Final Report

Final Year Project

Enhanced Coal Bed Methane Recovery by Gas Injection

By

Ikhwanul Hafizi bin Musa

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

September 2012

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CERTIFICATION OF APPROVAL

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A project dissertation submitted to the

Petroleum Engineering Programme

Universiti Teknologi PETRONAS

in partial fulfilment of the requirement for the

BACHELOR OF ENGINEERING (Hons)

Approved by,

____

(Ali Fikret Mangi Alta'ee)

UNIVERSITI TEKNOLOGI PETRONAS

TRONOH, PERAK

September 2012

CERTIFICATION OF ORIGINALITY

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

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IKHWANUL HAFIZI BIN MUSA

ABSTRACT

This paper is written for UTP's Final Year Project. The main focus of the paper is on a study on the comparison between primary recovery and enhance coal bed methane recovery in the same reservoir. For enhance coal bed methane recovery, two methods are used which are carbon dioxide injection and nitrogen injection. Using data from Law, Meer and Gunter (2002), simulation using Eclipse 300 simulator is used to simulate the behavior of the reservoir at different production methods. The simulation shows that both enhance recovery method able to obtain high recovery at faster rate compared to only primary recovery. Simulation using DOT.CBM simulator as comparison with Eclipse simulator showed a high agreement between the two simulators. Even though both enhance recovery method able to obtain high recovery, carbon dioxide injection is much more preferable compared to nitrogen injection due to its unique behavior which replace the methane content coal with carbon dioxide until breakthrough.

ACKNOWLEDGEMENT

Foremost, I would like to express my gratitude to my supervisor, Mr. Ali Fikret Mangi Alta'ee for his constant guidance throughout the 2 semester of the study and all of his patience and motivation. His guidance has helped me in all of the time of research and writing the final report. I could not imagine a better advisor and mentor for this research and study.

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Last but not least, my close friends, fellow classmate, family and my parent for their continuing support physically and spiritually throughout the research and my life.

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CHAPTER 1

INTRODUCTION

1.1 BACKGROUND STUDY

Coal bed methane (CBM) is a form of natural gas extracted from coal beds. It is considered as an unconventional reservoir however, recently has grown from something most operator stay away from into a commercial important, mainstream natural gas source (Aminian, 2003). One of the factors that contributed to the mainstreaming of coal bed methane as one of the world major sources of natural gas is the advancement of technology that includes an understanding of the coal bed methane production, development of well log interpretation and development of reservoir simulation. One of the advantages of coal bed methane that make it more attractive than conventional reservoir is that it generally has a very high concentration levels of methane recoverable making the gas produced can be use as direct replacement for conventional natural gas in pipeline network (source adapted from http://www.worldcoal.org).

1.2 PROBLEM STATEMENT

Most of the world's coal bed methane reservoir is produced by primary recovery through the dewatering of the reservoir and thus producing the methane when the reservoir pressure is reduced. However, due to various limitations and problems arising from primary recovery such as low recovery, low production rate and also environmental issues, enhance coal bed methane recovery methods are introduced. One of the most common methods for coal bed methane recovery is by injecting gas into the reservoir (Lin, 2010). Two of the most common gas used during gas injection is carbon dioxide, CO_2 and nitrogen, N_2 gas. By conducting simulation, the production of the coal bed methane reservoir during primary recovery and also enhanced coal bed methane recovery can be directly compared and observed. The simulation conducted will greatly help in the decision making of the reservoir management in deciding the best recovery method for optimum recovery and production.

1.3 OBJECTIVES AND SCOPE OF STUDY

The objectives of the study are:

1. Simulated and comparing the reservoir production behavior in primary recovery and enhance coal bed methane recovery
2. Compare the simulation result of coal bed methane production using ECLIPSE simulator and DOT.CBM simulator
3. Discuss and analyzed the best recovery mechanism of coal bed methane reservoir.

In this research study, most of the work is involving simulation regarding the recovery of coal bed methane using either ECLIPSE simulator or DOT.CBM simulator. Using data provided by Law, Meer and Gunter (2002), the difference recovery methods in their performance can be observed and this will help in deciding the best recovery method for the reservoir.

1.4 RELEVANCY AND FEASIBILITY OF THE STUDY

As petroleum engineer that is majoring in Reservoir Studies, the study of factors that affecting and increasing the production and recovery of CBM will become a source of future reference and will truly benefit future careers. Besides, as the world production of CBM is expected to increase from 3654 billion cubic feet in 2011 to 5150 billion cubic feet in 2021 (source adapted from http://www.marketsandmarkets.com), any study and investigation in the field of coal bed methane production and recovery will become a vital in the future development of the industry. The time frame of 2 semesters for Final Year Project (FYP) should be sufficient for simulation and studies of enhanced coal bed recovery.

CHAPTER 2

LITERATURE REVIEW

2.1 DEFINITION OF COAL BED METHANE

According to Ahmed and McKinney (2005), the term coal in coal bed methane (CBM) refers to sedimentary rocks that contain more than 50% by weight and more than 70% by volume of organic materials consisting mainly of carbon, hydrogen and oxygen in addition to inherent moisture. Both authors added that even though the terms "methane" is used frequently in the CBM industry, the produced gas is typically a mixture of C_1, C_2 and a small traces of C_3 mixed with heavier N_2 and CO_2. Thomas (2002) reported that the amount of gas retained by coal is a function of pressure, temperature, pyrite content and the structure of the coal.

2.2 COMPONENT OF COAL

According to Haenel (1992), coal is vegetal in origin. Ancient swampy plants were buried and formed peat which was believed to be the precursor of coal. The author added that the higher the degree of coalification, the higher the rank of the coal which determined by its composition. The inherent constituents of coal can be divided into "macerals" which is the organic equivalent of mineral made primarily of fossilized plant remains and "mineral matters" which is the inorganic fraction made of a variety of primary and secondary minerals (Thomas, 2002). There is also moisture content which made up of the whole coal.

The organic content of coal or macerals are divided into three major groups; vitrinite, exinite and inertinite (Thomas, 2002). Vitrinite or also known as huminite which originated form woody plant materials made up of 80% of coal. Exinite which also alternatively called liptinite is derived from lipids and waxy plant substances. The final organic component of coal, inertinite, is originated from oxidized plant material, for example char.

Inorganic content of coal is the incombustible mineral. The some of the mineral components of coal included clay, carbonate, iron disulphide, oxide and others. Thomas (2002) added that the minerals are either detrital or authigenic in origin, and were introduced into coal while peat was deposited or during the latter coalification process.

Moisture is another of one of the important properties of coal. Water affects gas adsorption on coal. Besides moisture from the groundwater and other extraneous moisture, there is also moisture within the coal itself or inherent moisture. According to Ward (1984), coal's inherent moisture may occur in four possible forms:

4.1 Surface moisture held on the surface of coal particles or macerals.
4.2 Hydroscopic moisture held by capillary force within the micro fractures of coal.
4.3 Decomposition moisture incorporated in the decomposed organic compounds of the coal
4.4 Mineral moisture comprised part of the crystal structure of hydrous silicates.

An effective way to remove moisture from coal is by heating a sample moderately under vacuum.

2.3 COMPARISON BETWEEN COAL BED METHANE AND CONVENTIONAL RESERVOIR

Aminian (2003) has stated few differences between coal bed methane and conventional gas reservoir. Unlike conventional gas which generated from source rock and subsequently migrated to a reservoir, coal bed methane act as both reservoir and source rock for methane. Coal is also a heterogeneous and anisotropic porous media and characterized by dual porosity system (the micropores and micropores). The dual porosity system of coal bed methane will be discussed in later section. Another difference between conventional reservoir and coal bed methane reservoir is in their production behavior. For a conventional reservoir, normally the gas production rate starts high and then gradually decline as the pressure within the reservoir decrease. Besides, there are little to almost no water production during convention natural gas production. However, during coal bed methane production, the gas production rate increase until it reached the peak then decreases. There is also high water production in the beginning of the reservoir production. Table 2.3 shows the summary for comparison between coal bed methane and conventional gas reservoir.

TABLE 2.3: Comparison between Conventional Reservoir and Coal Bed Methane (CBM) Reservoir (Aminian, 2003)

Characteristic	Conventional	CBM
Gas Generation	Gas is generated in the source rock and then migrates into the reservoir.	Gas is generated and trapped within the coal.
Structure	Randomly-spaced Fractures	Uniformly-spaced Cleats
Gas Storage Mechanism	Compression	Adsorption
Transport Mechanism	Pressure Gradient (Darcy's Law)	Concentration Gradient (Fick's Law) and Pressure Gradient (Darcy's Law)
Production Performance	Gas rate starts high then decline. Little or no water initially. GWR decrease with time.	Gas rate increases with time then declines. Initially the production is mainly water. GWR increases with time.
Mechanical Properties	Young Modules ~ 10^6 Pore Compressibility ~10^{-6}	Young Modules ~ 10^5 Pore Compressibility ~10^{-4}

2.4 COAL BED METHANE SYSTEM

Lin (2010) stated that coal bed methane is generated in two ways; biological process from the microbial action or thermal process due to an increase of temperature with depth of the coal. Levine (1991) suggested that the materials comprising a coal bed falls into two categories which are:

1. "Volatile" low-molecular weight materials (components) that can be liberated from the coal by pressure reduction, mild heating or solvent extraction.
2. Materials that will remain in the solid state after the separation of volatile components.

Remner et al. (1986) presented a comprehensive study on the effects of coal seam properties on the coal bed methane drainage process. The authors pointed out that reservoir characteristics of coal beds are complex because they are naturally fractured reservoirs that are characterized by two distinct porosity system which are:

1. Primary Porosity System which composed of very fine pores (micropores) with extremely low permeability. With such low permeability, the primary porosity is both impermeable to gas and inaccessible to water. However, the desorbed gas can flow through the primary porosity system by the diffusion process.
2. Secondary Porosity System or macropores of coal seams consists of the natural fracture networks of cracks and fissures inherent in all coal. The macropores also known as cleats act as a sink to the primary porosity system and provide the permeability for fluid flow. The cleats are mainly composed of the "face cleat" which is continuous throughout the reservoir and capable of draining large areas and "butt cleat" which contact smaller area of the reservoir and thus are limited in their drainage capacities.

In addition to the cleat system, a facture system caused by tectonic activity may also be present in coals. Water and gas flow to coal bed methane wells occurs in the cleat and fracture system which combined to make up the bulk permeability measured from well tests conducted on coal bed methane wells.

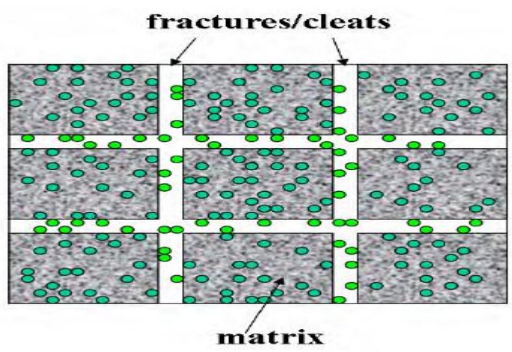


FIGURE 2.4: A Simplified Model of Coal Bed Methane Structure and Gas (Lin, 2010)

2.5 COAL BED METHANE PRODUCTION

As stated previously, coal bed methane is a dual porosity system where the gas is stored by the adsorption of the in the coal matrix. This in turn causes the pressure volume relationship is described by sorption isotherm which relates the gas storage capacity of a coal to pressure. The typical sorption isotherm is shown in Figure 2.2. The common relationship between gas storage capacity and pressure can be described by an equation presented by Langmuir:

$$G_s = \frac{V_L P}{P_L + P} \qquad (1)$$

Where: G_s= Gas storage capacity, scf/ton

P = Pressure, psia

V_L= Langmuir volume constant, scf/ton

P_L= Langmuir pressure constant, psia

Equation (1) assumes pure coal in the field. In order to account for ash and moisture contents of the coal, the equation is modified:

$$G_s = (1 - f_a - f_m)\frac{V_L P}{P_L + P} \qquad (2)$$

Where: f_a= Ash content, fraction

f_m=Moisture content, fraction

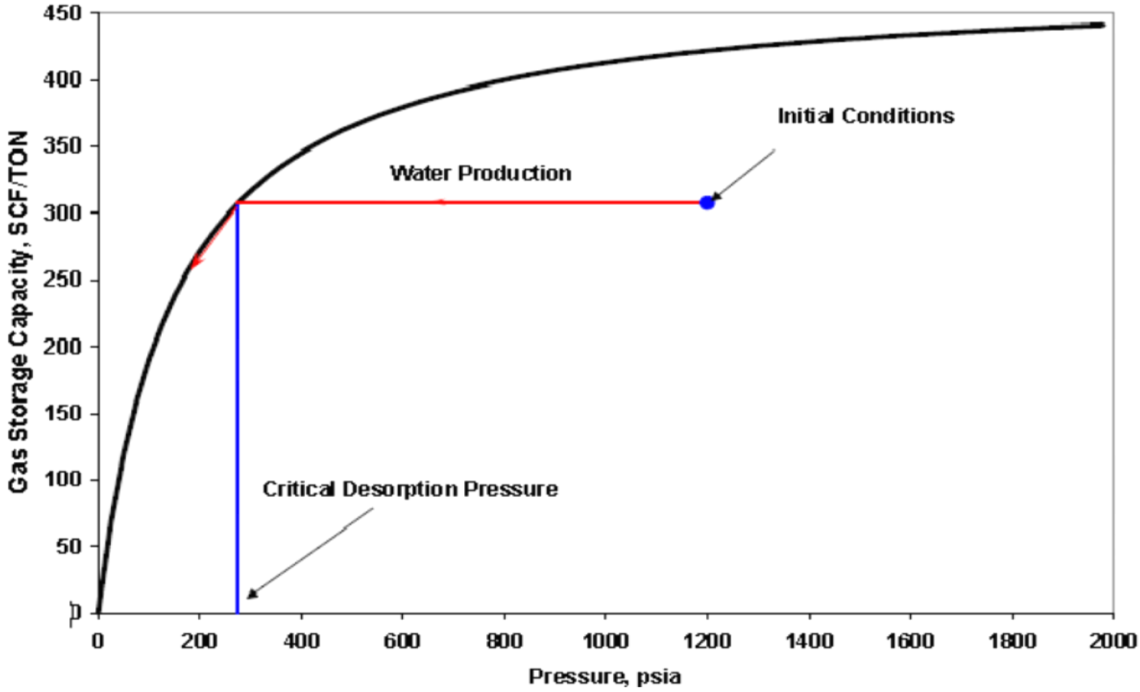


FIGURE 2.5a: An Example of Langmuir Isotherm
(Aminian, 2003)

According to Aminian (2003), most of the coal bed methane reservoir initially only produced water as the cleats is filled with water. Water must be produced continuously in order to reduce reservoir pressure and release the gas. The author added that once the pressure in the cleat system is lowered by water production to the critical desorption pressure gas will be desorbed from the coal matrix. The critical desorption matrix is defined by the author as the pressure on the sorption isotherm that corresponds to the initial gas content. As the desorption process continues, a free methane gas saturation builds up within the cleat system and once the gas saturation has been exceeded, the desorbed gas will flow along with water through the cleat system to the production well.

As the desorption process continues, both the gas saturation and the flow of methane increases and becomes more dominant. Thus, the water production will decline rapidly until it reached a point where the gas rate reached peak value and water saturation approaches the irreducible water saturation. Figure 2.5b shows a typical coal bed methane reservoir production.

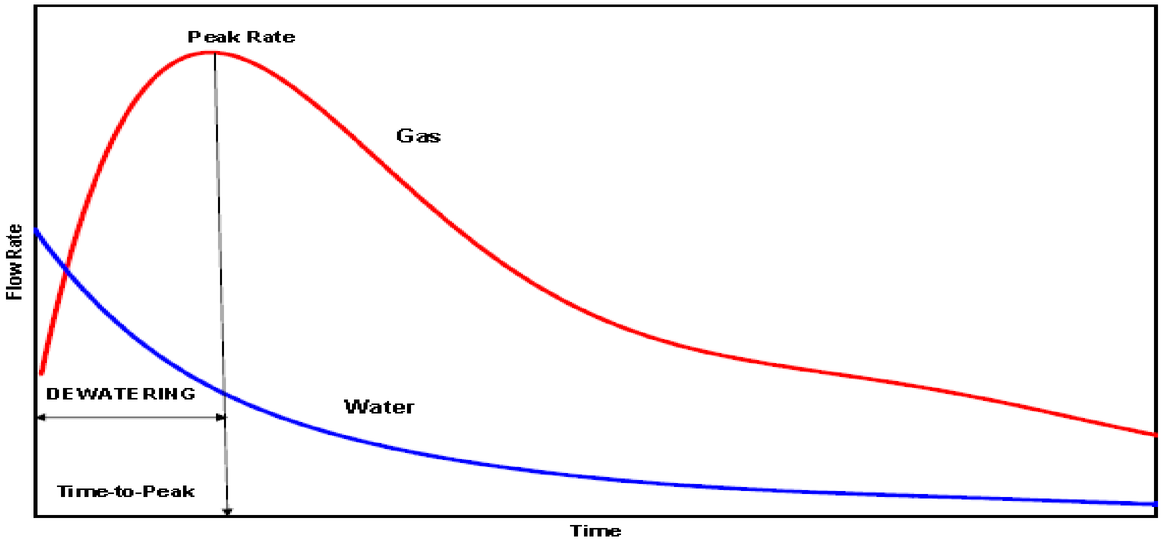


FIGURE 2.5b: A Typical Production History of a Coal Bed Methane Reservoir (Aminian, 2003)

According to Lin (2010), to recover the methane gas from the reservoir, certain conditions must be fulfilled to initiate the desorption of the gas:

1. Decrease of the reservoir pressure
2. Presence of a more absorbable gas (example carbon dioxide, CO_2)
3. Reduction in the methane partial pressure

Lin (2010) reported most of the coal bed methane production in the world is using primary recovery method in an open holed production wells. During the production, downhole submersible pumps are used to move formation water up the tubing which decreases the reservoir pressure. Methane in turn, will be desorbed from the coal surface, diffuse to the cleats or fracture network and flows to the wellbore.

However, the author added that there are certain limitations of primary recovery. An example provided by Stevens et al (1998) is primary recovery by depressurization typically recovers less than half of the resource underground. Rawn-Schatzinger (2003) also added environmental problems and operational issues during primary recovery.

2.6 ENHANCE COAL BED METHANE (ECBM)

In order to increase the production rate as well as solving some of the problems associated with primary recovery, the potential of enhanced coal bed methane (ECBM) recovery method using substitution gas injection is under investigation. Two type of popular variants used are inert gas stripping using Nitrogen, N_2 and displacement resorption method using Carbon Dioxide, CO_2. Tang et al. (2005) reported that laboratory experiments showed that greater recovery ratio and less water production are achieved during gas injection ECBM process.

The potential of Nitrogen gas to use in gas injection was investigated thoroughly by Zhu et al. (2002) and also by Stevens et al. (1998). N_2 is chosen because it is abundant and as inert gas, it is only slightly absorbable on coal. In this process, methane will be desorbed as the partial pressure inside the pore decreases and later carried away by the continuous N_2 flow. The produced gas mixture is separated in the surface facilities. Zhu et al. (2002) reported the injection of N_2 will typically give an earlier incremental coal bed methane recovery. Simulation and N_2 injection project conducted by Stevens et al. (1998) reported nitrogen injection is capable of 90% recovery of gas in place and the average incremental capital and operating cost of about $1.00/MCF. As discussed, injection of nitrogen reduces the partial pressure and therefore producing methane from the coals in the fracture system. Even though the partial pressure is reduced, the total pressure is generally constant and the fluids maintain head that drives liquid to the production wells. Coals can replace between 25% to 50% of their methane storage capacity with nitrogen (adapted from www.epa.gov).

Compared to Nitrogen, Carbon Dioxide, CO_2 is more preferable as an injection gas due to its effectiveness in displacing methane on the coal surface and also the benefit of sequestering a greenhouse gas in the subsurface (Lin, 2010). In this process, CO_2 displaces the methane on the coal surface as coal has a stronger affinity for CO_2 which in turn resulted to methane been produced and the CO_2 retained. According to www.epa.gov, when carbon dioxide, injected into a CBM reservoir, an increased of methane production will occur as the adsorption of CO_2 cause the desorption of methane. This process has the potential to sequester large volumes of CO_2 while improving the efficiency and potential profitability of natural gas recovery. Lab studies indicate that coal adsorbs nearly twice as much volume of CO_2 as methane. In order to consider the multiple components during enhance coal bed methane production; the Langmuir isotherm theory as shown in Eq. (2) has to be modified as shown:

$$G_{si} = G_{sLi}[1 - (f_a + f_m)] \frac{\frac{Py_i}{P_{Li}}}{1+P\sum_{j=1}^{nc}\frac{y_j}{P_{Lj}}} \quad (3)$$

Where: G_{si}=multicomponent storage capacity of component i, in-situ basis

G_{sLi}=single component Langmuir storage capacity of component i, dry, ash-free basis

$P_{Li}$and P_{Lj}= single component Langmuir pressure of component i or j

$y_i$and y_j= mole fraction of component i or j in the free gas phase

nc = number of components

2.7. CASE STUDY INVOLVING ECBM

Lin (2010) stated that even though no large-scale field CO_2-ECBM implementation has occurred, pilot projects were conducted. In a study conducted by Stevens et al. (1998), at the world's first CO_2-ECBM pilot in the San Juan Basin, using continuous injection of carbon dioxide, CO_2, the optimal gas production was as high as 150% of the primary recovery methods with negligible breakthrough of CO_2. The project was found to be profitable and as much as 13Tscf of additional methane resource potential is added within the San Juan Basin.

Another pilot study on ECBM was conducted in the Horseshoe Canyon of Alberta, but this time using Nitrogen, N_2 injection. According to a study conducted by Settari and Bachman (2010) and also by Bastian, Wang and Voneiff (2005), the Horseshoe Canyon of Alberta consists of essentially dry coal (without water production) and it is produced in wide range of depth including very shallow (less than 200m) wells. Due to the unique nature of Horseshoe Canyon CBM (dry coal reservoir), the injection of water into the coal will result to a high damage to the reservoir which also eliminated the use of other traditional stimulation technique such as foaming. Thus, dry nitrogen injection is used and has since resulted to over 100 MMscfd of gas production and the future production is expected to increase exponentially (Bastian, Wang and Voneiff, 2005).

2.8 SIMULATION IN CBM

Coal bed methane production behavior is a complex and difficult to predict and analyzed especially in the early stages of recovery (Aminian, 2003). This is due to the gas production of CBM governed by a complex interaction of single-phase gas diffusion through the micropore system and two-phase gas and water flow through the macropore system that are coupled through the desorption process. This makes numerical reservoir simulator makes the best tool to predict CBM reservoir behavior as it incorporates the unique flow and accounts for various mechanisms that control CBM production. According to Law et al (2002) in order to model the primary recovery process of a coal bed methane, many important features has to be taken into account such as:

- Dual porosity nature of coal bed.
- Darcy flow of gas and water or multiphase flow in the natural fracture system in the coal.
- Diffusion of a single gas component from the coal matrix to the natural fracture system.
- Adsorption/desorption of a single gas component at the coal surface.
- Coal matrix shrinkage due to gas desorption.

Besides that, history matching with a simulator is one of the key tools in determining reservoir parameters and characteristics that are often to obtain by other techniques.

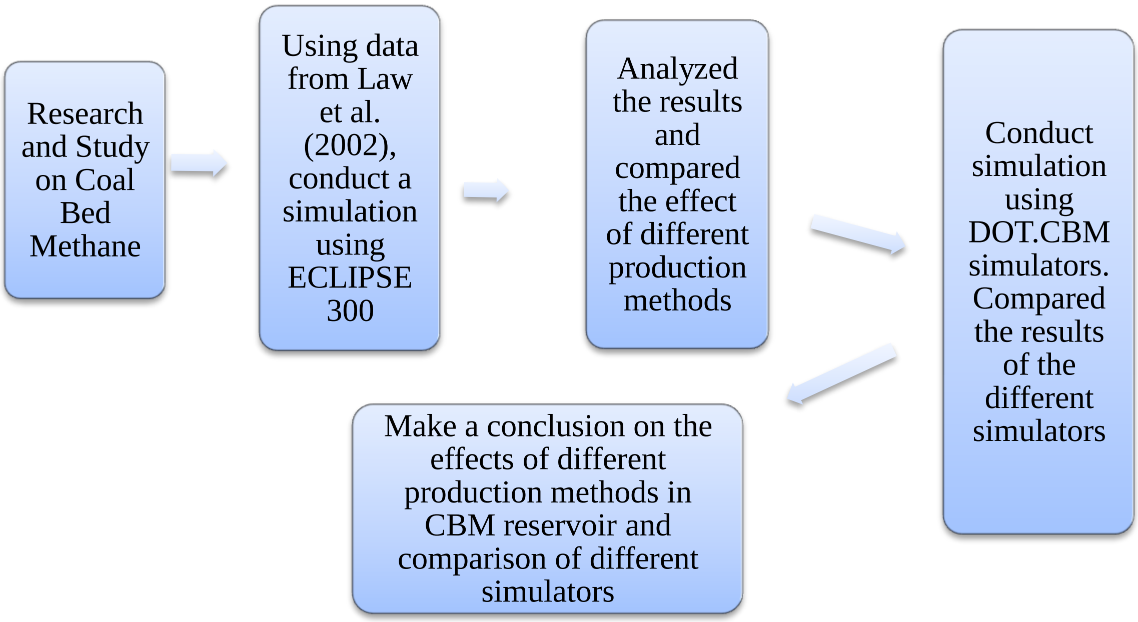
According to Seidle and Arri (1990), the coal degasification is a two-step process; desorption of gas from the coal matrix followed by flow through the fractures. The slower of the two processes will control the rate of gas production from a coal. If the rate of desorption of the gas from the matrix is very slow, diffusion equations need to be incorporated into a conventional simulator to describe gas production. However, if the release of the gas is very rapid, gas production can be modeled by Darcy's Law only. The authors added that the amount of gas held at a given pressure is analogous to the amount of gas dissolved in black oil at a given pressure. The Langmuir isotherm of coal beds is comparable to the solution gas-oil ratio of conventional oil reservoir. A conventional reservoir simulator can be used to describe coal bed methane by treating the gas adsorbed to the surface of the coal as gas dissolved in immobile oil.

However, according to Seidle and Arri (1990), some modifications in the input data has to be made before conventional simulator can be used. In their approach, the solution gas oil ratio is calculated using Langmuir isotherm. Some modification in the input data (such as the porosity and gas-water relative permeability curves) has to be applied in the presence of the immobile oil. However, no code modifications in the simulator are required.

CHAPTER 3

RESEARCH METHODOLOGY

Using data from a study by Law et al. (2002), simulations were conducted using Eclipse 300 simulator in three different scenarios which are; primary recovery, enhanced recovery using CO_2 and enhanced recovery using N_2. The study by the author is comparing the inverted 5-spot CO_2-ECBM recovery for 185 days using various commercial simulators. However, in this study, even though same data are used, only two wells are investigated (production and injection well) in three different scenarios which are primary production, CO_2 injection and also N_2 injection for a year production (365 days). Various parameters are investigated and observed when different recovery methods are used and the results are also compared using DOT.CBM simulator. Below is a summary of the study's methodology:



3.1 TOOLS

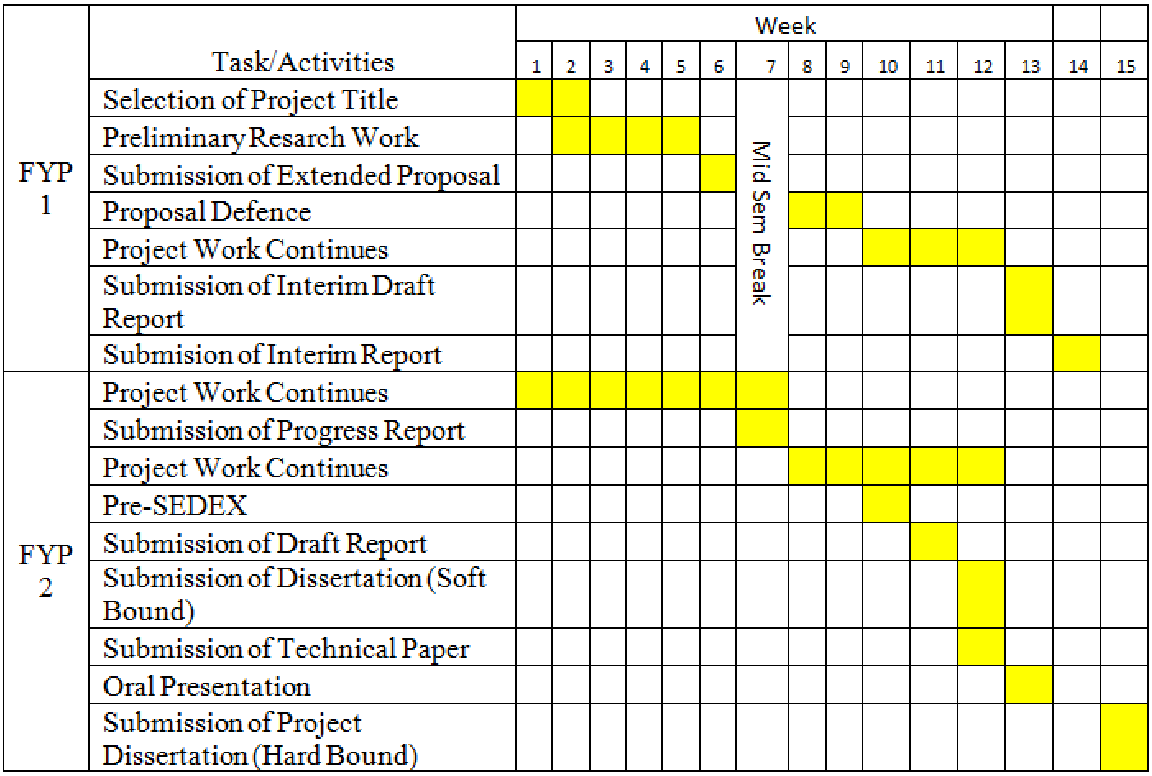
3.1.1 ECLIPSE Simulator

One of the most common reservoir simulators is ECLIPSE which has been developed by Schlumberger. ECLIPSE consist of two parts which are ECLIPSE 100 based on “black oil model” simulator and ECLIPSE 300 which is based on “compositional model”. The simulator can be used to simulate the production behavior of coal bed methane reservoir as shown by Seidle and Arrid (1990). This simulator has incorporated sorption and diffusion processes, coal shrinkage, compaction effects and under-saturated coals to its dual porosity models. The model can handle two gas systems (typically CO_2 and methane) in both primary production and injection modes. In addition, simple and complex well completions such as multi-branch horizontal wells and hydraulic fracture treatment can also be simulated. Besides that, Schlumberger also has developed a template specifically designed to assist the simulation of coal bed methane in the ECLIPSE’s “Office” section.

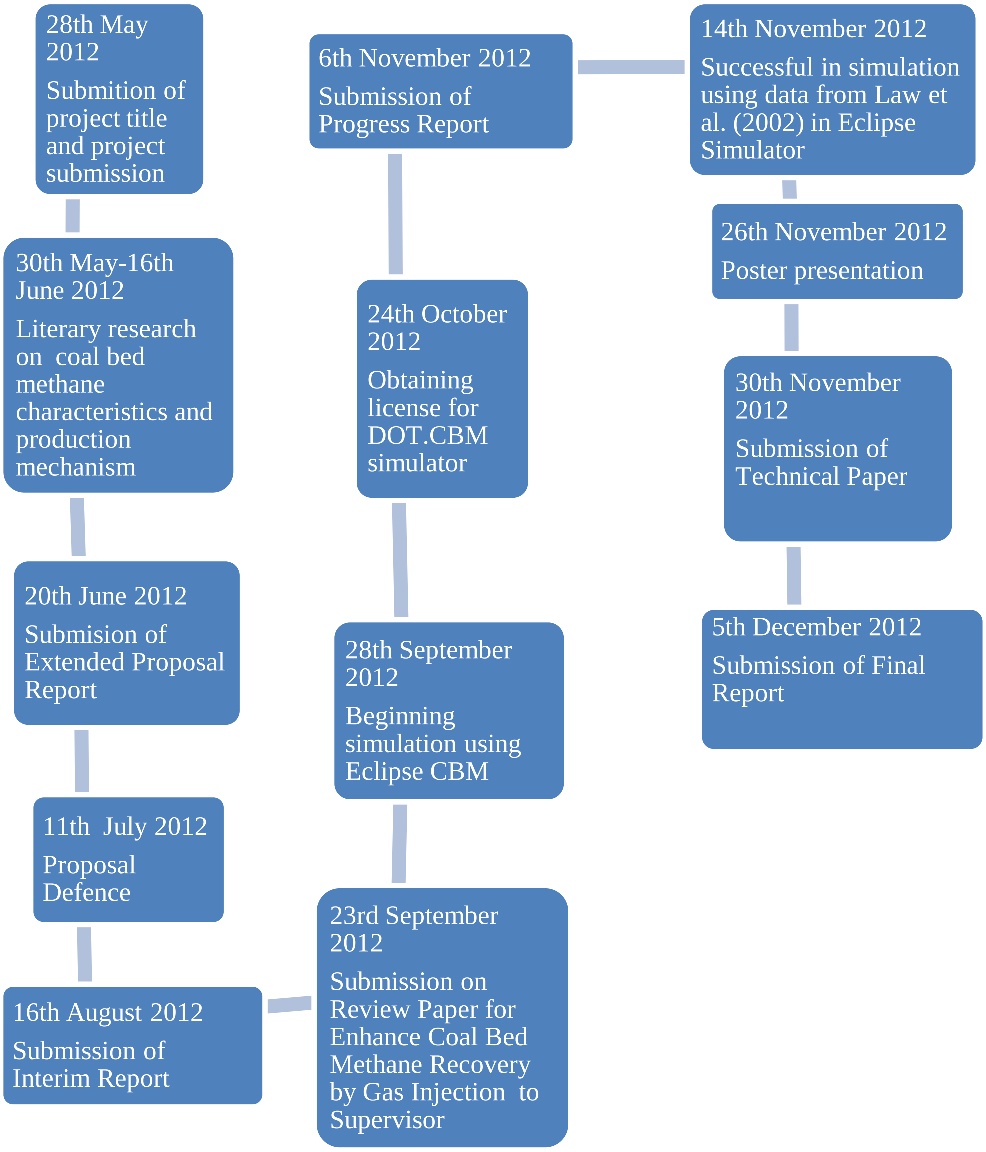
3.1.2 DOT.CBM Simulator

Unlike ECLIPSE Simulator,the DOT.CBM Simulator is a numerical simulator specifially designed to simulate the behavior of a coal bed methane reservoir production. The simulator is designed by Leap Energy and claimed to integrate the company’s development planning expertise with the latest generation software engineering technology. The simulator provides production forecasting, field development planning optimisation and production history matching to the user and shall be serve as comparison and compliment for some of features not avalible in ECLIPSE simulator in this study.

3.2 <u>GANNT CHART</u>



3.3 KEYMILESTONE



3.4 DATA FOR SIMULATION

3.4.1 Data from Law et al (2002)

In this study, a coal bed methane reservoir with the area of 2529.5 m^2 or 27215.1 ft^2 (0.625 acres) produced using primary recovery and compared with enhance recovery techniques by carbon dioxide, CO_2 injection or by nitrogen, N_2 injection. The reservoir contained $2.4x10^5$ m^3 or 8.48mm scf of methane, CH_4 gas initial gas in place with an underground aquifer. For enhance recovery techniques, the reservoir is injected continuously from the first day with gas injection rate of $2.5x10^5$ scf/day. Figure 3.4.1(a) shows the plane view the reservoir and the wells position.

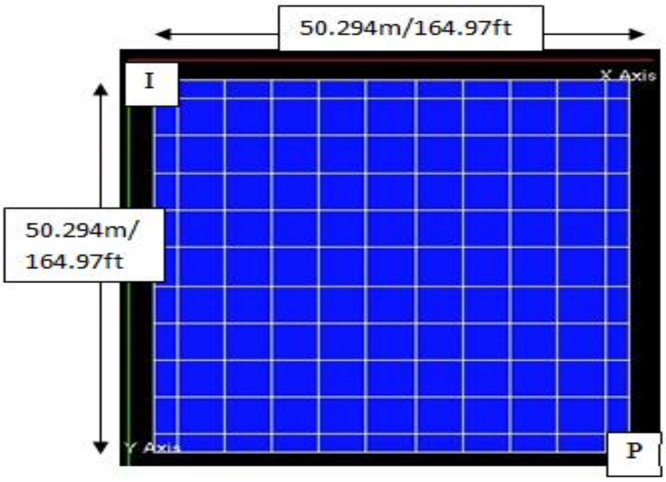


FIGURE 3.4.1(a): Plane View of the Model Showing the Producer and Injector Wells

- Grid system
  Rectangular grid (11x11x2)

TABLE 3.4.1a: Rectangular Grid System used

i or j	Δx orΔy		x or y	
	(m)	(ft)	(m)	(ft)
1	2.5	8.2	2.5	8.2
2	5.0	16.4	7.5	24.6
3	5.0	16.4	12.5	41.0
4	5.0	16.4	17.5	57.4

5	5.0	16.4	22.5	73.8
6	5.294	17.37	27.794	91.17
7	5.0	16.4	32.794	107.57
8	5.0	16.4	37.794	123.97
9	5.0	16.4	42.794	140.37
10	5.0	16.4	47.794	156.77
11	2.5	8.2	50.294	164.97

- Well Location
    I. Producer well (i=11, j=11, k=1)
    II. Injector well (i=1, j=1, k=1)
        - Injection Rate = 7079.2 m^3/day (0.25x10^6 cuft/day)
        - Well radius = 2 7/8'' (0.0365m/0.11975ft)
- Coal Bed Characteristics
    I. Reservoir Properties

Coal Seam Thickness	= 9m (29.527ft)
Top of Coal Seam	= 1253.6m (4112.8ft)
Absolute Permeability of Natural Fracture	= 3.65md
Porosity of Natural Fracture System	= 0.001
Effective Coal Bed Compressibility	= 1.45x10^{-7}/kPa (1x10^{-6} $psia^{-1}$)

    II. Initial Reservoir Conditions

Temperature	= 45^{o}C (113^{o}F)
Pressure	= 7650kPa (1109.5 psia)
Gas Saturation	= 0.408 at 100% CH_4
Water Saturation	= 0.592

    III. Water Properties at Reservoir Initial Conditions

Density	= 990kg/m^3 (61.8lb/ft^3)
Viscosity	= 0.607cp
Compressibility	= 5.8x10^{-7}/kPa (4x10^{-6} $psia^{-1}$)

- Langmuir Isotherm Parameters

TABLE 3.4.1b: Langmuir Isotherm Parameters for Methane, CH_4, Carbon Dioxide, CO_2 and Nitrogen, N_2 of the simulated coal bed methane

	Methane, CH_4		Carbon Dioxide, CO_2		Nitrogen, N_2	
Langmuir Pressure, P_L	46.885bar	680psia	19.030bar	276psia	27.241bar	3951psia
Langmuir Volume, G_L	0.01180736 m^3/kg	486 scf/ton	0.0240808 m^3/kg	993.8 scf/ton	0.0150 m^3/kg	482 scf/ton

- PVT data

TABLE 3.4.1c: Relative Permeability Relationship

Sw	Krw	Sg	Krg	Sw	Krw	Sg	Krg
0	0	0	0	0.55	0.116	0.5	0.216
0.05	0.0006	0.025	0.0035	0.6	0.154	0.55	0.253
0.1	0.0013	0.05	0.007	0.65	0.2	0.6	0.295
0.15	0.002	0.1	0.018	0.7	0.251	0.65	0.342
0.2	0.007	0.15	0.033	0.75	0.312	0.7	0.401
0.25	0.015	0.2	0.051	0.8	0.392	0.75	0.466
0.3	0.024	0.25	0.07	0.85	0.49	0.8	0.537
0.35	0.035	0.3	0.09	0.9	0.601	0.85	0.627
0.4	0.049	0.35	0.118	0.95	0.737	0.9	0.72
0.45	0.067	0.4	0.147	0.975	0.814	0.95	0.835
0.5	0.088	0.45	0.18	1	1	1	1
0.55	0.116	0.5	0.216				

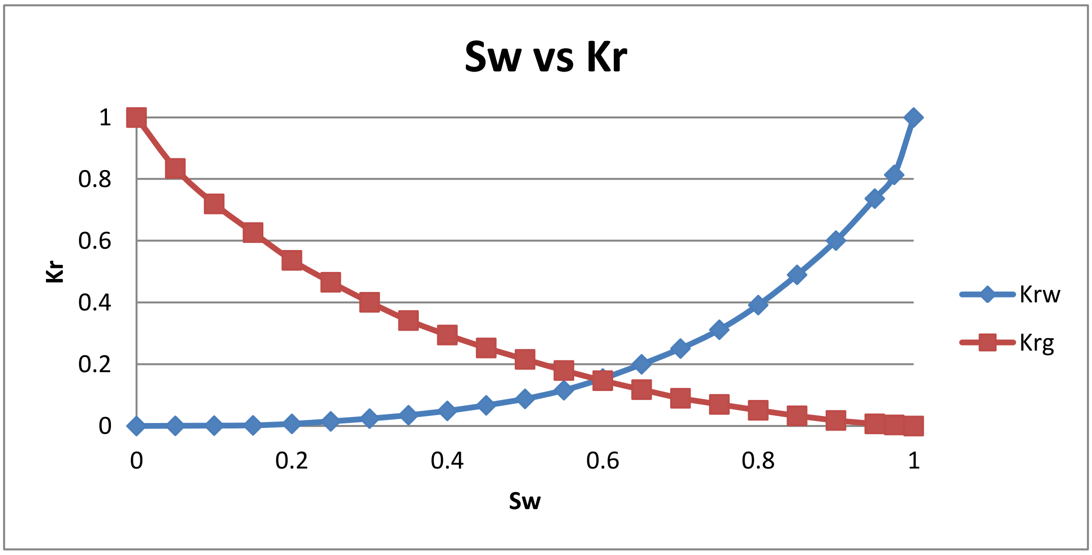


FIGURE 3.4.1b: Relative Permeability Graph

3.4.2 Data for Larger Reservoir

The reservoir used by Law et al. (2002) is only 0.625 acres and as a result, the production life of the reservoir is quite short. It is interested to see what is the coal bed methane reservoir production behavior is similar in larger reservoir. The grid of the reservoir is then changed to 23x23x2 and covered an area of 12164.8m^2 or 130940.5ft^2 (3.006 acres), however other parameter such as injection rate, coal thickness, porosity and other reservoir and fluid properties remained the same as shown in section 3.4.1. Fig. 3.4.2 showed the plane view of the new coal bed methane reservoir.

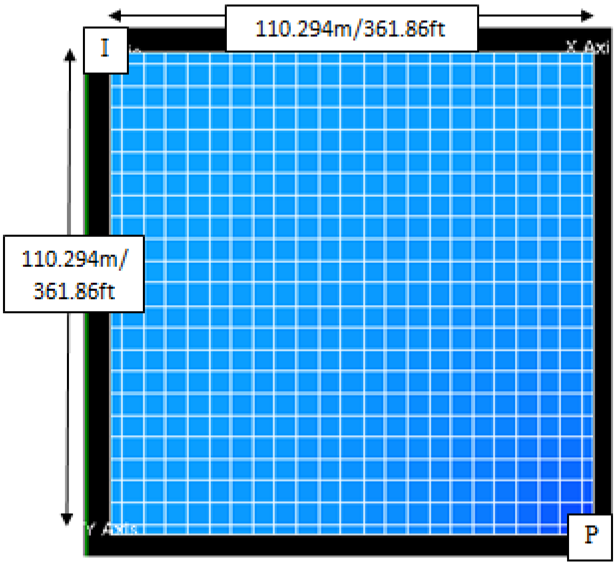


FIGURE 3.4.2: The Plane View of New Reservoir

The reservoir is simulated for 10 years in primary production and different enhanced recovery methods. The production behavior at different recovery methods is later observed and analyzed.

CHAPTER 4

RESULTS AND ANALYSIS

4.1 COMPARISON BETWEEN PRIMARY RECOVERY AND ENHANCED COAL BED METHANE RECOVERY

Figures 4.1a-c shows the result of the coal bed methane production rate at different recovery methods after one year (365 days) production. The red color represented methane production rate, green color represented injection gas either carbon dioxide, CO_2 or nitrogen, N_2 and finally blue color represented the total gas production rate.

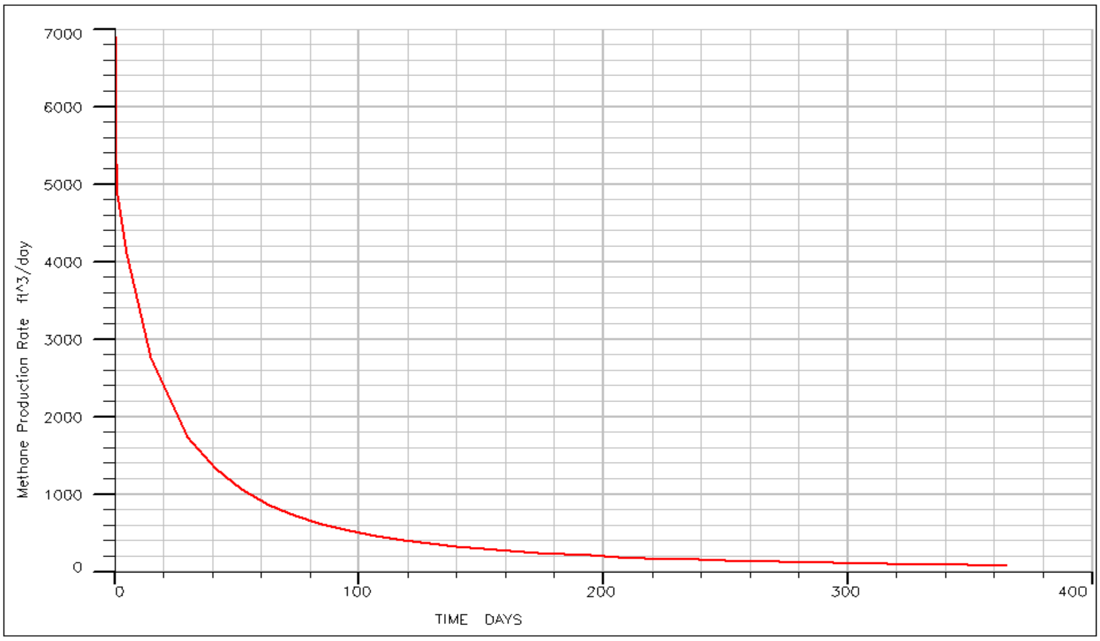


FIGURE 4.1a: The Production Rate during Primary Recovery in One Year

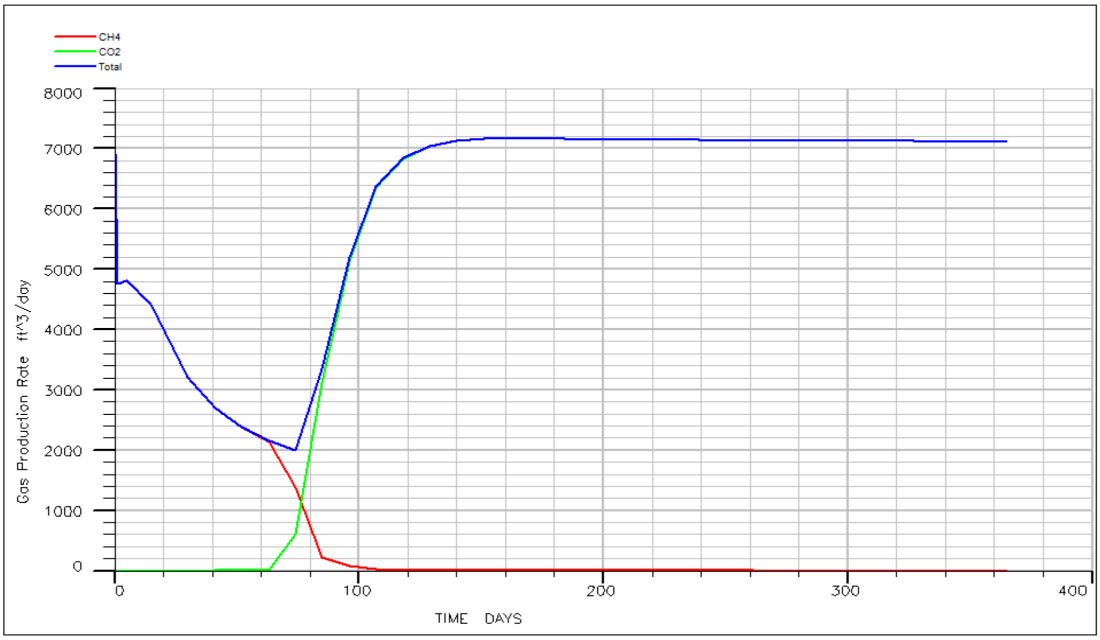


FIGURE 4.1b: The Production Rate during Carbon Dioxide, CO_2 Injection in One Year

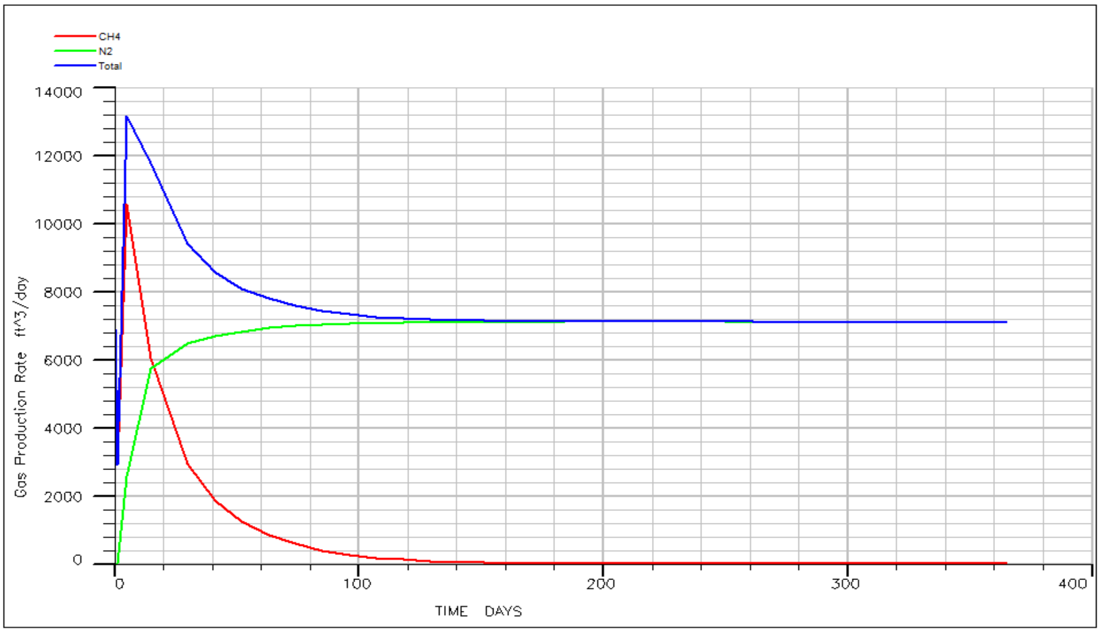


FIGURE 4.1c: The Production Rate during Nitrogen, N_2 Injection in One Year

The figures showed that the production rates and patterns for each recovery method are different. In primary recovery, the production rate decrease slowly from the beginning until the end of the simulation. The peak of the production rate is at the beginning of the production at 6912cuft/day. The behaviors of the primary recovery methods are further discuss in another the next section.

Compared to primary recovery however, for both enhance recovery methods, the methane production declined is much faster especially once breakthrough occurs and eventually the field wills only produced the injected gas (either CO_2 or N_2). In carbon dioxide injection, breakthrough begun after 57 days of production and the field will complete the methane production after only 112 days. As discussed in earlier section, coal has higher affinity to carbon dioxide compared to methane. This caused the coal surface to absorbed carbon dioxide completely and as a result produced methane to the subsurface. However, once the storage capacity of the carbon dioxide in the coal has been reached, the well will started to produced carbon dioxide along with methane (at 57 day) until all the methane has been completely produced (112 days). From that time onward, the well is only producing carbon dioxide and the well should be abandoned.

Comparison between Fig. 4.1a and 4.1c showed there are a lot of similarity between the pattern of primary recovery and nitrogen injection for the production of methane. In this recovery techniques, the production rate increase until it hits a peak (the peak for total production rate is 13200cuft/day while the peak production rate for only methane component is 10600cuft/day) then slowly decrease until the end of the simulation. This is because just like primary recovery, the production mechanism of nitrogen injection is due to the reduction of partial pressure in the reservoir and methane is produced as the result. Unlike carbon dioxide, nitrogen is an inert gas and is not adsorbed into the coal surface thus nitrogen is produced alongside methane since production begun. Just like carbon dioxide injection, methane has been completely produced before one year in approximately 180 days.

Figure 4.1d and 4.1e shows the individual gas component in the production well for both carbon dioxide and nitrogen injection respectively. The figures show a clearer behavior of the reservoir during enhance coal bed methane recovery and the time where the reservoir has completely produced methane at 112 days for carbon dioxide and slightly longer 180 days for nitrogen injection. The red color in the plot represented the methane component while the green color represented the injected gas (carbon dioxide or nitrogen).

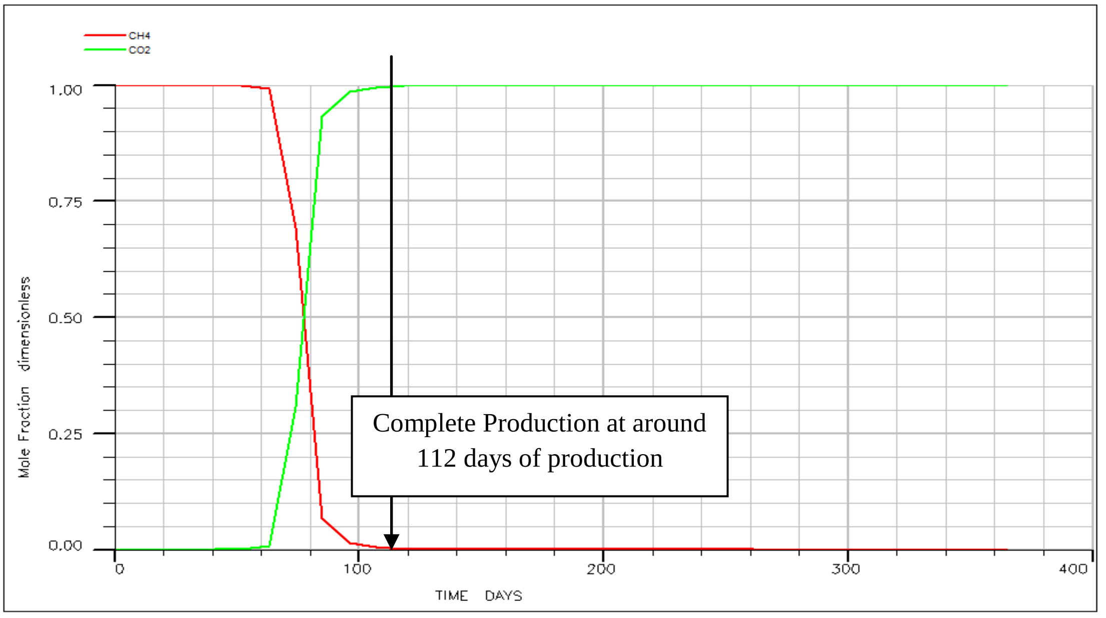


FIGURE 4.1d: The Mole Fraction in Production Well for Carbon Dioxide, CO_2 Injection

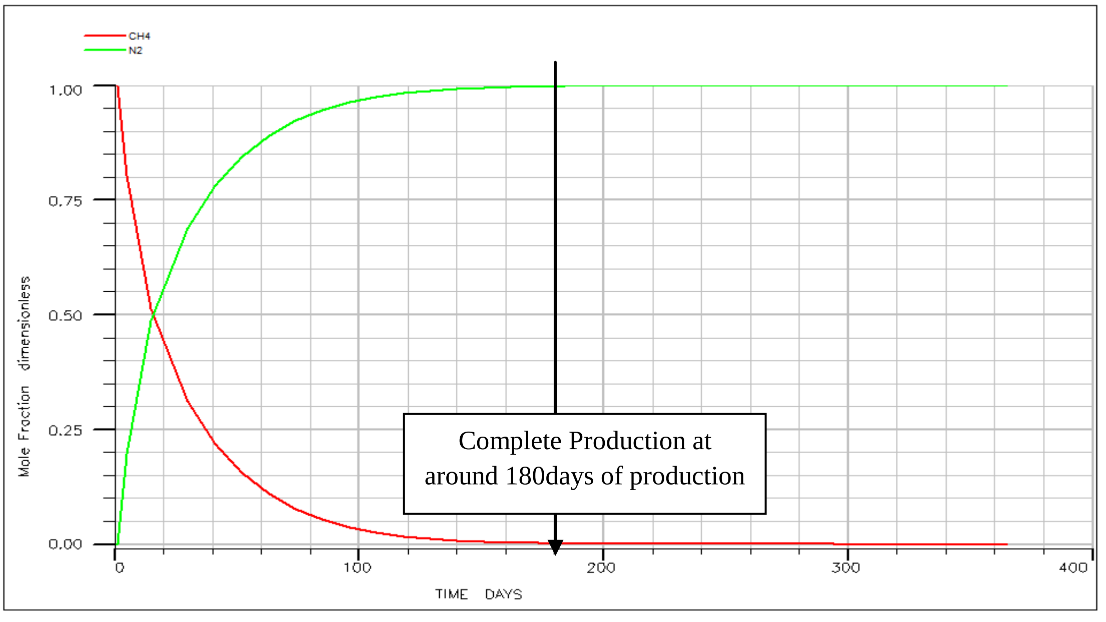


FIGURE 4.1e: The Mole Fraction in Production Well for Nitrogen, N_2 Injection

Figures 4.1f and 4.1g shows the reservoir total methane production and the water cumulative production. The red color shows the primary recovery, green color is carbon dioxide injection, and the blue color is nitrogen injection.

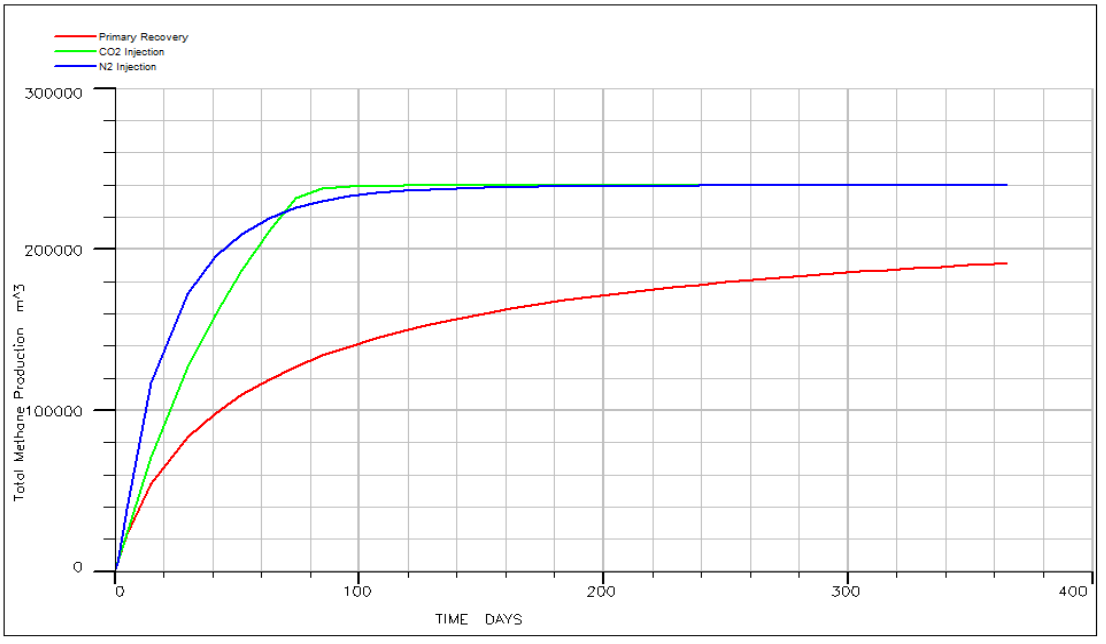


FIGURE 4.1f: Total Methane Production for Primary Recovery, Carbon Dioxide, CO_2 Injection and Nitrogen, N_2 Injection

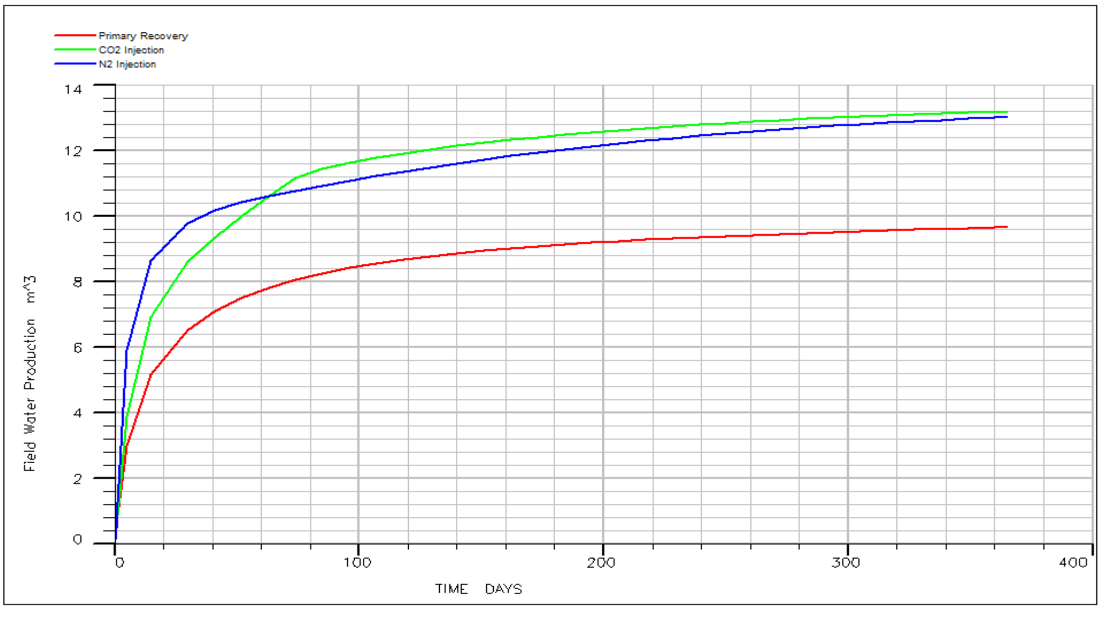


FIGURE 4.1g: Field Water Production for Primary Recovery, Carbon Dioxide, CO_2 Injection and Nitrogen, N_2 Injection

The figures shows that even though both enhance recovery methods will results to very short total recovery life (112 days for CO_2 injection and 180 days for N_2 injection), both of them able to obtain total recovery of methane of 240000m^3 (8.48MMcuft) while primary recovery method only recovered 188889m^3 (6.67MMcuft) of methane after one year.

This means that despite early breakthrough and short production life, both enhance recovery methods manage to recover 100% recovery while the primary production has a 78.7% recovery after 1 year.

4.2 PRIMARY PRODUCTION AT DIFFERENT YEARS

From the behavior of the primary recovery from previous section, it is interesting to investigate whether just by primary production, will the reservoir achieved 100% recovery in later years? In order to investigate this hypothesis, using the same data, the reservoir is continually produced for 10 years in order to investigate the limitation of the recovery for the reservoir. Fig. 4.2a and 4.2b shows the results of the simulation of the production of methane and water at different years using only primary recovery.

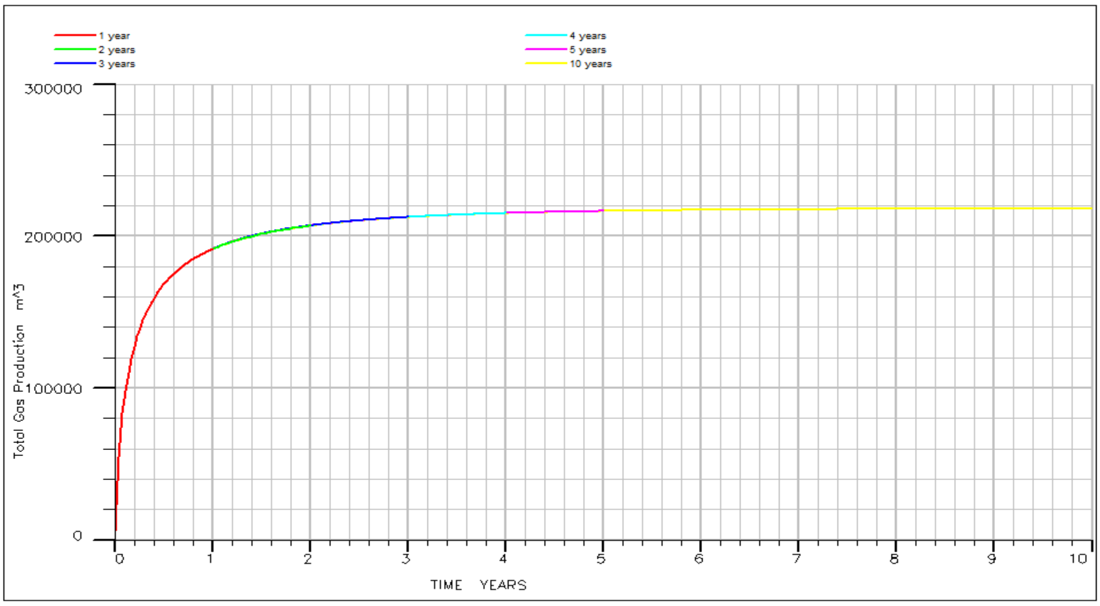


FIGURE 4.2a: Methane Total Production for Primary Recovery Method at Different Production Years

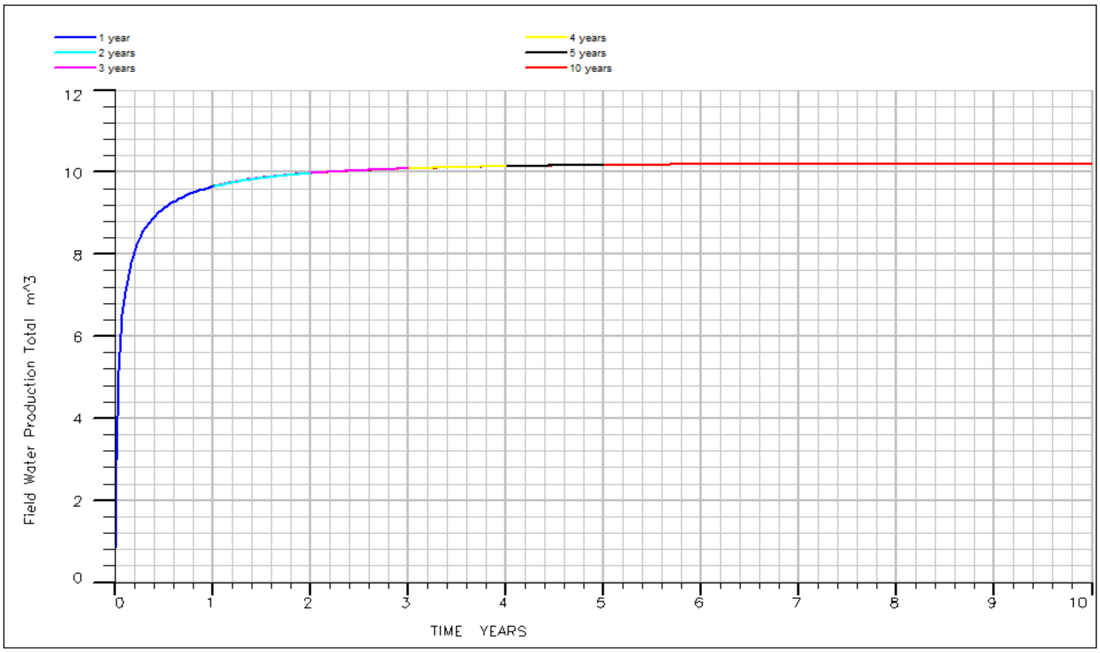


FIGURE 4.2b: Field Water Total Production for Primary Recovery Method at Different Production Years

Table 4.2a and 4.2b shows more detailed data for the production of methane and field water of the simulated coal bed methane reservoir.

TABLE4.2a: Methane Production for Primary Recovery at Different Years

Year	Methane				
	Production during the year (m3)	Production during the year (ft3)	Cumulative Production (m3)	Cumulative Production (MMcuft)	Production Rate at the end of the year (cuft/day)
1	186188	6.575E+06	186188	6.575	103.640
2	20066	7.086E+05	206254	7.284	24.394
3	6100	2.154E+05	212354	7.499	9.972
4	2617	9.242E+04	214971	7.592	5.012
5	1349	4.764E+04	216320	7.639	2.702
10	1623	5.732E+04	217943	7.697	0.173

TABLE 4.2b: Field Water Production for Primary Recovery at Different Years

Year	Water				
	Production during the year (m3)	Production during the year (ft3)	Cumulative Production (m3)	Cumulative Production (ft3)	Production Rate at the end of the year (ft3/day)
1	9.526	336.404	9.526	336.404	2.303E-03
2	0.432	15.270	9.958	351.674	5.053E-04
3	0.126	4.439	10.084	356.113	2.044E-04
4	0.055	1.942	10.139	358.055	1.080E-04
5	0.029	1.024	10.168	359.080	6.029E-05
10	0.037	1.307	10.205	360.386	4.039E-06

The simulation shows that using only primary recovery, even after 10 years of production, the well can only produced 7.697MMcuft of methane or around 91% recovery after 10 years. The production by methane using recovery method is by the displaced of methane gas through production of water. When the water production is low, the pressure drop may not be strong enough to displace the methane from the coal. The low production of methane throughout the year may result to the well no longer economically produced. Enhance recovery should be done beginning the third year as clearly observed from Fig. 4.2a and 4.2b, the production started to reach a plateau and after the third year, the methane production after each year is very low.

4.3 GAS INJECTION AFTER PRIMARY RECOVERY

In the previous section, it was shown that using primary recovery only, the reservoir will not obtained 100% methane recovery. It is understandable that after the primary recovery has been conducted in a reservoir, the reservoir property such as pressure and gas in place has changed. Thus, it is interested to see if enhance recovery technique is conducted after primary recovery, can the reservoir achieved 100% recovery just like when the enhance recovery is conducted in the beginning of production? Figure 4.3 shows a comparison between primary recovery, carbon dioxide injection and nitrogen injection after 3 years of production by primary recovery methods. Carbon dioxide, CO_2 and nitrogen, N_2 is individually injected for one year and compared with one year of primary recovery. The red color shows the initial 3 years of primary recovery, the green color is the continued primary recovery after 3 years, the black color represented the production during carbon dioxide injection and the blue color in the simulation shows the production during nitrogen injection.

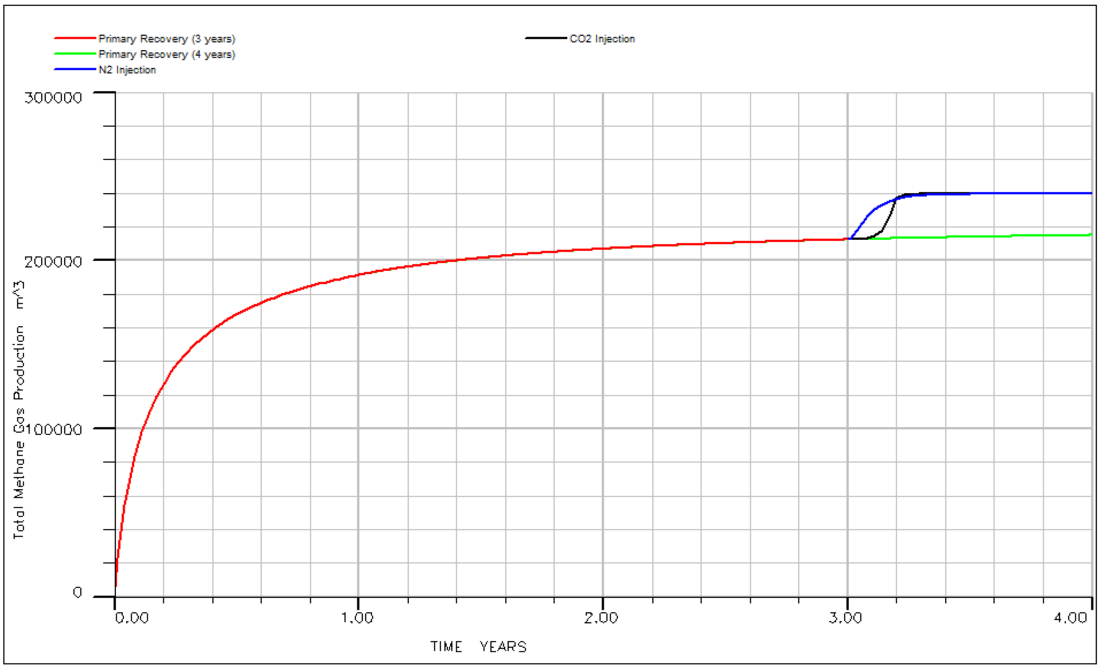


FIGURE 4.3a: Enhance Coal Bed Methane Recovery after 3 Years of Primary Recovery

Fig. 4.3a showed that it is clear that by using carbon dioxide or nitrogen injection after recovery, the well is able to completely produce the remaining methane in the reservoir. For carbon dioxide injection, complete recovery is 85 days after injection while nitrogen injection took a slightly longer time which is 105 days. After this, the well is only producing the injected gas thus has to be abandoned. It is interesting to say that even though the reservoir has low methane content and pressures after 3 years production, the time for complete recovery for each enhance recovery method is almost similar to when injection is introduced in the first day (112 days for carbon dioxide injection and 180 days for nitrogen injection as discussed in Section 4.1). The behavior of the well production is showed clearly in Fig. 4.3b and 4.3c which showed the gas composition in the production well for both injected gas. The red color in the simulation represented the methane mole fraction while the green color shows the injected gas mole fraction.

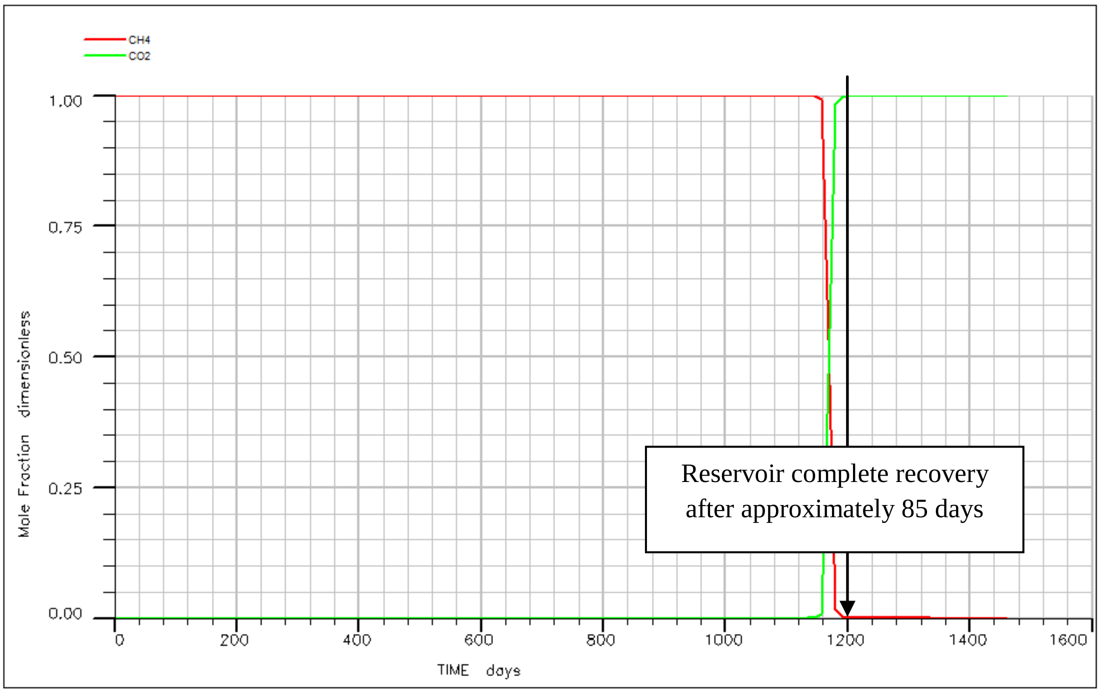


FIGURE 4.3b: Mole Fraction during Carbon Dioxide, CO_2 Injection after 3 years of Primary Recovery

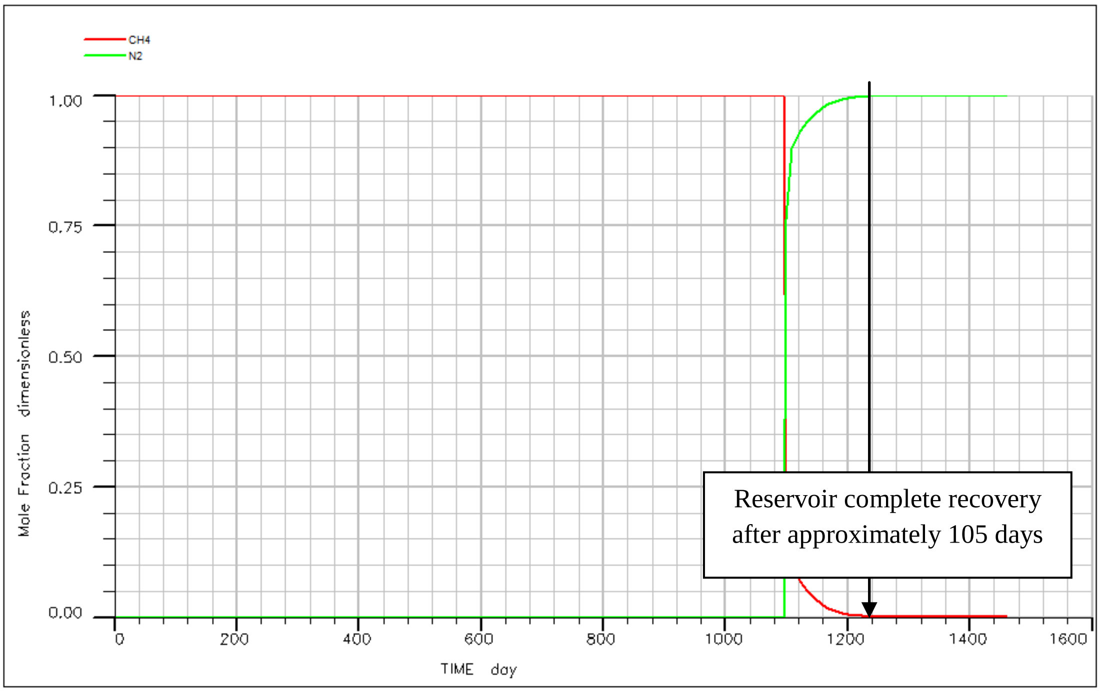


FIGURE 4.3c: Mole Fraction during Nitrogen, N_2 Injection after 3 years of Primary Recovery

4.4 PRIMARY RECOVERY AND ENHANCE COAL BED METHANE RECOVERY IN LARGER RESERVOIR

Even though the reservoir is able to obtain 100% recovery in short time after production during enhance coal bed methane recovery, the size of the reservoir of only 0.625 acres is actually considered as very small reservoir compared to real life reservoir in the world. For example, the Horseshoe Canyon Coal Bed Methane approximately covered a geographical area of 200miles by 50 miles ($6.4x10^6$ acres) and it is estimated to have a potential resource of 500 to 550 Tscf (Bastian, Wang and Voneiff, 2005). Thus, in order make sure that the reservoir production behavior during enhance coal bed methane recovery is similar as when the reservoir is small, the size and number of the simulated grid is increased as shown in Section 3.4.2. It is understandable that it will take longer time for the production to be completed in larger reservoir compared to smaller reservoir, thus the simulation is run for 10 years of production. In the simulation, red color represented methane, CH_4 production rate, the green color represented injection gas production rate and the blue color represented the well total production rate.

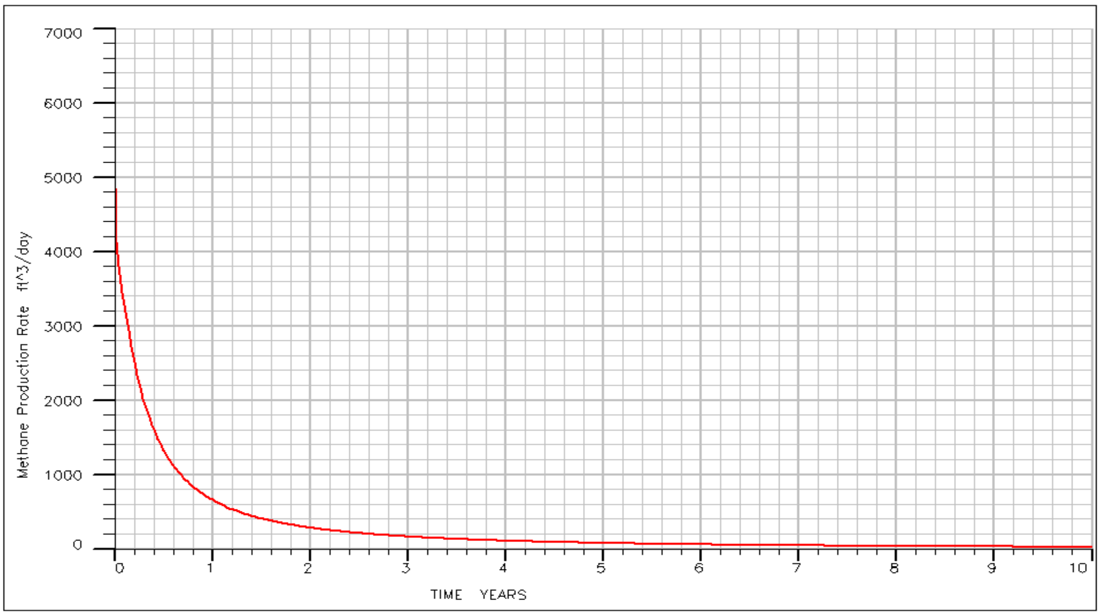


FIGURE 4.4a: Production Rate for Primary Recovery in Larger Reservoir

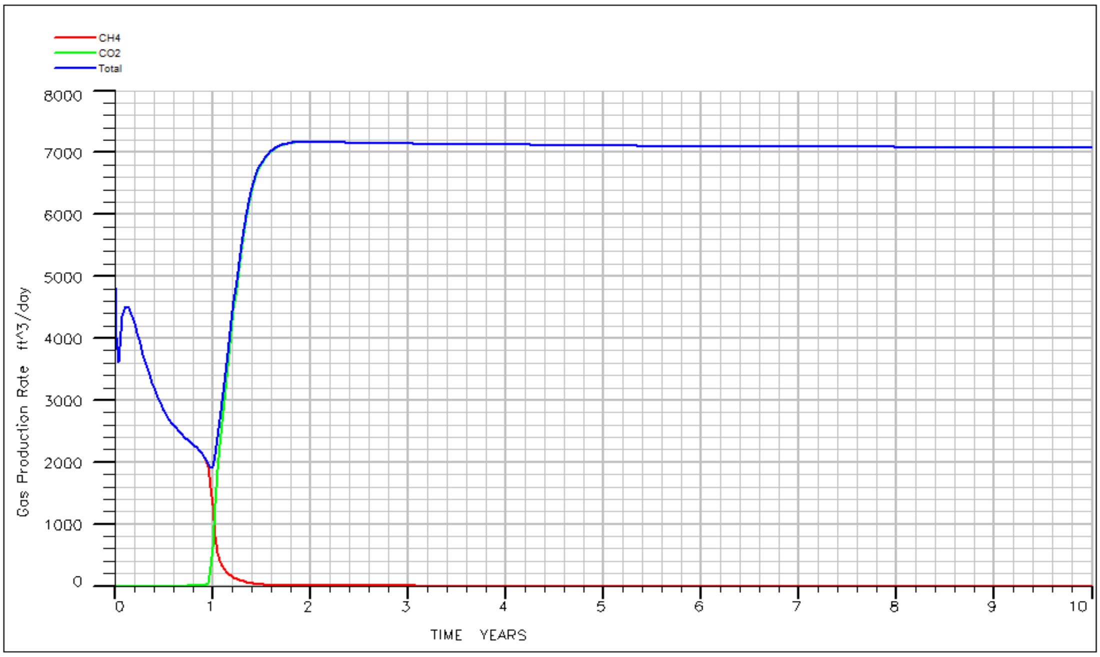


FIGURE 4.4b: Production Rate for Carbon Dioxide, CO_2 Injection in Larger Reservoir

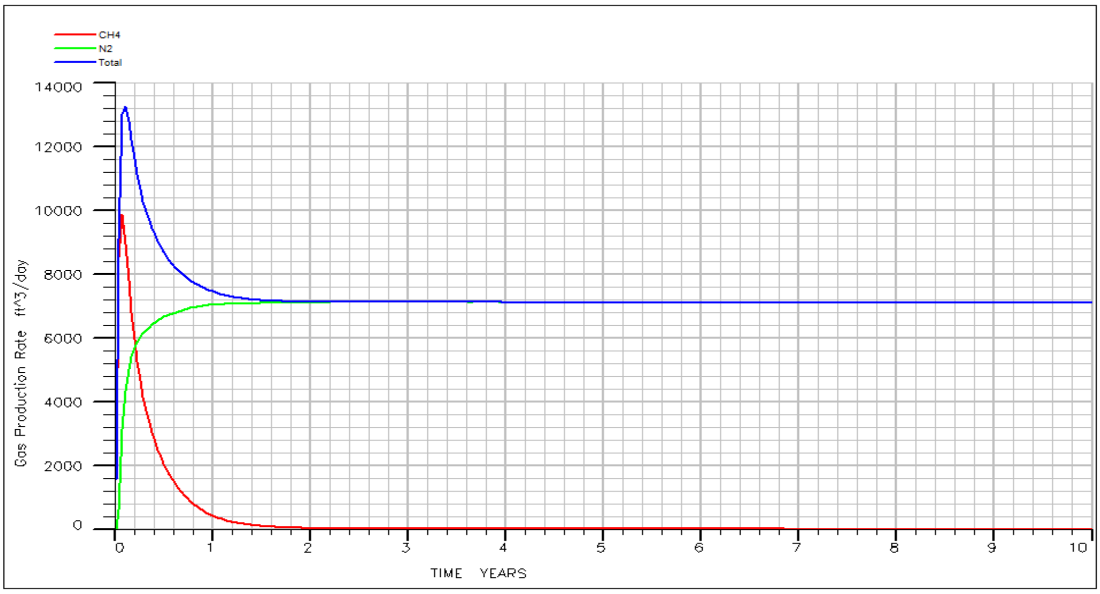


FIGURE 4.4c: Production Rate for Nitrogen, N_2
Injection in Larger Reservoir

Comparing Fig. 4.4a-c with Fig. 4.1a-c, the shapes of both set of figures are very similar showing that regardless the size of the reservoir, the production will behave similarly as predicted. The difference is of course as predicted, an increase in size of the reservoir will resulted to a delay in injection breakthrough and complete recovery will take a longer time. Fig. 4.4d shows the total methane production after 10 years. The red color represented primary recovery, the green color represented carbon dioxide, CO_2 injection and the blue color represented nitrogen, N_2 injection.

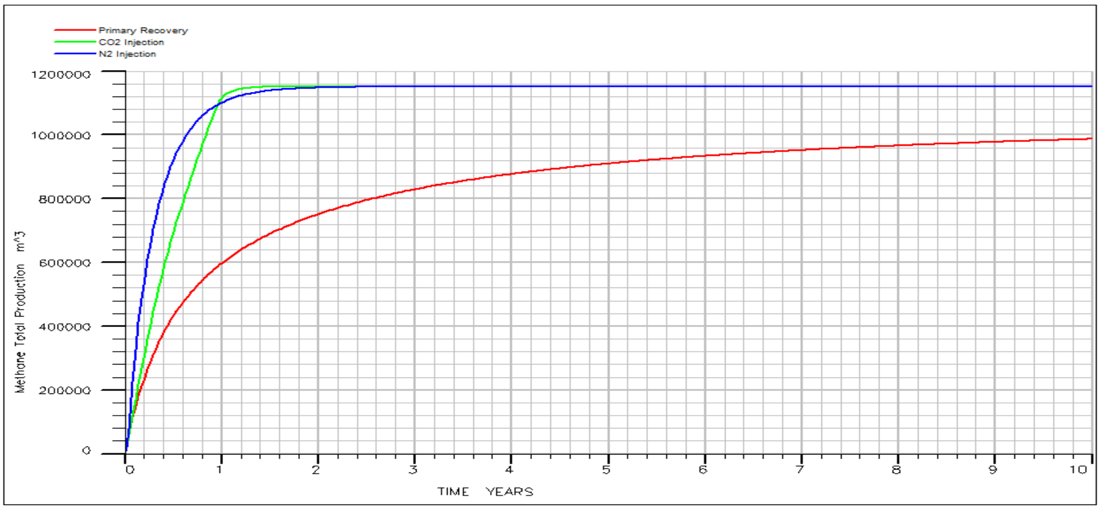


FIGURE 4.4d: Total Methane Production during Primary Recovery, Carbon
Dioxide, CO_2 Injection and Nitrogen, N_2 Injection in Larger Reservoir

From Fig. 4.4d shows that the enhance recovery method either by carbon dioxide, CO_2 injection or Nitrogen, N_2 injection can achieved total methane production of 1151866m^3 (40.68MMcuft) or 100% recovery. Primary recovery however, after 10 years of production has produced 989011m^3 (34.93MMcuft) of methane gas or 86% recovery. With carbon dioxide injection, the production is completed after 600 days of production while with nitrogen injection, the production is completed only after a few days later at 800 days after production. Fig. 4.4e and 4.4f shows the mole fraction of the methane production (red color) and the injected gas (green color) in the production well.

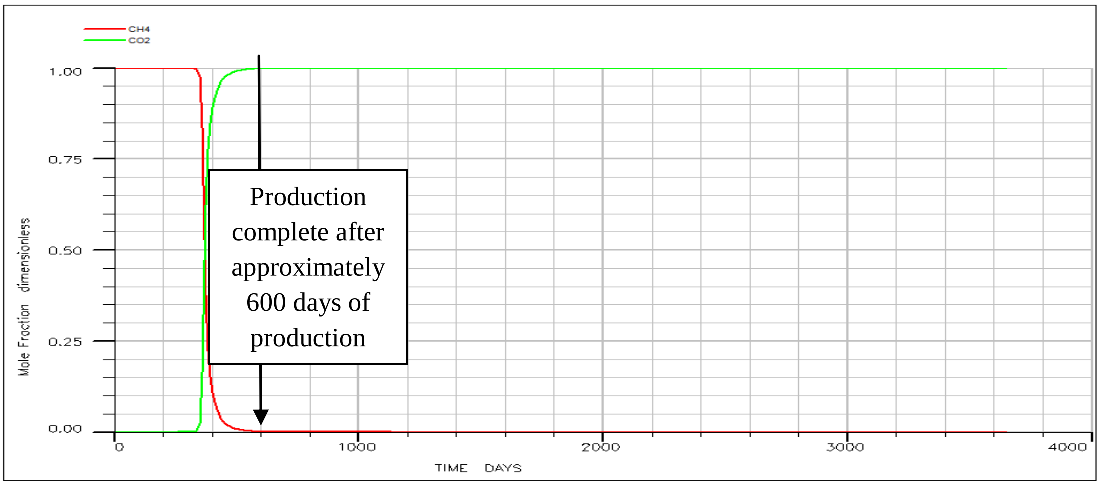


FIGURE 4.4e: Mole Fraction for Carbon Dioxide, CO_2 Injection in Larger Reservoir

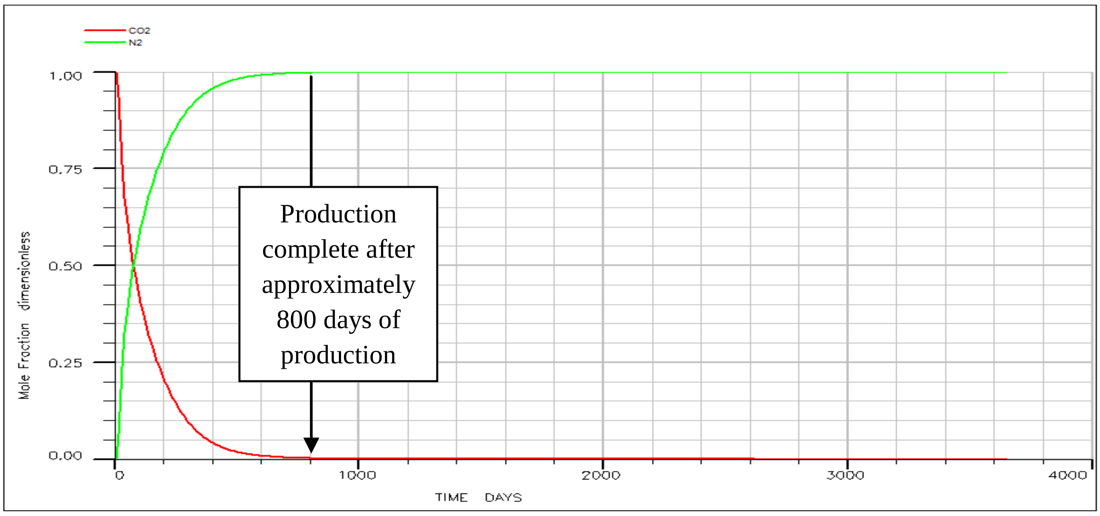


FIGURE 4.4f: Mole Fraction for Nitrogen, N_2 Injection in Larger Reservoir

4.5 COMPARISON BETWEEN ECLIPSE SIMULATOR AND DOT.CBM SIMULATOR

As described previously in Section 3.1, both Eclipse simulator and DOT.CBM simulator can be used to simulate the coal bed methane production. However, the theory or principles behind the simulators are different. The Eclipse simulator designed by Sclumberger is using Black Oil Model (for Eclipse 100) and Compositional Model (for Eclipse 300) in their simulation to calculate and simulate the production behavior of the reservoir. Even though the simulator is originally for single porosity reservoir, a patch program has been design by the software engineers to simulate the dual porosity reservoir of coal bed methane. Both Eclipse 100 and Eclipse 300 can be used to simulate CBM reservoir, however the compositional model provided by Eclipse 300 are more preferred due to smaller number of component in the simulation (CO_2, CH_4, N_2 etc) and using compositional model, the behavior of each individual component can be observed clearly. The simulation conducted for section 4.1 until 4.4 are all have been simulated using Eclipse 300 simulator.

Compared to Eclipse simulator, the DOT.CBM simulator is a simulator design specifically for simulation of coal bed methane reservoir. The simulation is using material balance and also finite element. The simulator however doesn't take into account the position of the well. In other words, each grid used in the simulator represents one production or injection well. The advantage of this simulator compared to DOT.CBM is the ability to integrate real reservoir map into the simulation. This will greatly help in the planning and development of real life coal bed methane reservoir. However, this also result to more information are needed for the simulator to accurately compared to the much simpler Eclipse simulator. Another disadvantage of DOT.CBM simulator is that the simulator can only simulate carbon dioxide injection and cannot be used to simulate other recovery technique such as the nitrogen injection. This is understandable as carbon dioxide injection if much more popular recovery techniques compared to nitrogen injection. The comparison between the result from Eclipse 300 simulator and DOT.CBM simulator simulated using material balance and finite element is shown in Fig. 4.5. The simulation is comparing the primary production using data from Law et al. (2002) as shown in Section 3.41. The blue color represented data simulated from Eclipse 300, the red color is data from DOT.CBM using material balance while the green color also represent data from DOT.CBM however, simulated using finite difference equation and finally the purple color represent the simulation using ECLIPSE 300 but the well position is at the center.

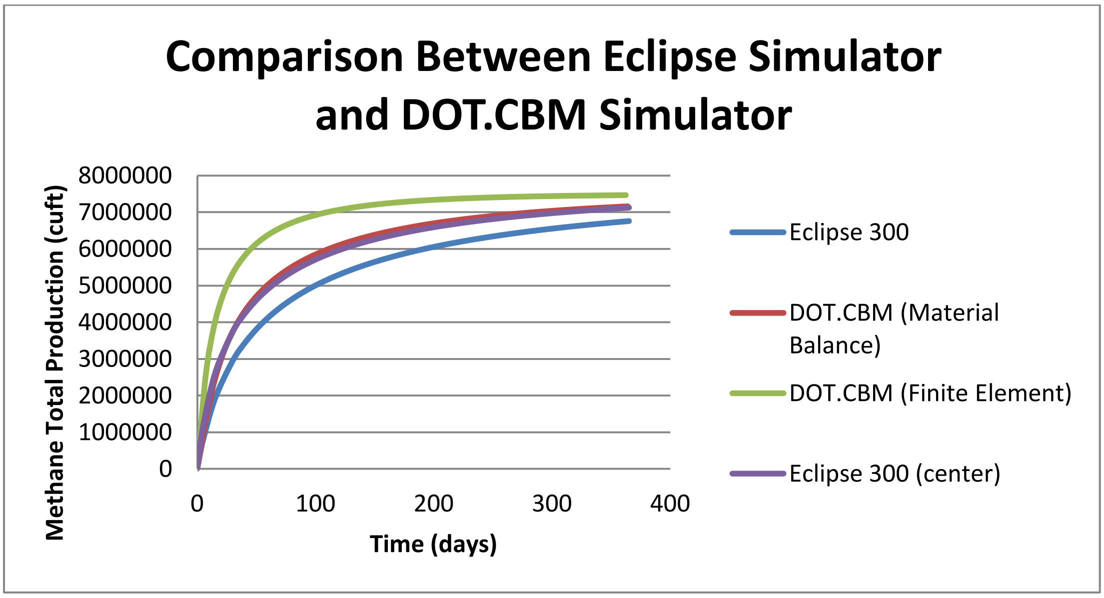


FIGURE 4.5: Comparison between Eclipse Simulator and DOT.CBM Simulator

Assuming that the value obtained from Eclipse is the true value (as most of the simulation in this study is using Eclipse simulator), Table 4.5 shows the comparison between the values obtained from all the simulators.

TABLE 4.5: Comparison between Eclipse Simulator and DOT.CBM Simulator

Simulator	Methane Total Production after 10 years (MMscf)	Percentage Difference (%)
Eclipse 300	7.13	-

DOT.CBM (Material Balance)	7.16	0.42
DOT.CBM (Finite Difference)	7.46	4.63

Fig. 4.5 shows that the reservoir production behavior does show a similar shape during the simulation and the difference in their value is very close as shown in Table 4.5. There are a lot of different between a simulation when the reservoir at the edge of the reservoir (shown in Fig. 4.5 in red color) and at the center of the reservoir (purple color) showing that the placement of well in the reservoir has a big impact on the well production. The simulation also shows that the compositional model and material balance model has a lot of similarities compared to finite difference model. As stated previously, in DOT.CBM simulator, all the well simulated will be assumed in the center of the grid (or in this case reservoir) however, Eclipse simulator allows different position of well to be simulated in the reservoir. Thus, during reservoir development, if there are a lot of wells in the reservoir or if the development team wanted to simulate different well position and arrangement in the coal bed methane reservoir, Eclipse simulator is much preferred. However, if there is only one well or the reservoir has multiple layer with distinguish properties in every layer (heterogeneous reservoir), DOT.CBM simulator is preferred due to its more friendly interface compared to Eclipse simulator.

CHAPTER 5

CONCLUSION AND SUGGESTION

From the result of the simulation, it is clear that recovery from enhance coal bed methane methods is better than only primary recovery as not only it is able to obtain higher recovery, the methods also able to complete the reservoir production in less time. Some may argue that the reservoir used in the simulation are small compared to real life reservoir, however as displayed and discussed in Section 4.4, the production behavior of the reservoir is similar in large reservoir however the time for complete recovery is longer than in small reservoir. The simulation also shows that even if the enhance recovery methods are conducted after primary recovery has been conducted in the reservoir, complete reservoir recovery is still possible. In comparing which of the two enhance recovery methods is better, from the simulation conducted, carbon dioxide injection is better as it is able to obtain total recovery at faster rate than nitrogen injection. Besides that, in the beginning of carbon dioxide injection, the coals absorbed the carbon dioxide and in turn, produced 100% methane gas until breakthrough occurred. Another reason that made carbon dioxide injection more attractive than nitrogen injection is the possibility of reducing green gas effect by storing the carbon dioxide in the coal. This phenomenon has leads to various studies of carbon dioxide storage and sequestration in coal bed methane for example Law et al. (2007) and Lin (2010). For future works, there are few suggestions that should be taken into consideration:

1. Investigate the effect of the wells position in the reservoir to the production behavior.
2. Use data from real life field such as data from the Horseshoe Canyon Coal Bed Methane in Alberta, Canada for simulation.
3. Investigate factors that could leads to early breakthrough during gas injection.

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