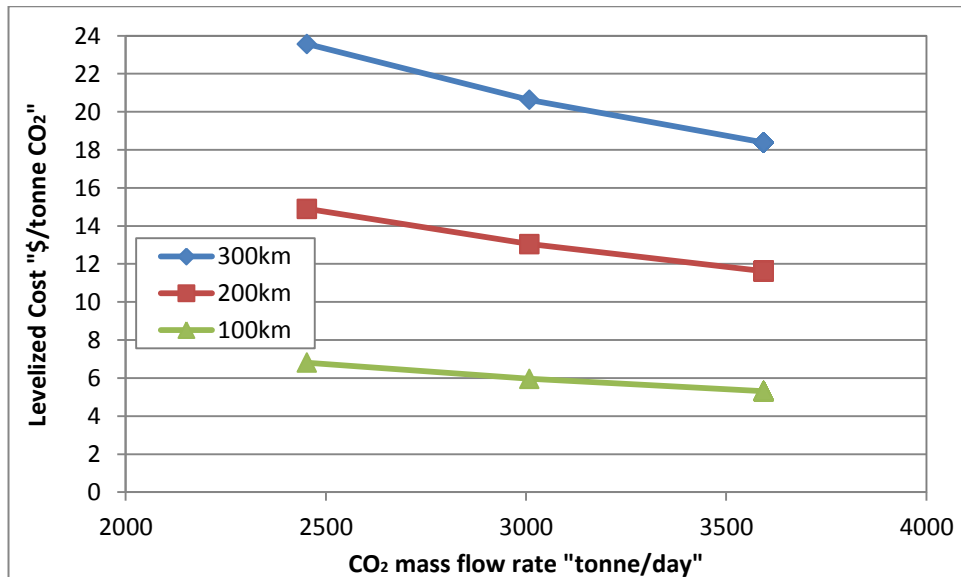


Figure 5.12: Levelised cost of CO₂ transport as a function of pipeline length at low injection case

5.3.4 Injection cost module

Based on the developed CO₂ injection model by IPCC (2005) total CO₂ injection costs is estimated for the hypothetical gas reservoir model a function of site preparation involved in CO₂ injection process, number and depth of wells. The capital cost is annualised by applying a capital recovery factor value of 0.15 and the operating and maintenance cost is calculated by summation of O&M daily, O&M_{consumable}, O&M_{surface} and O&M_{subsurface}. From the injection module, capital, O&M, and equalized costs of CO₂ injection are calculated as a function of number of

wells, mass flow rates of CO₂, and depth of the reservoir. In the first year of costs evaluation the annual capital expenditure is high due to capital cost of site preparation and evaluation “C_{site}”, and the capital cost for drilling of the wells “C_{drilling}”. Then it declines sharply due to not considering C_{site} and C_{drilling} costs in the next following years of the project evaluation.

Furthermore, the annual capital cost starts to increase slightly as a function of the given CO₂ injection rates (Figures 5.13 and 5.14). Once the injection rate of CO₂ is ramped up to the desired injection rate, the capital cost is stabilised for the rest of the remaining life of the project evaluation. In this stage the only remaining cost involved in the annual capital cost calculation is the capital cost of injection equipment “\$” which is a function of the number of wells and CO₂ injection rate.

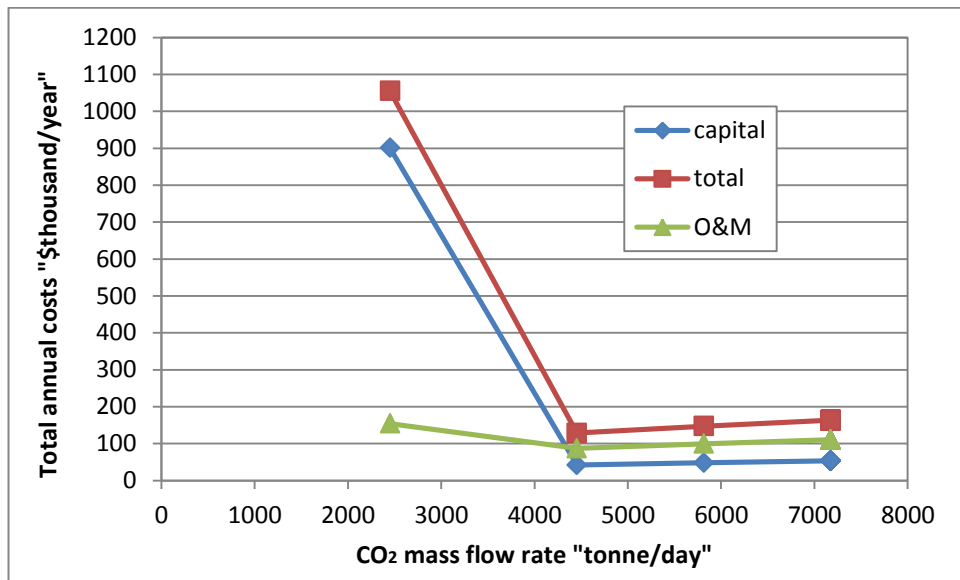


Figure 5.13: Total annual cost of CO₂ injection at high injection case

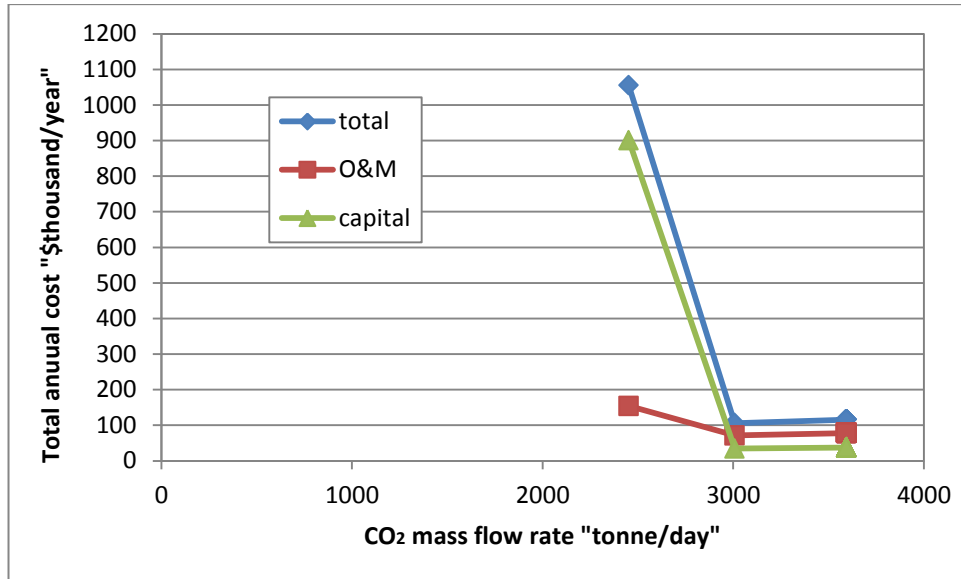


Figure 5.14: Total annual cost of CO₂ injecting at low injection case

The same scenario is applied for annual O&M costs. From the commencement of evaluation the annual O&M cost is high due to normal daily expenses, consumables O&M expenses, and subsurface maintenance expenses. In following years, it declines slightly and stabilises as function O&M expenses due to surface maintenance (see Figures 5.13 and 5.14).

Costs of CO₂ processing are evaluated under the case of late injection stage (see Tables 5.2 and 5.3). From Figure 4.17, the commencement of CO₂ injection rate starts in March 27, 2017. In terms of the high injection rate for the two cases, however, the commencement of CO₂ injection begins at different time. Under late-stage injection, the injected CO₂ reaches the target rate of the injection after a few months, as under early-stage injection. At this point the CO₂ compression cost, transport and injection in the first case at high injection are similar with second case for the life of the project, except for the capture and separation costs from the power plant and the production stream.

Even though, there is no injection in the beginning of gas production, there is still some production cost such as capital cost of site preparation “C_{site}”, and the capital cost for drilling and completion costs of the production wells, lease equipment costs for production wells, annual O&M costs and converting the existing production well into injection well, after the commencement of CO₂ injection especially when CO₂ concentration in well number 2 reaches to 10%. These costs are also used for evaluating case scenario one as production costs. Based on the cost modules, which

originally have been developed by Advance Resource International, in this section these modules have been adopted to estimate the production costs for the reservoir model. Overall, the cost calculation depends on the number of production wells and depth of the wells.

Table 5.1: Production costs estimation for the cases as a function of production well

Well Drilling and Completion Cost \$/ft			
Well 1	Well 2	Well 3	Well 4
1,029,378	1,055,936	1,038,171	1,125,755
Production Well Equipment Cost \$/ft			
Well 1	Well 2	Well 3	Well 4
165,876	167,466	166,404	171,594
Cost of Converting the Existing Production Well into Injection Well			
Well 1	Well 2	Well 3	Well 4
-	-	-	106,029

5.3.5 Introduction of carbon credits

To make the CO₂-EGR and storage process economically attractive, and to consider Greenhouse Gas Emission reductions, the cost involved in the process need to be lowered, higher gas price or carbon credits included. Currently, CO₂ capture and storage technology CCS cost estimates are very high. Accordingly, this technology is unlikely to be put into practice effectively without any financial motivation or tax incentives. Economically, CO₂-EGR and storage becomes more feasible if it is combined with the process of CO₂ capture and storage, this is due re-injection of the native CO₂ production into the reservoir and may result in less CO₂ being required from other source or producers (International Energy Agency 2010).

Overall, the concept of CO₂ storage from the same source potentially provides a reasonable structure for carbon credit to be fully developed during the process of CO₂-EGR and storage. In particular, CO₂ capture and separation systems and storage (compression, transportation and injection) systems are considered as an emission reduction approach (Nguyen 2003). A credit for emission reduction is reduced by producing additional CO₂ per ton injected; possibly released into the atmosphere during the CO₂ storage process. This process (CO₂-EGR) is likely to occur in the context of carbon credit schemes and development of low value emissions. Worldwide, the idea of carbon credit has been around, but not been put into practice despite extensive coverage and political positioning. Here, the concept of net value

of carbon credits is expressed as a function of carbon credit (the money received for CO₂ storage) and carbon tax (the money paid for CO₂ emission). The first part of Equation (5.1) shows the storage of the injected CO₂ and multiplied by the carbon credit. This will estimate the received price for per tonne of CO₂ storage.

$$\begin{aligned} \text{net value of carbon credit} \\ &= [\text{injected CO}_2 \text{ into reservoir}] - [\text{CO}_2 \text{ produced from the reservoir}] \\ &\quad - [\text{CO}_2 \text{ emission}] \end{aligned}$$

Injected CO₂ into the reservoir is the injection rate (m³/year). CO₂ produced from the reservoir (m³/year) is the difference between the injected CO₂ (m³/year) and production rate of the injected CO₂ (m³/year). This in turn estimates CO₂ storage (m³/year). Once storage of the injected CO₂ is estimated and multiplied by carbon credit (\$/tonne) will result in the price received for storing CO₂. CO₂ emission (\$/tonne) is estimated by multiplying energy penalty (%) by the emitted amount of CO₂ (tonne/year) into the atmosphere during the process of storage and enhanced gas recovery. Accordingly, net value of carbon credit is estimated to illustrate the feasibility of a project (CO₂-EGR) when carbon credit is considered.

The Figures 14.16 and 4.17 show CO₂ injection rate and storage per tonne of CO₂ under different case scenarios. Based on current literature, large variations in unit of CO₂ energy penalty or the energy burnt and released into the atmosphere are mentioned, and range from 9.0 to 15.0% by the technology employed for CO₂ separation and the type of the power plant (David 2000). As a result, and considering the energy penalty % through Figures 14.16 and 4.17, emissions per tonne of CO₂ injection are considered during the process of CO₂ capture and sequestration. If carbon credit markets are introduced in a significant way, the reduction of one ton of CO₂ fossil emissions by either by preventing it from entering the atmosphere (natural gas reservoir) or by extracting it from the atmosphere. The storage site will represent an additional source of revenue and the CO₂ emissions represent an additional cost. We estimate that the difference between them represent net carbon credit. If future CO₂ markets involve effective payment for CO₂ storage compared to carbon tax for CO₂ emission, the introduction of a carbon credit scheme can be considered as additional source of revenue or the re-injection cost recovery. Optimistically, the economic feasibility for CO₂-EGR and storage becomes more attractive (Oldenburg et al. 2004).

Table 5.2: Total CO₂ capture and compression costs under different cases

Case-1- Scenario of early injection at low rate of CO ₂			
Capture \$	Total Compression Cost \$		
	CAPEX	OPEX	Electricity
641 million	85.9 million	229 million	154 million
Case-1- Scenario of early injection at high rate of CO ₂			
Capture \$	Total Compression Cost \$		
	CAPEX	OPEX	Electricity
1,230 million	107 million	29 million	263 million
Case-2- Late stage of injection at high rate of CO ₂			
Capture \$	Total Compression Cost \$		
	CAPEX	OPEX	Electricity
1,140 million	73 million	19 million	185 million

Table 5.3: Total CO₂ transportation and injection costs under different cases

Case-1- Scenario of early injection at low rate of CO ₂			
Total Transport Cost \$		Total Injection Cost \$	
OPEX	CAPEX	OPEX	CAPEX
36 million	213 million	1.7 million	1.6 million
Case-1- Scenario of early injection at high rate of CO ₂			
Total Transport Cost \$		Total Injection Cost \$	
OPEX	CAPEX	OPEX	CAPEX
43 million	256 million	2.2 million	1.9 million
Case-2- Late stage of injection at high rate of CO ₂			
Total Transportation Cost \$		Total Injection Cost \$	
OPEX	CAPEX	OPEX	CAPEX
29 million	173 million	1.5 million	1.6 million

5.3.6 Prediction of future price

In real-world determining the future market price of hydrocarbon is a challenging task due to its unpredictable volatility (Gharbi, 2001). To deal with this task, most studies consider the wellhead gas price as a constant value from 3 to 5 \$/Mcf for calculating net present value of a project (Jikich et al. 2004; Oldenburg et al. 2004; Hussen et al. 2012). However, this scenario does not enable project evaluations when the future price changes. Some studies use risk analysis and predict future price changes by using a certain percentage. But future determination for this percentage is difficult due to the effects of unpredictable future occurrences. Company's future contracts price is another existing scenario to evaluate a project's future evaluation. In this scenario companies evaluate projects based on the contract for a fixed price for a certain time frame.

Even though, there are risks, a fixed price for a certain time is accepted as a common approach for the future hydrocarbon price. Usually the time frame for this type of contract is limited to six years, and petroleum prices change regularly and substantially through time (Uzoh et al. 2010). Therefore, here the long-term annual wellhead gas price is assumed equal to the average well-head price for natural gas as per the EIA annual energy outlook (Energy Information Administration, 2012). The initial forecast is for 2012-2035. Because the gas reservoir simulation model is evaluated for 2012-2032, the future gas prices for this time are estimated from 3.4 up to 5.8 \$/Mcf, respectively (Figure 5.15). This estimation initially is performed by the Henry Hub natural gas prior settled future price. This range is close to those that have been mentioned in the literature as a constant price value for project evaluation.

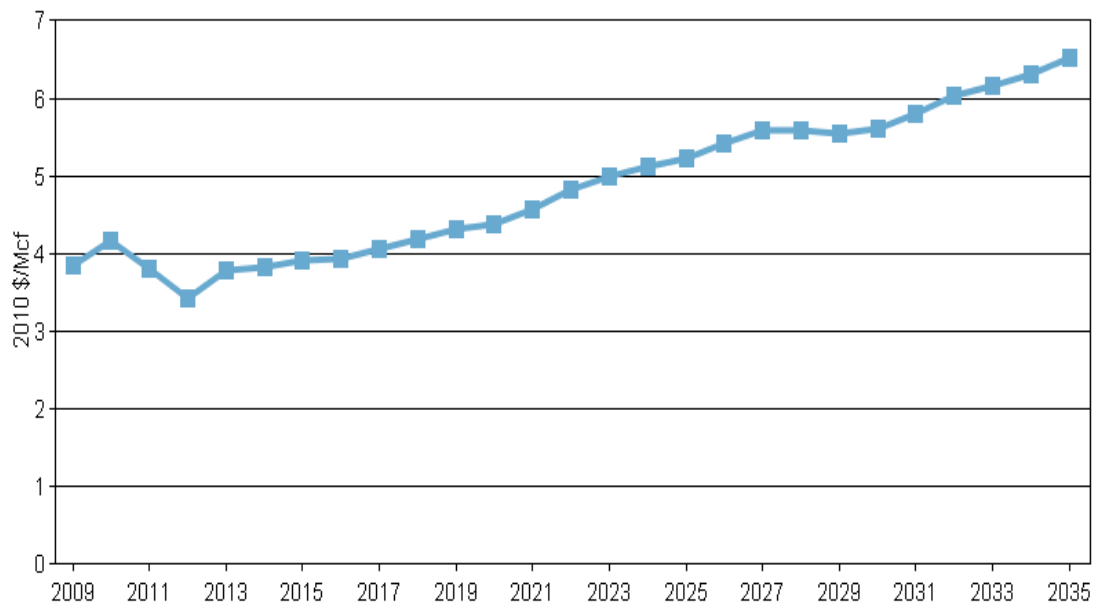


Figure 5.15: Gas well head price. Source "U.S. EIA, 2012"

5.4 Discounted cash flow

Discounted cash flow analysis is a method widely used as an economic criterion to evaluate investment proposals. Future cash flows are estimated as the difference between all the cash-in 'expenses' and all the cash-out in the future. Cash flow with considering time and discount rate will yield discounted cash flow and the summation of discounted cash flow is the net present value of a project (Uzoh et al. 2010). This approach is used to evaluate the case scenarios for CO₂-EGR and storage under alternative investments (Figure 5.16).

The three cases to be evaluated are defined below and economic evaluation for each case constructed as illustrated in Table 5.16:

- Base case; continue primary production process;
- Carbon dioxide solvent miscible injection case scenarios for implementing EGR and storage under two different injection rates; and
- Late-stage of solvent miscible injection at high case scenario.

First, assume that all produced natural gas from the reservoir model can be sold according to the estimated natural gas wellhead price from EIA. In this stage the natural gas is the only revenue considered. In addition, this revenue is deducted from all the expenses and then calculated with net carbon credits as second revenue before discounted by annual discount rate.

The estimated cost of CO₂ separation from production stream is assumed at rates of \$/tonne flow rate for re-injection purposes. This cost element plays an important role in the economic evaluation. Under injection cases, the more CO₂ re-injection from the production stream the lessen addition CO₂ is required from the power plants to reach the target rate of injection, the same play between these two opposite forces in terms of cost.

Table 5.4: Fiscal and economic parameter for sensitivity analysis

Uncertain Values	Scenario			References
	a	b	c	
	CO ₂ separation \$/t	3	5.2	
CO ₂ emission %	10	15	25	David, 2000
Carbon price \$/t	1	10	20	Springer, 2003
Carbon tax \$/t	0	20	23	Commonwealth of Australia, 2011
Royalty %	11	12.5	15	Gharbi, 2001; Paidin et.al 2010
Income tax %	20	25	30	Paidin et.al 2010; Gharbi, 2001
Discount rate %	11	13	15	Ghomian ed.al 2008

In this study, sensitivity analysis for seven parameters are considered to illustrate the effect of changing any economic parameters involved in the three cases based on some assumptions elements and the source of the values are initially extracted from

current literature studies in order to perform a comprehensive sensitivity analysis for diverse net present calculations (see Table 5.4).

Since the cost chain of production, capture, compression, transportation and injection have been calculated for the reservoir model. A summary of the modules is provided in Tables 5.2 and 5.3. These costs are considered for net present value calculation in the discounted cash flow for the reservoir evaluation. Note that actual costs in terms of CO₂ storage are different for each case scenario. DCF analysis is performed for each case scenario to find out the best effective parameters involved in the project evaluation and then compare the results to provide economic suggestions. The diagram below is the economic model for CO₂-EGR and storage used in this study. The excel spread sheet format is developed based on the concept of this diagram to illustrate the sensitivity analysis.

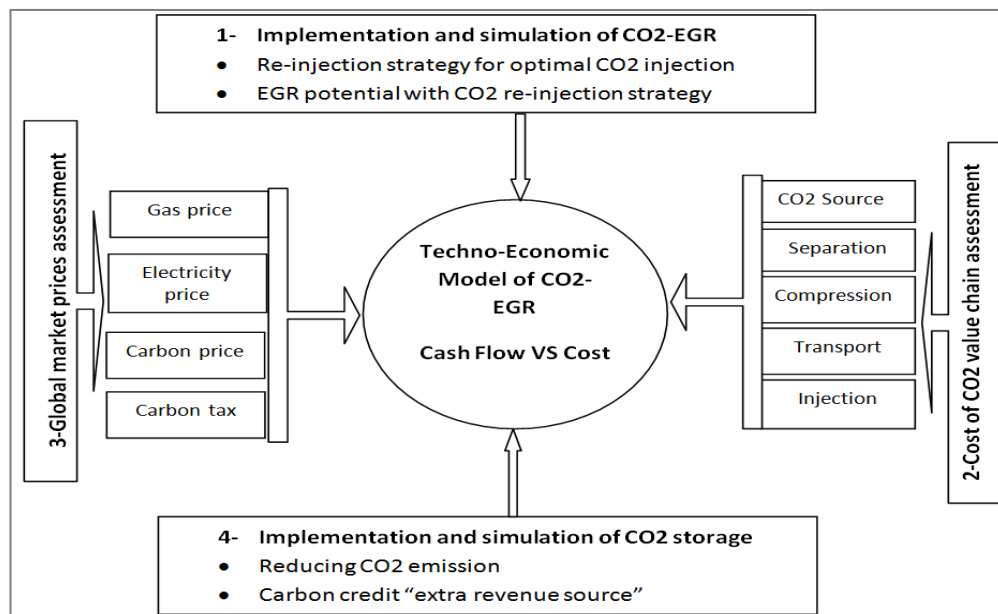


Figure 5.16: General structure of the economic model of CO₂-EGR and storage

5.5 Economic for case scenarios and comparison

The following sections present the economic analysis used to evaluate the feasibility of enhanced gas recovery and sequestration. This application is based on combinations of the reservoir parameters as a performance model obtained by using the compositional reservoir simulation temperst and economic factors from the techno-economic modules and updated for the gas reservoir model in terms of its particular features such as mass flow rate of CO₂, depth of the reservoir, number of

the injection wells and length of the pipeline from the source to the injection site. Where a miscible CO₂ injection technique is implemented to enhance and increase incremental gas recovery from project initiation. After considering the basic components of the cash flow, the model is applied to the developed gas reservoir. The actual gas recovery estimates differ by injection strategy. The economic feasibility for the sample gas reservoir depends on the incremental benefits of gas recovery relatively to the incremental expenses of CO₂-EGR. Cumulative discounted cash flow curves are demonstrated for the case scenarios with and without net carbon credit consideration to achieve a comprehensive understanding of the financial of the project. Even though, the model is subject to sensitivity analysis, effects of these parameters on economic aspects of CO₂-EGR project are subject to high degree of uncertainty.

5.5.1 Base case, continue primary production process

(The production data obtained from the simulations are applied to the economic criteria to evaluate the project feasibility. Economic feasibility is used as a basis to compare cases designed to optimize gas production under particular scenario. Calculations are based on natural gas recovery and 9% of CO₂ in the gas reservoir. Base methane recovery with no enhanced mechanisms totalled (14,494 MMcm) recovery with CO₂ vented into the atmosphere totalled (1,494 MMcm) over the lifetime of the reservoir. Considering wellhead prices for pipeline gas sales and the cost of drilling the production wells as the conventional production costs phase (see Table 5.5) and the other fiscal parameters mentioned in Table 5.4 resulted in the estimation of discounted cash flows for scenarios a, b, and c.

Table 5.5: Wells production costs

Start-up Costs	Number of Well	Total Cost "Million US\$"
Production well D&C cost	4	4.249
Production well equipment cost	4	0.671
Injection well conversion costs	1	0.106
Total costs	\$5.027 million	

However, the total costs of production wells are considered for all scenarios, however the costs of injecting wells are not considered. In addition, carbon tax for venting the separated CO₂ into the atmosphere is estimated at (\$0, \$84.6 million, and \$195 million) for scenarios a, b, and c, respectively. As a result, the below figures

show the cumulative discounted cash flow and the effects of carbon tax on the project where the implementation of carbon credit scheme.

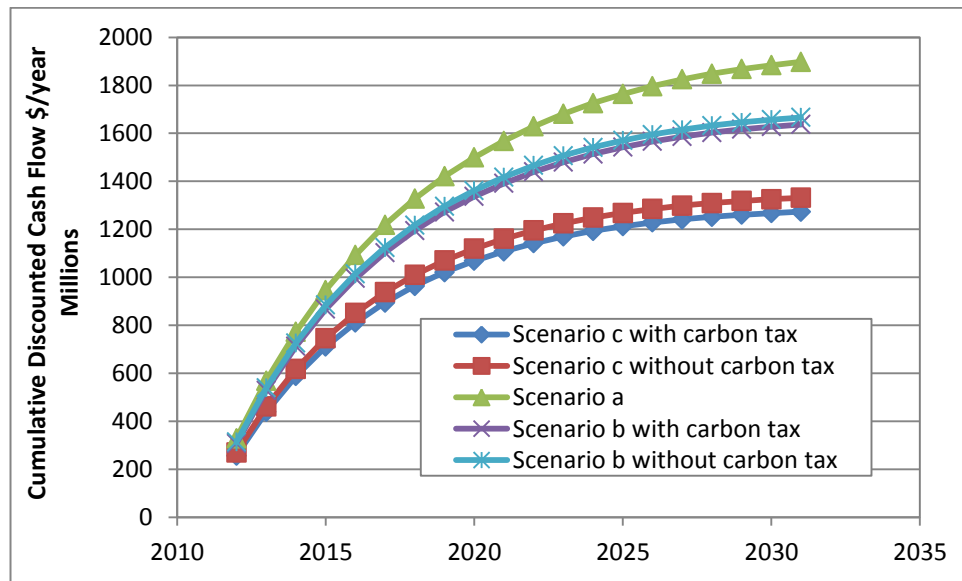


Figure 5.17: Cumulative discounted cash flow under the base-case as a function of carbon tax

5.5.2 Case scenarios under solvent miscible injection

Economic feasibility of CO₂ injection into gas reservoirs for enhanced gas recovery and storage are investigated through Figures 5.18, 5.19 and 5.20. The enhanced gas recovery project assumes wells are located at three distances (100, 200 and 300 km) from the capture source. According to section 5.2.3, the longer is length of the pipeline the more costly is CO₂ transport. Accordingly, only the 200 km pipeline length is used as a distance from the source to the injection site during the economic analysis. In this technique, the additional CO₂ from the power plant and CO₂ production from the gas reservoir are injected at supercritical conditions into the gas reservoir, initially through two injection wells. Gas production rates since the initiation of the project were estimated under various strategies (see Chapter 4) and the costs of EGR and storage for each case were estimated based on the techno-economic modules as a part of the overall cash flow analysis (see Table 4.5). Predictions of CO₂ injection performance and storage of injected CO₂ are crucial for detailed economic analysis. The cash flow analysis is a reflection of the petroleum fiscal parameters. The discounted cash flow for the CO₂ injection for enhanced gas recovery and storage is estimated based on the following economic criteria, revenue from selling natural gas production, revenue for possible CO₂ credits from storage

site, project costs such as site preparation and evaluation constant costs, O&M and capital expenditure as a function of the reservoir model. In addition, governments take such as income tax, royalty and carbon tax on CO₂ injection.

Net present value calculations of the project are also performed under late CO₂ injection technique after taxable income, royalty, discount rate and gas price as mentioned in Table 5.4. Overall, at the initiation of the project costs are high. In addition, later in the project the costs start to decline prior to the commencement of CO₂ injection.

After the occurrence of CO₂ breakthrough, costs started to increase especially due to costs of CO₂ capture. Due to reservoir management and production control measures, the last case has lower costs than the first scenario in the first case for the whole project life. This is due to lower the additional CO₂ required, lower volume of CO₂ injection, less volume of CO₂ production to be separated as market preparation.

Similarly, the net present value of the project is calculated in terms of carbon credit as credit for CO₂ storage and it has been compared with same net present value when carbon credit is not considered, to predict the credible case of the project (Figures 5.18, 5.19 and 5.20). Results show that net present value of the case scenarios is higher where net carbon credit is accounted for. Overall, the low-injection case is more favourable to compare the first and last cases.

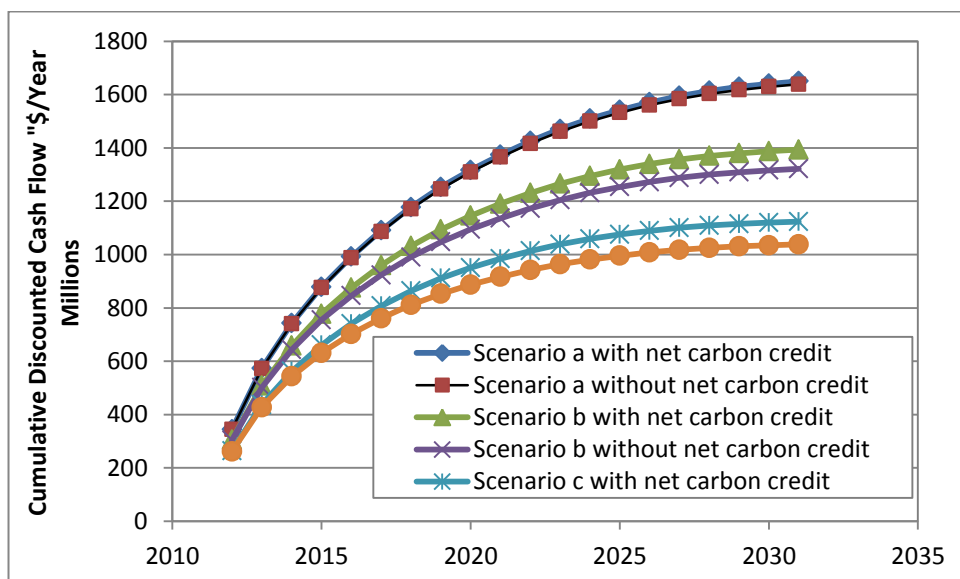


Figure 5.18: Cumulative discounted cash flow under high case injection as a function of carbon tax

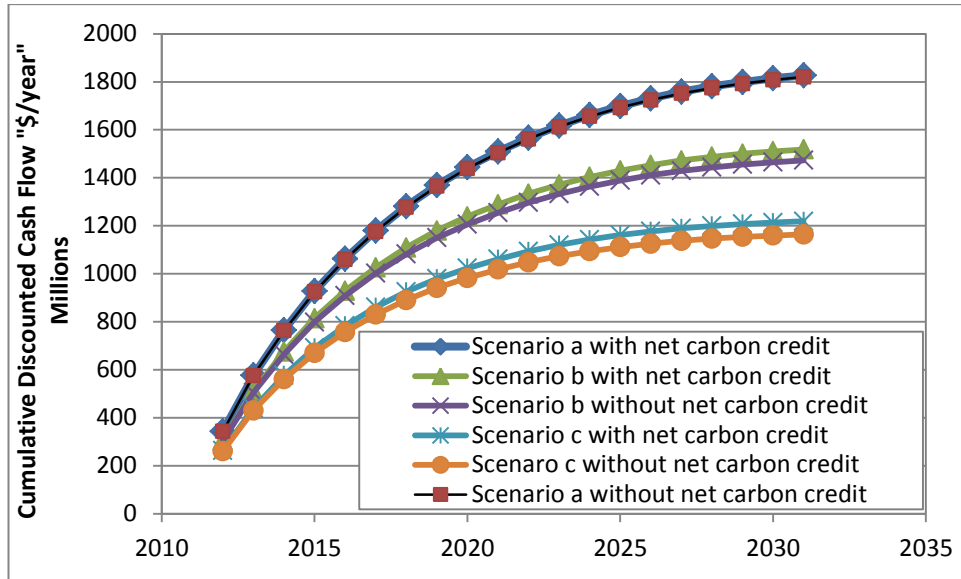


Figure 5.19: Cumulative discounted cash flow under low case injection as a function of carbon tax

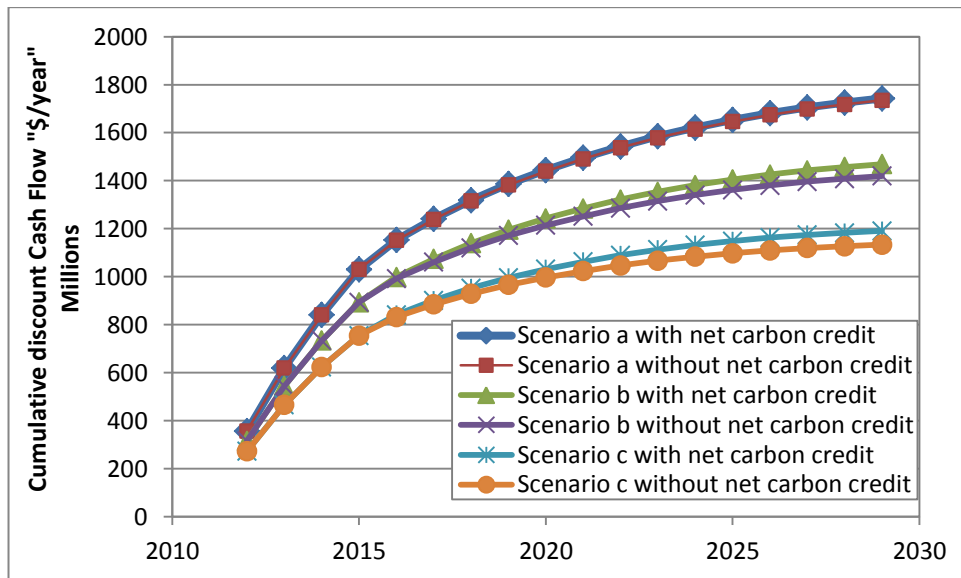


Figure 5.20: Cumulative discounted cash flow under late stage of injection as a function of carbon tax

5.6 Results and discussions

Clearly, the high cost of CO₂ capture and storage and low price of natural gas is a barrier to implementing this technology. In this study, the estimated price is high enough to achieve the economic feasibility under current process and the gas field technology. A fundamental assumption concerns the volumes occupied by the initial produced natural gas. This potentially becomes available for storing the injected CO₂. Therefore, the technique of CO₂ injection provides added values in terms of the incremental gas recovery otherwise cannot be recovered and credits for sequestering the injected CO₂ in the volumes originally taken by the produced gas. In this manner,

the introduction of emission trading mechanism would provide positive effects on promoting the technology of CO₂ injection for enhanced gas recovery and storage.

Clearly, gas recovery factor for the base-case is lower than those under the other cases. The net present value before net carbon credit consideration is \$ (\$1,900 million, \$1,670 million, and \$1,330 million) for scenario a, b, and c, respectively according to the fiscal and economic parameter in tables 5.2, 5.3 and 5.4. Whereas, the same net present values with considering the concept of net carbon credit as a carbon tax are low due to the released CO₂ production into the atmosphere. In addition, a comparative analysis of net present values magnitude for three possible scenarios “a, b and c” with and without considering carbon tax are depicted.

Clearly, the gas recovery factor for the high-injection case is greater than that for low- and late-injection cases. The simulation results indicate that the CO₂ injection rate can enhance incremental increases in gas production. However, it will also lower the gas quality by excessive mixing, as early breakthrough produces more CO₂ production. Figure 5.21 and Figure 5.22 show cumulative CO₂ production for alternative cases. The simulation indicates that higher the CO₂ injection rates result in more gas production, and at a faster rate. Under late-stage injection, from the beginning methane production rates are similar to those under normal production conditions. After CO₂ injection, methane production increases (initially low-injection rate) and in time exceeds the low injection rate.

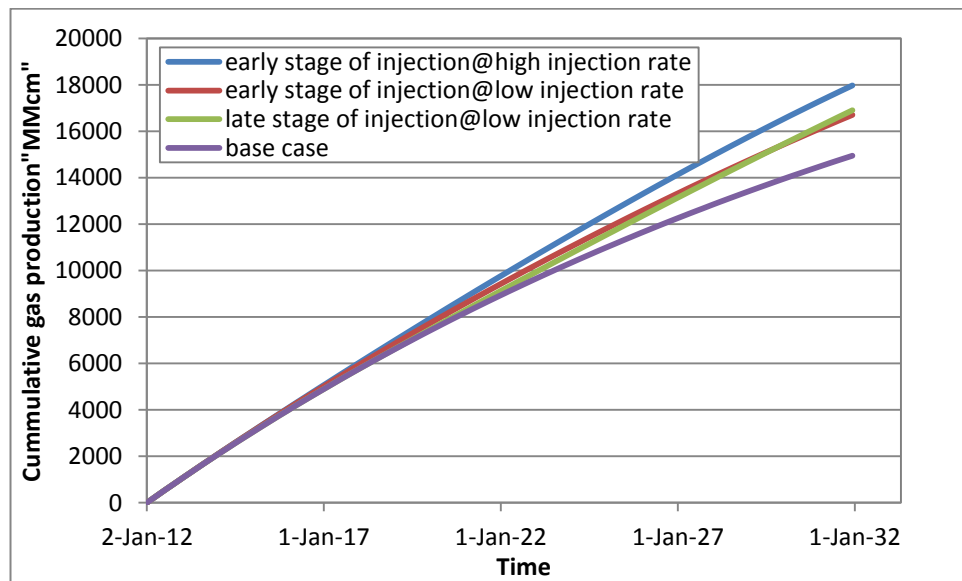


Figure 5.21: Cumulative methane production under various case scenarios

Cost-wise, there is a direct link between methane and CO₂ production. In general, the cost of CO₂ capture declines through time after CO₂ breakthrough occurs. Conversely, CO₂ separation costs continuously increase through time due to CO₂ breakthrough.

Establishing an economic case for EGR is more difficult when natural gas production is contaminated with CO₂. That is, as the injected CO₂ passes through the most permeable reservoir layers, gas production becomes more contaminated. Since CO₂ concentration, on average, exceeds 0.09, the CO₂ production rate increases. This production increase substantially increases the cost of CO₂ during CO-EGR and storage evaluation. Also, CO₂ emissions must be considered as an additional cost associated with energy use during CO₂ injection for enhanced gas recovery and storage. The emission cost depend emission rates and carbon tax for the CO₂ injection mass flow rates.

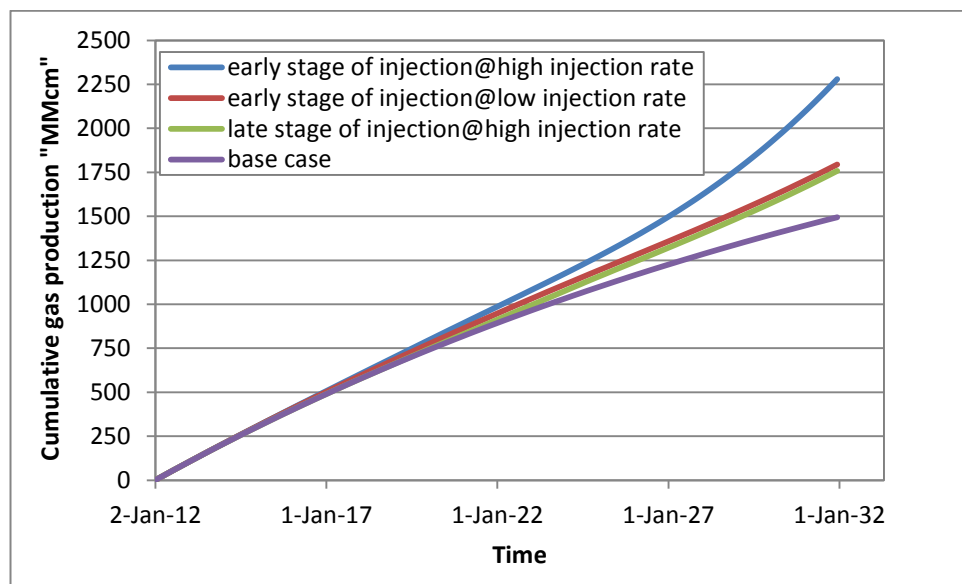


Figure 5.22: Cumulative CO₂ production under different cases

The simulation results show that higher CO₂ injection increases the amount of CO₂ sequestered (see Figure 4.16 and 4.17). This is because when the brine is fully-saturated; the partial displacement of the brine by CO₂ is expected to reduce connate water saturation. That is, more pore water is available to replace CO₂ sequestration. However at an early stage, low injection rate appears to provide an economic optimum. Further, at late-stage injection with a high rate also appears to be near optimum compared to low CO₂ injection at 1152 m³/d (early-stage injection).

A comparison of early- and late-stage injection in terms of production of the injected CO₂ and CO₂ storage is provided by Figures 4.15, 4.16 and 4.17. The economic evaluation of the scenarios suggests that return on investment is significantly affected by high CO₂ capture and storage costs. Clearly, higher price implies a better return on the investment. With low prices suggests only short-term projects are viable, as the revenue yield probably would not offset longer-term CO₂ production costs.

While research and development will provide lower production costs, carbon credits the application of net carbon credit schemes is probably more important in offsetting CCS costs. Clearly, the CCR approach could also reduce greenhouse gas emissions, thus futures carbon taxes might be of greater impact on carbon prices than CO₂ sequestration credits. Whatever the circumstances, the approach will probably be profitable due to the larger CO₂ sequestration volumes when compared to that for atmospheric release. The CO₂ injection stance is important in determining the economic feasibility of CO₂-EGR and storage. Other factors include: well location, depth completion, injection rate, vertical or horizontal well, and the commencement date of CO₂ injection. For an economic stance, well spacing is probably the most important factor determining the economic viability of reservoirs for CO₂ injection. By choosing smaller (closer) well spacing, CO₂ is produced earlier in the project, with sweep efficiency higher when compared to large (further apart) well spacing. However, another aspect economic viability is that a particular project may require large number of wells to be drilled and utilised for injection.

An economic analysis, based on the results of systematic compositional simulations of CO₂-EGR, is performed to establish the economic incentive required for viable EGR and storage. Several critical economic parameters, such as the gas price, project cost and discount rate, are identified. While these parameters impact on project economic viability, they are also affected by other economic incentives used to encourage the storage of more CO₂ in reservoirs. In most of the scenarios, the net carbon credit is sensitive to storage volumes and carbon emission. In particular, carbon credits increase with CO₂ storage. Even though carbon credits partially offset CO₂ storage costs, without intensive carbon taxes (with values higher than CO₂ sequestration costs), the base case remains more economically viable.

Chapter Six

Conclusion and Recommendation

CO₂ injection into natural gas reservoirs for enhanced gas recovery and storage is an important new technology throughout the world. The technique is promising for technical, commercial and environmental reasons. This chapter presents and discusses the conclusions of this study, and also provides recommendations for further study.

6.1 Conclusions

(A reservoir simulation model is developed by combining experimental data at high pressures and temperatures, with detailed engineering-economic modules. Both the reservoir simulations and laboratory studies indicated that the properties of methane and CO₂ (e.g. density, viscosity and solubility) are favourable for re-pressurization and pressure maintenance. Three-dimensional models of the grid cells are defined with initial pressure and temperature, phase contact and depth dependence of reservoir fluid properties by using compositional reservoir software “Tempest”. Overall, three main simulation cases were considered the hypothetical gas reservoir model. The models are developed as base-case, early-stage of injection with different injection rates, and late-stage of injection with the high injection rate. Simulations of the CO₂ injection process into natural gas reservoirs are conducted. The simulations confirm the potential for CO₂ injection as a means of storing carbon dioxide while also enhancing methane recovery.

In addition, the simulation results suggested that CO₂ injection and enhanced methane recovery is considered technically feasible for specific reservoirs, while gas-gas mixing can be ameliorated by good reservoir management and production control. Engineering-techno-economic models for CO₂-EGR and storage process (based on performance of the reservoir model) give robust qualitative comparisons. Separate economic modules are used to estimate the costs of capture, compression,

transport and injection. Additionally, other gas reservoir cost components are analysed to observe how changes in key assumptions, including cost of CO₂ separation, carbon price and tax, project discount rate, royalty income tax and CO₂ emission rate affect outcomes.

An economic analysis was also conducted to find the additional investment required or the incremental costs of producing natural gas and CO₂ storage in terms of “what if” as well as “what if is not”. In particular,

- Perforating production wells in layers with lower permeability reduce CO₂ production of the injected CO₂, but have unfavourable effects on the economics of the project in terms of enhanced methane production;
- Perforation of injection wells in the (bottom) layers with lower permeability have a favourable effect on CO₂ storage and reduce the production rate of the injected CO₂ that can benefit from carbon credits;
- CO₂ injection under high and low injection pressures was investigated. Results from the simulation indicated that injection into the reservoir at pressures greater than that is initially presented in the reservoir increases enhanced gas recovery and reduces potential CO₂ storage compared to that under lower injection pressures;
- The simulation studies report sufficient breakthrough of injected CO₂ on an individual well basis. In this case, CO₂ density, viscosity and solubility in the formation brine are considerably higher than that of methane, and cause a delay in CO₂ breakthrough, which promotes optimal natural gas recovery and CO₂ storage;
- Hydrocarbon volume extraction from reservoirs potentially provides enough room to store the produced CO₂ and additional CO₂ from power plant back into the reservoir. As long as the original natural gas reservoir pressure is not exceeded, storage of the injected CO₂ in gas fields is a secure option for storage of as much carbon as contained in the original natural gas;
- The CO₂ separation from natural gas production costs is considerably lower than the cost of additional CO₂ from power plants. The cost of CO₂ capture declines

after the occurrence of CO₂ breakthrough and conversely, CO₂ separation costs increase;

- According to the simulations, scenario comparisons suggest that higher rates of CO₂ injection provide a significant improvement in cumulative natural gas recovery and reservoir re-pressurisation simultaneously with large amounts of CO₂ storage. However, excessive gas mixing can be a drawback;
- Late-stage CO₂ injection is a second-best production and CO₂ storage method as the CO₂ injection time is reduced. Clearly, less time to inject CO₂ means reduced CO₂ storage costs. Also, CO₂ emissions due to launching CO₂ production and CO₂ released into the atmosphere prior to injection can jeopardize economic viability when a carbon tax is in place;
- Early-stage CO₂ injection at low rates is optimum case. Due to low CO₂ injection, CO₂ mixing and degradation in the produced gas is less than for the other CO₂ injection scenarios. Therefore, CO₂ capture, storage and emission of CO₂ costs during the project are lower than under the alternative scenarios. Therefore, the stage and mass flow rate of CO₂ injection are important for economic viability;
- Economically, the main obstacles to applying CO₂ storage are the high component process costs. Undoubtedly, new technology will reduce CO₂-EGR and storage costs. However, there is also a lack of supporting taxes and credit systems to encourage investment in CO₂ injection and storage. That is, prohibitive costs can be reduced by combining CO₂ sequestration with enhanced gas recovery with revenues from incremental natural gas recovery and credits from CO₂ storage (as an additional source of revenue); and
- Even though CO₂-EGR is demonstrated technically and economically feasible, should future carbon markets involve effective payment for CO₂ storage compared to carbon tax for CO₂ emissions the process will become more attractive. For the purpose of this study, the amount of injected CO₂ stored in candidate reservoirs is not the net carbon amount due to the emitted CO₂ into the atmosphere during the process

6.2 Recommendations

The results indicate that CO₂ injection for enhanced gas recovery and storage is a promising technology. Net carbon credits are robust factors in supporting the economic viability of the process. However, further investigation is required in terms of the reservoir development to obtain a better link between reservoir behaviour and economic viability. In particular:

- Better cost information and process improvements will require that the information contained in the thesis be updated;
- Further economic evaluations should consider comparisons of natural gas reservoirs when only CO₂ production re-injected, i.e., without additional CO₂ from other sources;
- Further analysis is required on fractured natural gas reservoirs and CO₂ injection, when the gas reservoir is depleted; and
- Other substances, such as acid gas or chemicals that allow the recovery of natural gas should be considered. Furthermore, economic evaluations are also needed to estimate incremental costs more than that the cost of conventional recovery.

Of course, the ultimate of study findings is in the field with actual fluids and flow conditions. The real-world offers true values for natural gas production and CO₂ storage. The real-world also offers improved insights into field operations; in particular, it allows a better understanding of optimal production and storage based on well depth completion, horizontal or vertical well perforation and well spacing.

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