Final Report

Final Year Project II

UNIVERSITI TEKNOLOGI PETRONAS

Simulation Study on the Behaviour of N_2 and CO_2 Injection and Their Mixtures on ECBM Recovery

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CERTIFICATION OF APPROVAL

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Approved by,

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(DR. SALEEM QADIR TUNIO)

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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.

JOEAL LIM GUAN CHIN

ABSTRACT

The challenge to produce hydrocarbon from conventional type of reservoirs are getting tougher and tougher. Therefore, there is a need to look into alternatives source of method which is by means of looking into the prospect of unconventional reservoir-production of coalbed methane. There are few differences between conventional and unconventional reservoirs. In conventional reservoir, hydrocarbon is produced first while water acting as an aquifer support will be produced later once the hydrocarbon is depleted. Meanwhile, in unconventional reservoir, water is produced first to depressurize the water pressure (hydrostatic pressure) that is acting on the coal seam so that methane (CH_4) gas is allowed to escape from the coal matrix. Deep coal is able to hold considerable amount of gas but due to different type of coal ranks and high lithostatic load on the coal resulting in very low permeability makes producing gas from such reservoir a challenge. Enhanced Coalbed Methane (ECBM) recovery process is a type of method to improve the recovery process of methane gas after the primary production is declining. One of the method mostly used are the injection of gas to replace the methane gas in the pore matrix. The behavior of injected gases; CO_2 and N_2 alone and their mixtures will be simulated into 2 commercial and one non-commercial fields (San Juan Basin, Powder River Basin, and Balingian Coalfield) will be analyzed and compared. The simulation process will be conducted by using popular and easily available simulators like ECLIPSE simulator. Based on the simulation results, fields that are simulated by injection of pure nitrogen gas yield the highest amount of total recovered methane (CH_4) gas.

ACKNOWLEDGEMENT

In completion of this Final year project, I would like to express my deepest gratitude to all parties that involved in making this project as a meaningful and great achievement for me. Throughout the project timeframe, I have learned a lot of new things and gained so much experience that will be a huge value for me in the future.

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Besides that, I would like to thank the lab assistant and technicians who had helped me to complete the project especially in conducting simulation work. I truly appreciate their help and their sharing of information in order for me to execute the experiment well.

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NOMENCLATURE

Terminologies/ Symbols	Meaning
G	Gas-in-Place, scf
A	Reservoir Area, acres
h	Thickness, feet
$\overline{\rho_c}$	Average In-Situ Coal Density, g/cm^3
$\overline{G_c}$	Average In-Situ Gas Content, scf/ton
G_S	Gas storage capacity, scf/ton
P	Pressure, psia
V_L	Langmuir volume constant, scf/ton
P_L	Langmuir pressure constant, psia
f_a	Ash content, fraction
f_m	Moisture content, fraction
Mcf	Million cubic feet
Bcf	Billion cubic feet
Tcf	Trillion cubic feet
sm^3	Total methane (CH_4) production
sm^3/day	Methane (CH_4) production rates
MJ/kg	megajoule/ kilogram
CBM	Coalbed Methane
ECBM	Enhanced Coalbed Methane

CHAPTER 1 INTRODUCTION

1.1 Background

With the demand for energy grows higher and higher each day, the need for alternative source of energy is very much needed. The challenge to satisfy the needs for energy is getting tougher as the world is already start venturing into the deep water exploration for oil and gas. In the midst of exploring and improving the recovery factor of conventional type of reservoirs, there is also call by some quarters to search for alternatives which is looking into the prospect and potential of unconventional reservoirs.

Unconventional reservoirs is defined by reservoirs that requires different process of extraction and recovery methods of hydrocarbon compared to that of conventional reservoirs. Few examples of unconventional type of reservoirs are tight sand gas, oil/ gas shales, and coalbed methane (CBM).

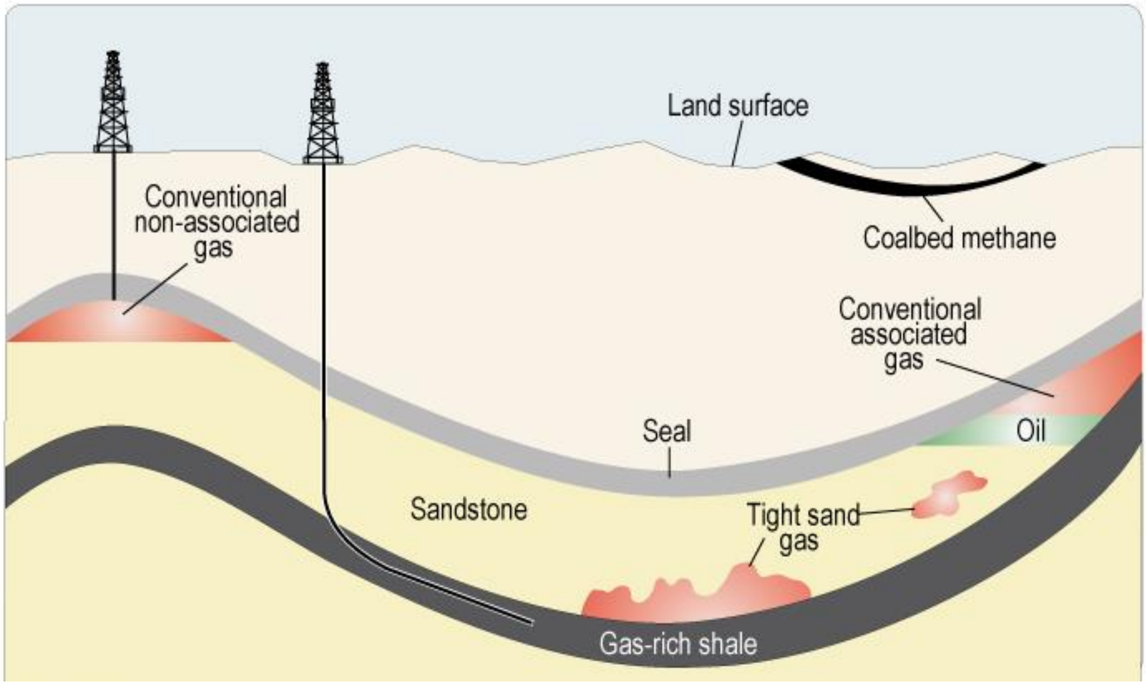

Figure 1.1 Schematic geology showing few examples of conventional and non-convention reservoirs (U.S Energy Information Administration, 2009)

Coals were among the first gas reservoirs to be discovered but is among the most recent one to be exploited. Coal outcrops have been used as solid fuels to early human civilizations but the gas stored within it was left unrecognized due to limited technologies and knowledge (Seidle, 2011).

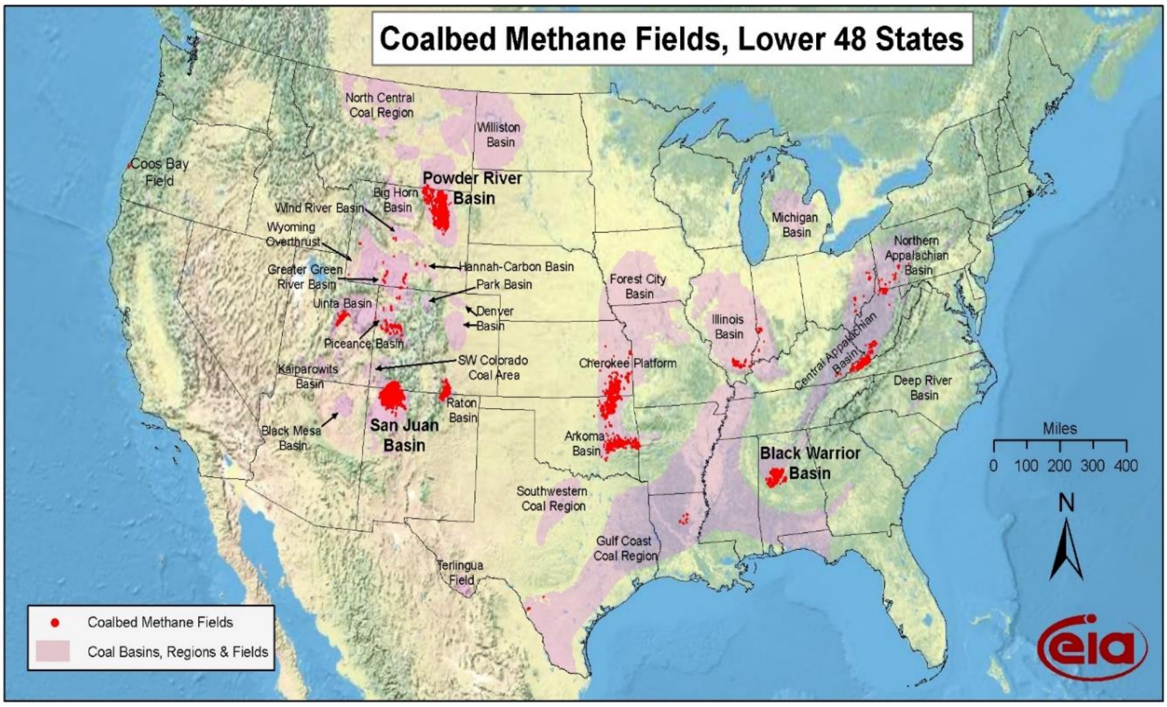

Figure 1.2 Major coalbed methane fields in the United States (U.S Energy Information Administration, 2009)

Coalbed methane gas is defined as the methane gas adsorbed into the matrix of a solid coal and can be produced from seams and cleat within the coal. With the absence of hydrogen sulphide (H_2S) this source of gas can be classified as "sweet gas". Two differences between CBM and conventional reservoirs are the water production and gas-storage mechanisms. In most reservoirs, hydrocarbon are related to porosity due to its storage within the empty pore spaces of the matrix but in coal, it has limited porosity yet it can store up to 6 times more gas than an equivalent volume of sandstone at similar pressure (Schlumberger, 2014).

Traditionally, methane gas from coal are extracted out from the coal to minimize hazards in the mining area. However, methane gas released to the atmosphere proved to be destructive to the environment which contributes to the greenhouse effect that leads to global warming. Carbon dioxide gas is considered as the main cause for global warming, but methane gas although lesser in the atmosphere compared to CO_2 is thirty times more powerful to absorb heat in the atmosphere making it the greatest gas threats that contribute to global warming when compared with any other gas. (Science

Clarified, 2014). With the advancement of technologies and knowledge, major countries around the world like United States, Canada, Australia and Russia began tapping into the potential of CBM.

Chakhmakhchev, 2007 in his "Worldwide Coalbed Methane Overview" mentioned that the success of CBM in North America can be contributed by the factors such as extended coal basins, increasing gas prices, dense distribution network, and little competition with declining conventional gas production.

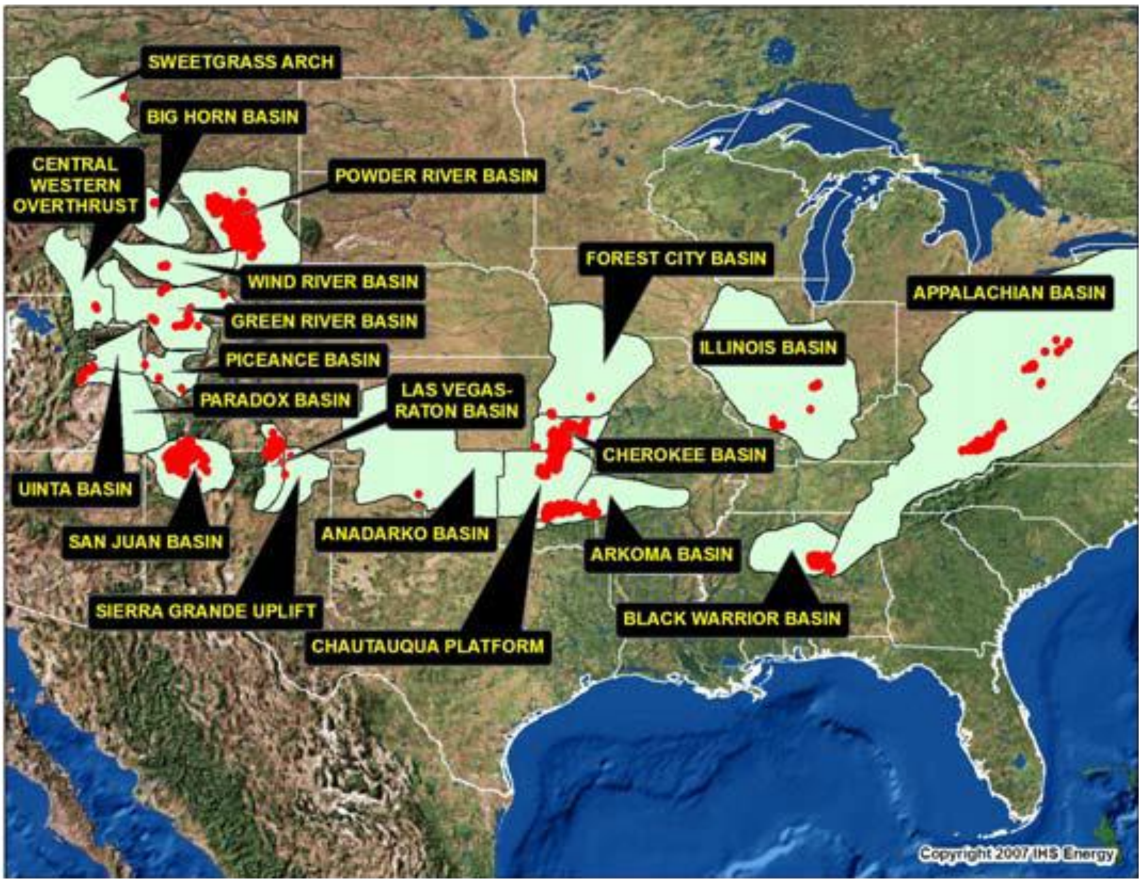

Figure 1.3 2005 CBM drilling in the US (Chakhmakhchev, 2007)

In 2006, it was estimated that the world gas resource from CBM are 143 trillion cubic meters with only 1 trillion currently recovered from the reserves. Figure 1.3 proves that the CBM can be one of the major source for energy. Table below shows the world coal gas resources in 2007.

Table 1.1 Coal reserves for top 5 countries (World Energy Council, 2013)

Country	Reserves (Mt)		Production (Mt)		2011 R/P years
	2011	1993	2011	1993	
U.S.A	237295	168391	1092	858	>100
Russia	157010	168700	327	304	>100
China	114500	80150	3384	1150	34
Australia	76400	63658	398	224	>100
India	60600	48963	516	263	>100
Rest of World	245725	501748	1805	1675	>100
World Total	891530	1031610	7520	4474	>100

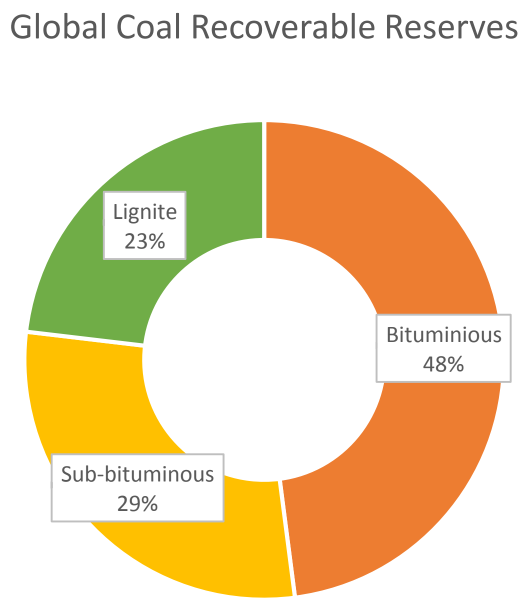

Figure 1.4 Chart showing global coal recoverable reserves categorized by coal ranks (World Energy Council, 2013)

1.2 Problem Statement

Deep coal can hold considerable high amount of gas due to the high hydrostatic pressures but at the same time, higher lithostatic load on the coal will also affect the low permeability of coal. Thus process of extracting and producing from CBM proves a challenged.

One of the method for enhanced coalbed methane (ECBM) is by the injection of gases into the coal to replace the methane gas in the pore matrix. Different type of gases may affect the production rate of methane from the CBM field as different coal ranks have different adsorption capacities and thus behaves differently with the injected gases.

1.3 Objectives and Scope of Study

The main objectives for this research are to analyze:

1. The behavior of injected gases (i.e. CO_2 and N_2 alone) for ECBM recovery
2. The behavior of different mixture of gases (i.e. CO_2 and N_2) for ECBM recovery

In this research, most of the result would be involving simulation of gas injection for three different basins with either ECLIPSE simulator. Reservoir data from each basins would be referred from various published research papers to ensure the integrity and accuracy of the results.

CHAPTER 2 LITERATURE REVIEW

2.1 Coal Formation

In the geologic past, earth is once covered with heavy forestry in swampy areas. These areas are prone to natural processes like flooding. When flooding occurs, these plants tends to be buried underneath the soil. Even if flooding does not occur, the remains of the dead plant will also be buried underneath the soil by the process of weathering like rain. As this process goes on over the years, the forests are buried deeper and deeper resulting them being compressed. Meanwhile, temperature and pressure rose greatly as the plants are buried deeper into the earth. The chemical properties of mud and acidic water will then protect the plants from the process of biodegradation and oxidation. Eventually these plants will be accumulated layer upon layers and formed a soggy, dense material called peat. (University of Kentucky, 2012)

Peat deposits can be varied. These deposits can be varied from various dead plants parts like roots, bark, branches and et cetera. When this peat are buried by sediments, the compression exerted by the sediments along with high pressure and temperature and prolong period of time, will slowly breaks and alter the complex hydrocarbon compound of peat to become coal. Products due to gaseous alteration are usually eliminated from the deposits and the deposits become more carbon-rich as more elements are eliminated. As coal contains mainly carbon, this process of alteration of dead plants and vegetation into coal is called coalification. (University of Kentucky, 2012)

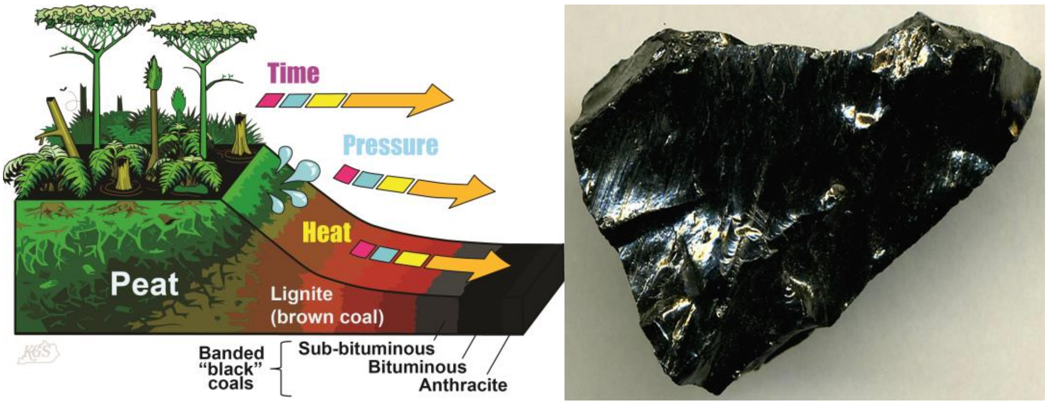

Figure 2.1 Figures showing the summarized steps of how coal is formed and a sample of anthracite coal (University of Kentucky, 2012)

2.2 CBM vs. Conventional Reservoir

Conventional Reservoir

According to Schlumberger Oilfield Glossary, the reservoir and fluid characteristics of conventional reservoir usually allow the flow of hydrocarbon easily into the wellbores. In conventional reservoir, hydrocarbon produced from source rock is normally migrated easily through a porous media until it is stopped by overlying rock layers such as sandstone thus forming an oil and gas accumulation reservoir. However, in the geologic formation for CBM, the gas produced is just stored at the source rock due to the impermeable properties of the rock.

Rogers et al, 2007 summarized that there are 3 mechanism steps involved for gas in coal. The first mechanisms is the gas escaping from the coal matrix by the process of desorption. After that, diffusion of the gas through the micropores, and lastly since there are presence of water (multiphase), Darcy equation is used to explain the flow of the gas through the fracture network to the wellbore.

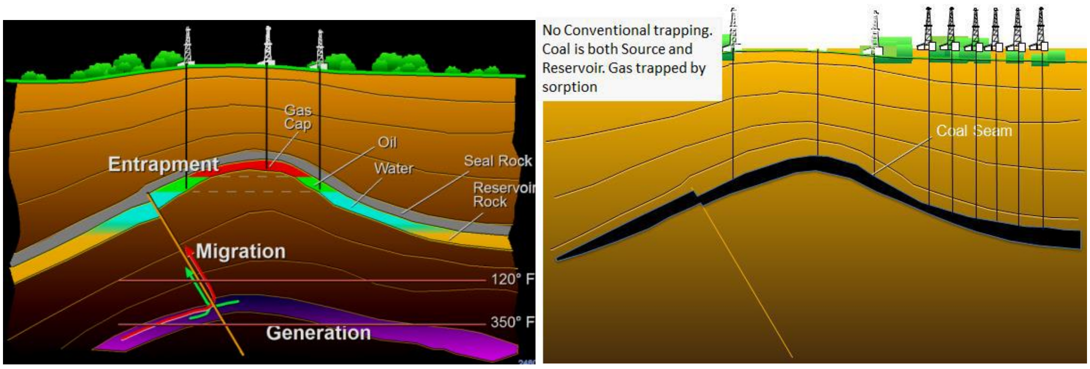

Figure 2.2 Left figure shows the trapping of hydrocarbon in conventional reservoir whereas right figure shows no conventional trapping. Coal is both source and reservoir. Gas is trapped by adsorption. (Peacock, 2013)

Another author, Aminian in his “Coalbed Methane – Fundamental Concepts” has made comparison between CBM and conventional gas reservoir based on their reservoir characteristics.

Table 2.1 The differences of a CBM field compared with the conventional gas reservoirs (Aminian)

Characteristics	Conventional	Unconventional
Gas Production	Gas is produced in the source rock and then migrates into the reservoir	Gas is generated and trapped within the coal
Structure	Randomly-spaced fractures	Uniform-spaced cleats
Gas Storage Mechanism	Gas is stored in the porous spaces in the rock	Gas is adsorped to the coal matrix
Transport Mechanism	Pressure Gradient (Darcy's Law)	Concentration Gradient (Fick's Law) and Pressure Gradient (Darcy's Law)
Production Performance	The rate of gas production will be high in initial production and slowly decreases with the increase in production of water	Vice versa compared to conventional. Water need to be produced first then only gas can be produced (de-watering)

Rogers et al., 2007 also did a comparison between conventional and CBM reservoirs which is different to that of Aminian.

Table 2.2 Coalbeds and Conventional Reservoirs Compared (Rogers, Ramurthy, Rodvelt, & Mullen, 2007)

Conventional Gas	Coalbed Methane (CBM)
Darcy flow of gas to wellbore	Diffusion through micropores by Fick's Law
	Darcy flow through fractures
Gas storage in macropores; real gas law	Gas storage by adsorption on micropore surfaces
Production schedule according to set decline curves	Initial negative decline
Gas content from logs	Gas content from cores. Cannot get gas content from logs
Gas to water ratio decreases with time	Gas to water ratio increases with time in later stages
Inorganic reservoir rock	Organic reservoir rocks
Hydraulic fracturing may be needed to enhance flow	Hydraulic fracturing required in most of the basins except the eastern part of the Powder River Basin where the permeability is very high. Permeability dependent on fractures.
Reservoir and source rock independent	Reservoir and source rock same
Permeability not stress dependent	Permeability highly stress dependent
Well interference detrimental to production	Well interference helps production. Must drill multiple well to develop

2.3 Definition of Coalbed Methane (CBM)

Methane gas is one of the most widely used natural gas around the globe. CBM defined as the methane gas found in the coal seams. Unlike the conventional gas reservoirs, the practice of extracting methane from coalbed is relatively new. Traditionally, methane gas in mining area are released into the atmosphere as a method to reduce hazard in the mining area for coal deposits (Science Clarified, 2014). With the declining in conventional gas volume, efforts by government and higher technologies and knowledge has helped the oil and gas community to starts tapping into the potential of unconventional CBM fields like in San Juan Basin and Powder River Basin in United States and Qinshui Basin in China.

CBM reservoirs are naturally fractured reservoirs with the fractures as cleats filled with water. Hydrostatic pressure by the water in the cleats is responsible in holding the gas capped in the pore matrix. This pressure eventually acted as an unconventional seal to prevent the gas from escaping the reservoir (Seidle, 2011).

2.4 Mechanism of CBM

<u>Storage Mechanism of CBM</u>

Unlike conventional gas reservoir, coalbed methane has very low porosity and permeability. As explained earlier, methane gas produced from the source rock are stored in the coal matrix by the process of adsorption.

Water is initially produced by CBM wells and they usually saturates the coal cleats and fractures acting as a trap to the methane gas produced. The high amount of hydrostatic pressure exerted by the water continue to trap the gas inside the coal matrixes. Lowering the hydrostatic pressure in the coal seam will ease the release of gas out from the coal seam. As long the pressure in coal does not overcome the hydrostatic pressure of the water, gas will always remained trap in the coal bed matrix. (ALL Consulting & Montana Board of Oil and Gas Conservation, 2004)

<u>Production of CBM</u>

Keith et al. (2003) suggested that presently there are 2 methods that is commonly used to predict how much methane gas that can be recovered from a coalbed.

The first method is by analyzing the core sample of the coal seam. By calculating the per unit volume of methane gas released from the core sample, the calculation is then used to compared to actual size of the CBM field. In this method, numerous cores will be drilled around the region of the coal to measure the methane gas released so that the estimation for the available gas in the region will be more accurate. However, this method proved unreliable as the process to get the core samples will creates unnecessary disruption affecting the coal seam making the measurement for the methane gas released inaccurate. This method is also expensive and not every region in the CBM field will be drilling and explored. (Keith, Bauder, & Wheaton, 2003).

Second method involved more tedious process but yield better result. The coal information and feasibility studies of the development of the CBM field must be known and calculated thoroughly. Taking Powder River Basin as an example, the local geology department there said in order to predict the recoverable amount of methane gas from a field, few important requirements must be fulfilled. The requirements stated by Keith et al. “are:

- It is a potential reserves if range of 50 to 70 cubic ft per ton of coal is produced
- Coal seam thickness must be more than 20ft for the CBM extraction to be economical at 50 cubic feet per ton of coal
- The chemical properties for the water in the coal seam must be dominantly in sodium bicarbonate
- The depth where the coal seam is buried in must have sufficient hydrostatic pressure from the water to ensure the gas do not desorb out into the atmosphere”

Once the requirements are fulfilled, the recoverable methane gas is then calculated by getting the product of the total coal in the region with the total number of methane per ton of coal.

Aminian also mentioned without knowing the storage capacity and gas content, it is not possible to estimate the gas reserves. These two properties can only be measured directly from the core sample. By the process of sorption, methane gas is stored and released in the coalbed methane reservoirs. Value of total initial adsorbed gas in CBM reservoir is usually described by the equation below:

$$\textit{(Equation 2.1)}\quad G = 1359.7\, Ah\overline{\rho_c}\,\overline{G_c}$$

Since conventional rules does not apply in gas in coal due to difference in gas storage mechanism, desorption isotherm is used to define the pressure-volume relationship.

$$\textit{(Equation 2.2)}\quad G_s = \frac{V_L P}{P_L + P}$$

However, the equation 2.2 have to be modified to consider the coal rank, temperature and coal moist content so that it is valid for application in the field. Thus the Langmuir equation is modified to:

$$\textit{(Equation 2.3)}\quad G_S = (1 - f_a - f_m)\frac{V_L P}{P_L + P}$$

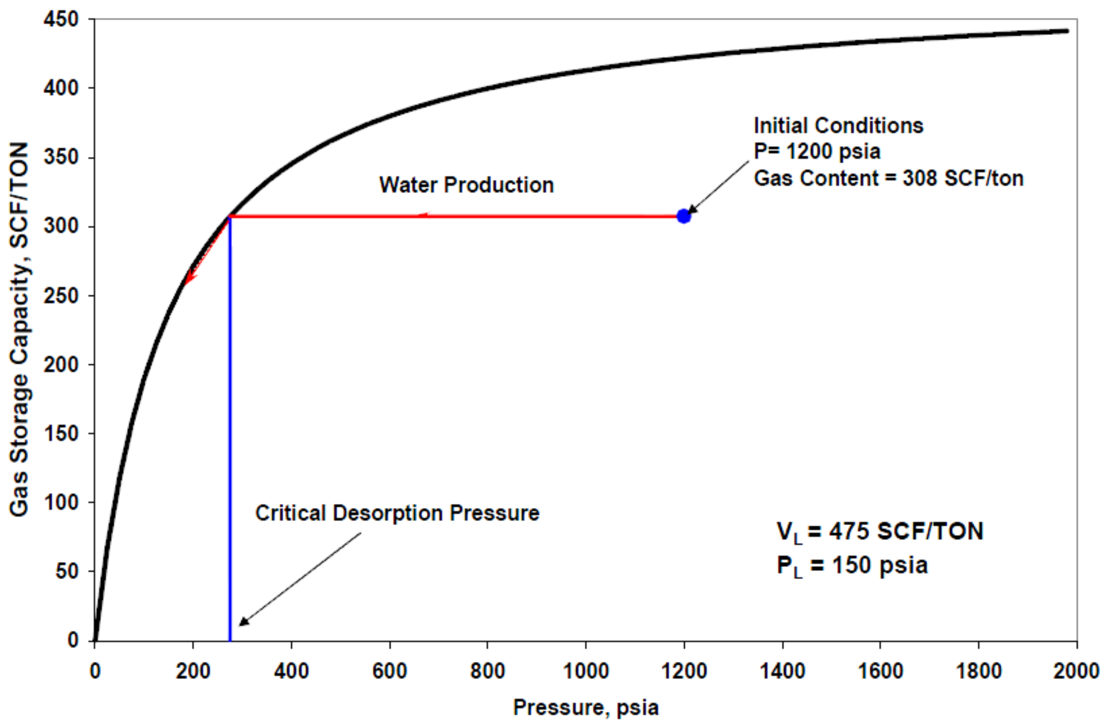

Figure 2.3 Typical Langmuir Isotherm (Aminian)

2.5 Recovery of CBM

<u>Primary Recovery</u>

Primary recovery of hydrocarbon is recovery without any usage of external help (e.g. injection of gas or water). The primary process depends on the natural forces such as gravity and pressure to help drive hydrocarbon from the reservoir out into the wellbore.

This process will continue until the natural support is no longer sufficient to drive out the hydrocarbon (Looper, 2014).

Basically, primary recovery of CBM is by reducing the hydrostatic pressure of the water saturating in the coal seams. This can be achieve by firstly produce the water out from the CBM reservoir. When hydrostatic pressure of water is decreased, methane gas is then freely able to desorb out from the pore matrix of the coal into the wellbore. As the dewatering process is very expensive, if there is too much water in the reservoir, the production of methane gas from such field can be uneconomical.

Burns and Lamarre in Drunkard's Wash Project (1997) which is also cited by Tunio et al. (2011) mentioned that there are cases where "if CBM field is near to a conventional reservoir i.e. the Drunkards Wash area in Price, Utah, once completion, gas flows freely without the need of dewatering".

Secondary Recovery

When the first phase of production starts to decrease, there is a need to inject gases into the coal seams to recover methane gas. This process is then called secondary recovery.

In the industry, two most popular gases to be used in the secondary recovery is CO_2 and N_2 due to their chemically unreactive capabilities. The purpose for the injection is so that the injected gas will replace the original gas in place in the coal seams. If there is presence of sealing cap rock (a type of stronger and harder rock overlying a weaker rock), then the injected gas would be sealed there permanently (Mazzotti, Pini, & Storti, 2008). In the same research, Mazzotti mentioned that due to CO_2 high affinity for coal, injected CO_2 will displace easily the methane gas produced and enhanced its production recovery. He also suggested that in the future, co-existence usage of CO_2 and N_2 can be done to study the ECBM recovery.

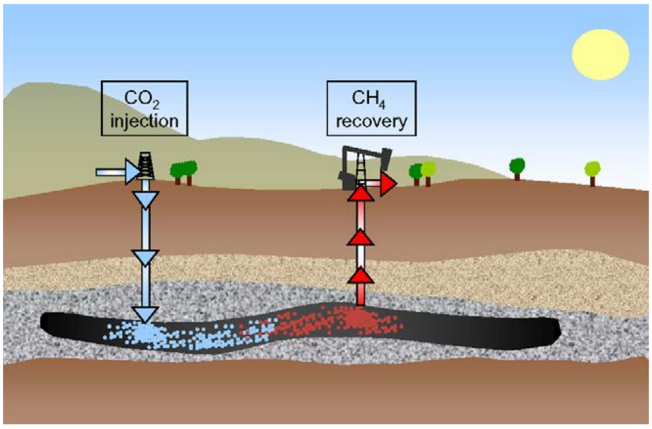

Figure 2.4 General schematic showing an ECBM operation where injection of gas (CO_2) from a power plant will help replace/displace the original CH_4 in the reservoir (Mazzotti et al., 2008)

2.6 Basins

(A) San Juan Basin

Spanning over 100 miles wide and 140 miles long, San Juan Basin is located in north-western New Mexico and south-western of United States is one of the top producer CBM fields around the globe. San Juan Basin's Fruitland CBM fields has started during late 1970s from nearly no production until around one trillion cubic feet of gas (TCFG)/year in the presence (Fassett, 2010).

In 2000, San Juan Basin has produced a total of 0.78Tcf of gas that translates to 4% of United States natural gas production and 80% of CBM production (ALL Consulting & Montana Board of Oil and Gas Conservation, 2004).

Rogers et al. (2007) said that there are several attributes that explain the high success rate of the CBM field which are favourable:

- Coalseam thickness
- Permeability
- Gas content
- Depth
- Coal rank

Table 2.3 San Juan Basin Description (Rogers, Ramurthy, Rodvelt, & Mullen, 2007)

Depth of Coal (ft)	Fruitland: Outcrop to 4200 ft Menefee: Outcrop to 6500 ft
Net Coal Thickness, Max. (ft)	110
Individual Coalseam Thickness (ft)	50 (Max.), 8 to 15 (Avg.), Fruitland 15 (Max.), 4 (Avg.), Menefee
Gas Content (scf/ton)	300 to 609
Gas In Place (Tcf)	88
Coal Rank	hvBb to lvb
Ash Content (%)	8 to 30
Sulfur Content (%)	<1.0
Moisture Content (%)	2 to 10
Permeability (md)	1.5 to 50

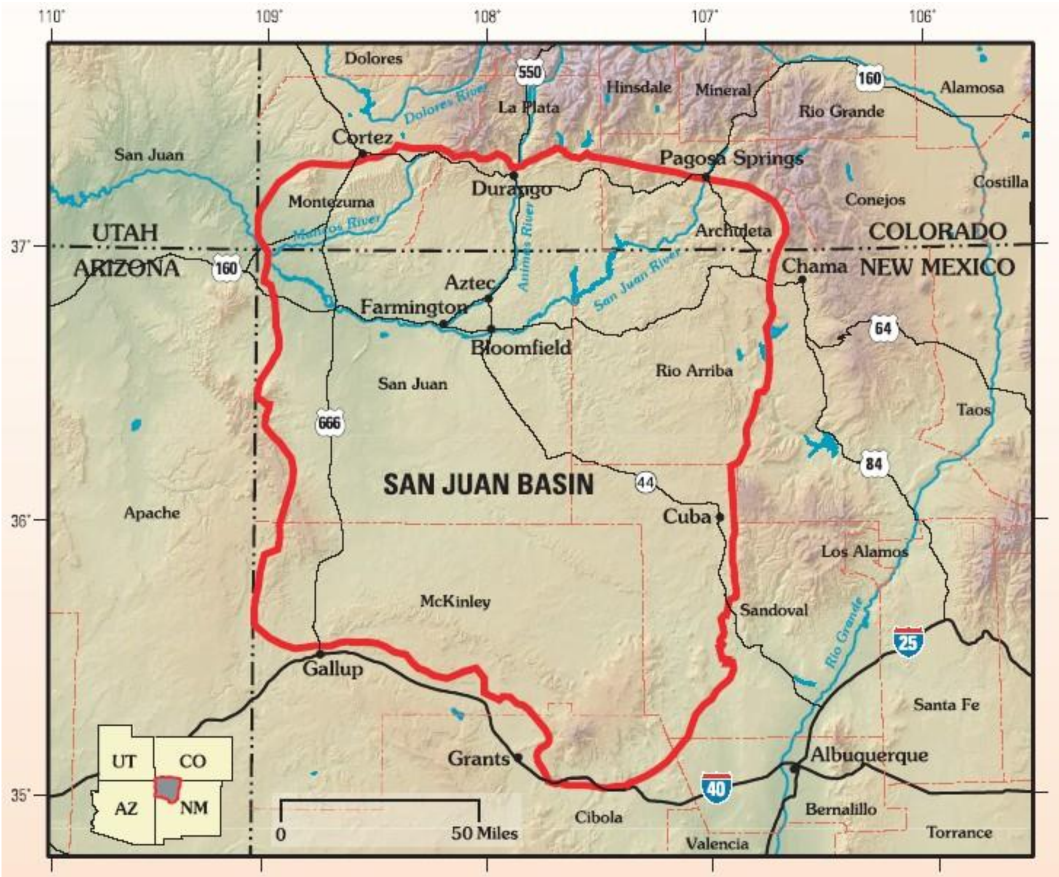

Figure 2.5 Location of San Juan Basin in the United States (Rogers et al., 2007)

(B) Powder River Basin

Located at north-eastern Wyoming and south-eastern Montana, the major production of CBM field here is known as Powder River Basin which is an elongated basin covering about 25800 sq miles. It is believed that 50% of Powder River Basin have the potential to be CBM producer. (ALL Consulting & Montana Board of Oil and Gas Conservation, 2004)

According to Swindell (2007), in 2005 a total of 341 Bcf of production of CBM has been recorded at the state of Wyoming. This value is accounted to nearly 2% of total United States natural gas reserves. CBM production from Powder River within a period of 14 years has increased nearly 10 times drastically to approximate 1700 Bcf annually in year 2004 when compared to only 190 Bcf back in the year 1990 and its cumulative CBM production is approaching to 2 trillion cubic feet (Tcf) in 2006 with reserves estimated to be about 39 trillion cubic feet.

Table 2.4 Powder River Basin Description (Rogers, Ramurthy, Rodvelt, & Mullen, 2007)

Depth of Coal, Max. (ft)	Outcrop to 2500
Net Coal Thickness, Max. (ft)	170 to 300
Individual Coalseam Thickness, Max. (ft)	50 to 220
Gas Content, scf/ton	74 (Max.)
Gas in Place, Tcf	30 to 39
Coal Rank	Lignite to sub-bituminous
Ash (%)	5.1
Sulfur	0.34
Permeability	Up to 1.5 Darcy

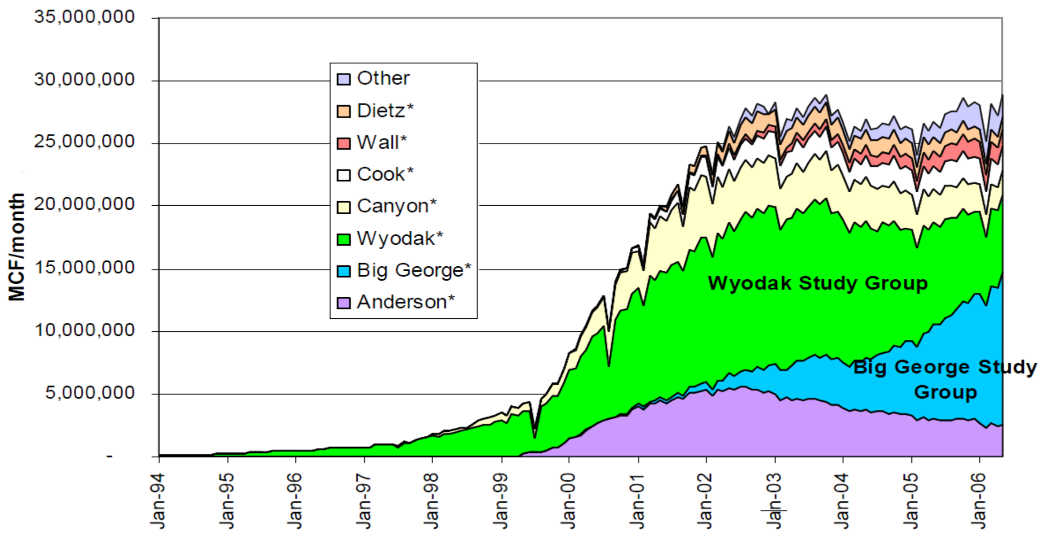

Figure 2.6 Showing total Powder River Basin CBM Production (Swindell, 2007)

(C) Balingian coalfield

Comparing with major CBM producer like San Juan and Powder River, this field is not a commercial CBM field, however it is chosen in this research to study its prospect as a future commercial CBM producer. According to Tunio et al., (2011) Balingian coalfield is located at state of Sarawak, Malaysia, where this coalfield is one of the 4 major coal fields around the region. It is estimated that Balingian Coal Basins to have roughly 400 million to 2000 million cubic meter of coalbed methane gas in place (Gee & Abdullah, 2010).

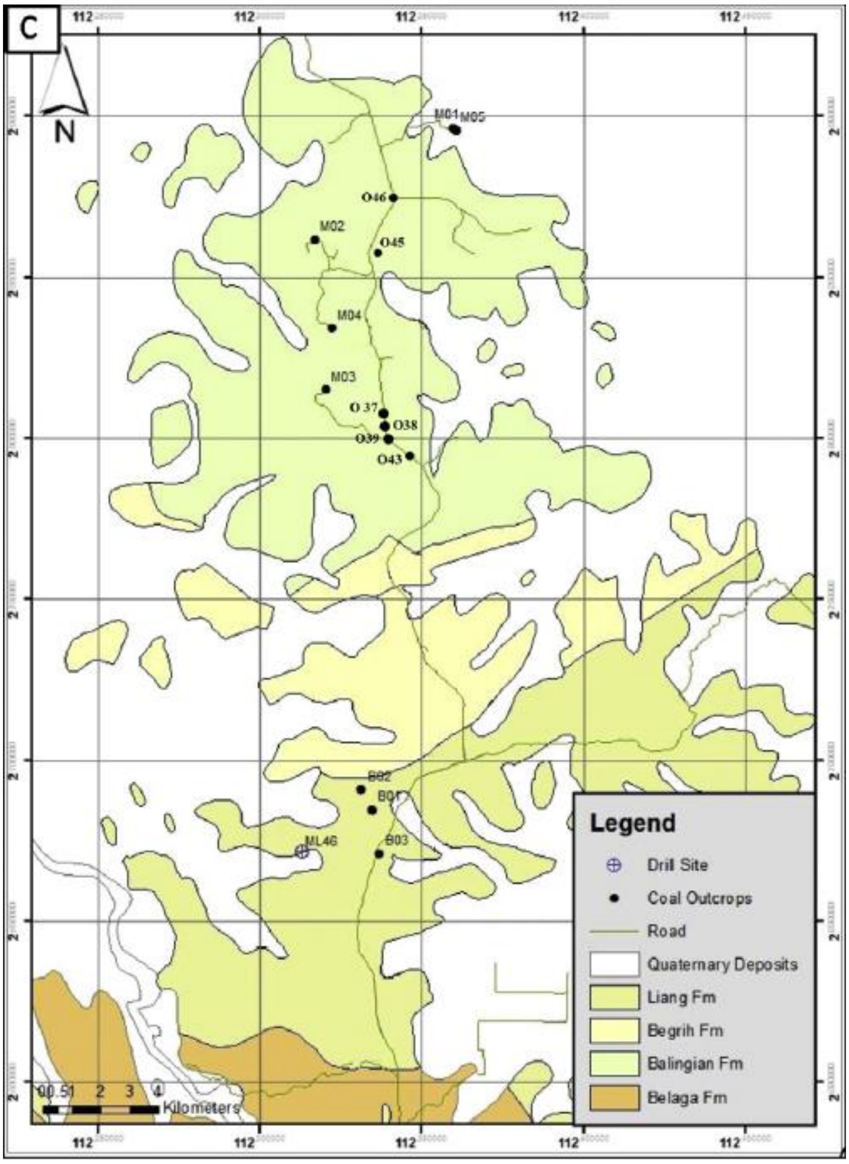

Figure 2.7 Map showing distribution of the Balingian and Liang Formations around Balingian and Mukah coalfields, northwest Sarawak, Malaysia (Hakimi, Abdullah, Sia, & Makeen, 2013)

Table 2.5 Information of the Coalfield (Tunio, Chow, Irawan, & Kong, 2011)

Parameters	Value
Area, acres	1505.9
Thickness, ft	93.133
Average in-situ density, g/cm^3	1.3350
Average in-situ gas content, scf/ton	374.62
Gas-in-place, Bscf	95.370

Table 2.6 Analysis of the coal (Tunio, Chow, Irawan, & Kong, 2011)

Analysis	Balingian Coal
Total Moisture (dry)	23.25%
Total Ash (dry)	5.95%
Sulphur content (dry)	0.48%
Volatile Matter (dry)	48.9%
Gross caloric value (dry)	25.92MJ/kg
Rank	Lignite
Vitrinite Reflectance (%Ro)	0.32%

CHAPTER 3 METHODOLOGY

3.1 Methodology Diagram

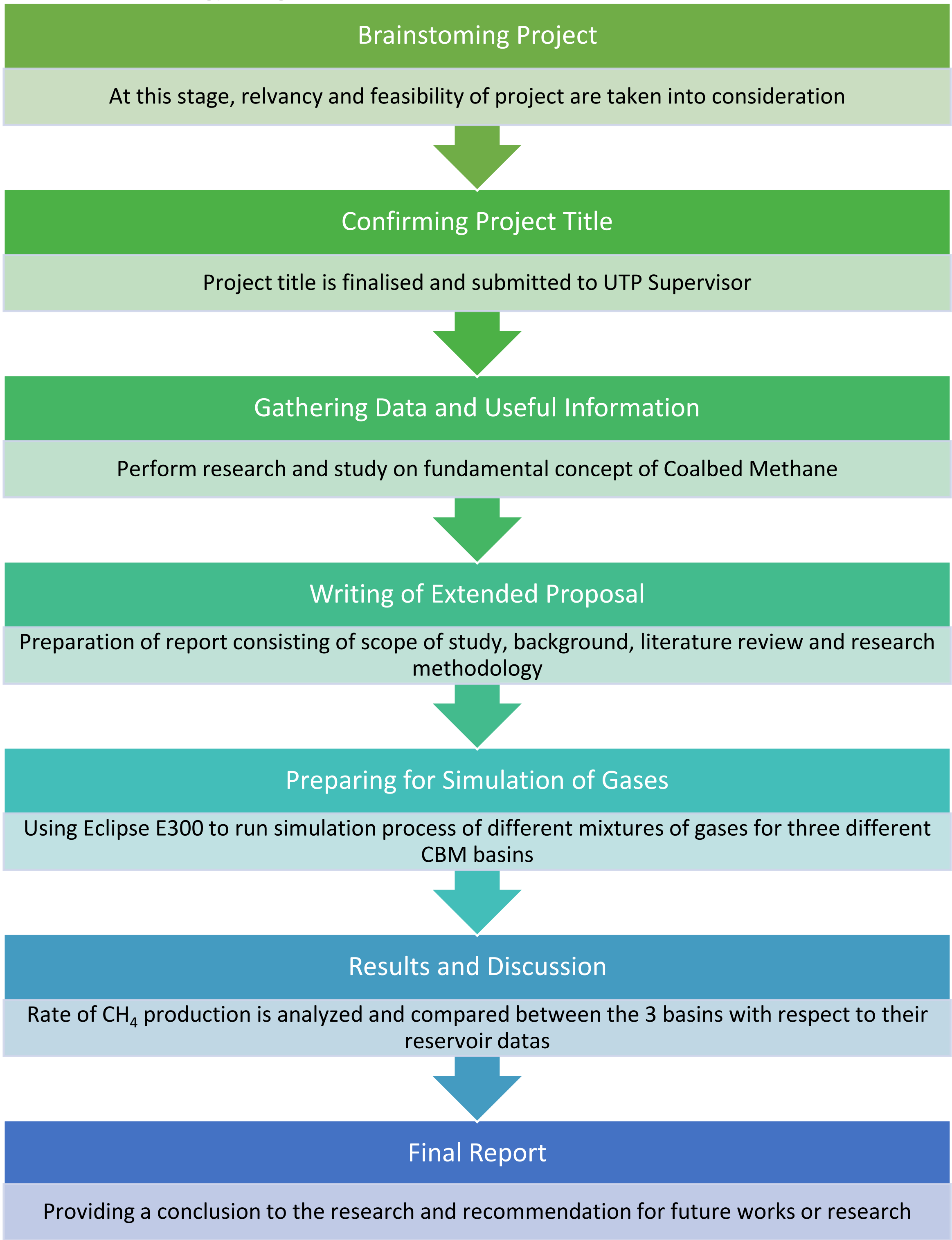

Figure 3.1 Research Methodology

3.2 Project Activity

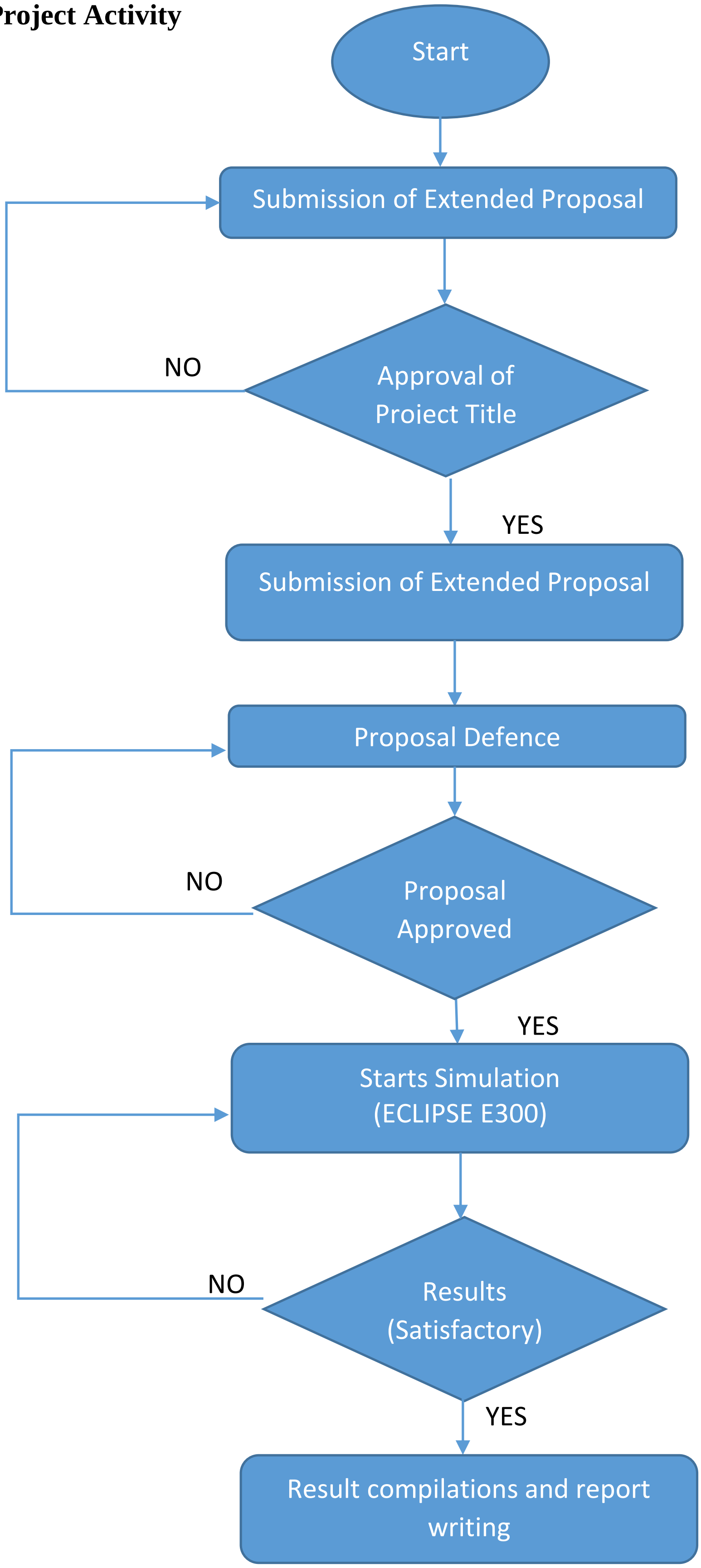

Figure 3.2 Project Activity

3.3 Simulation of CBM

There are a lot of commercial simulators like ECLIPSE, CMG GEM and et cetera to simulate the production of CBM. Law et al. (2002) emphasised that a lot of criteria must be taken into consideration before choosing a suitable simulator for CBM simulation. Few of the considerations include:

- Dual porosity nature of coalbed
- Possibility of multiphase flow
- The diffusion and sorption process for single gas component (i.e. methane gas only)
- Possibility for the shrinkage in size of the coal matrix by the process of gas desorption

When a more complex mechanism are involved, such as when carbon dioxide gas is concerned in the Enhanced Coalbed Methane recovery process, there are considerations that the simulators have to take into account so that it can yield more accurate results. (Law, Meer, & Gunter, 2002)

The considerations are:

- The adsorption of carbon dioxide gas will cause the swelling of coal matrix
- Stress that cause compaction and dilation of the fracture system
- Presence of multiple gas component and their diffusion and adsorption/desorption
- Possibility of non-isothermal adsorption because of the temperature difference between that occurs between the injected carbon dioxide gas and the coalbed
- Presence of water and its flow along the empty space between the fracture and the coal matrix

In this research 3 fields; 2 commercials CBM basin and one non-commercial coalfield will be simulated with:

1) Pure carbon dioxide and pure nitrogen gas
2) Different composition of carbon dioxide and nitrogen

The rate of production of methane gases from these 3 fields will be tabulated and discussed.

Table 3.1 Simulation of different composition of gas for 3 different basins

Basins	**Simulation Cases**	
	Cases	**Composition**
San Juan	Case 1	100% CO_2
	Case 2	100% N_2
	Case 3	25% CO_2 and 75% N_2
	Case 4	75% CO_2 and 25% N_2
	Case 5	50% CO_2 and 50% N_2
Powder River	Case 1	100% CO_2
	Case 2	100% N_2
	Case 3	25% CO_2 and 75% N_2
	Case 4	75% CO_2 and 25% N_2
	Case 5	50% CO_2 and 50% N_2
Balingian Coalfield	Case 1	100% CO_2
	Case 2	100% N_2
	Case 3	25% CO_2 and 75% N_2
	Case 4	75% CO_2 and 25% N_2
	Case 5	50% CO_2 and 50% N_2

3.3 Key Milestone

FYP 1

Week 1 - 3 Selection of Project

- Discussion with Supervisor on a suitable project title
- Determining research method; stimulation or simulation

Week 4 - 6 Preliminary Research Work

- Gathering of information and data from various research papers
- Fundamental Concept of CBM, Background, Scope of study, Objectives, Literature Review
- Producing Extended Report

Week 8 Submission of Extended Proposal

- Handing in completed extended proposal to both supervisor and course coordinator

Week 9 Proposal Defense

- Presentation of submitted title

Week 10 - 12 Project Work Continues

- Continuation of the project

Week 13 - 14 Submission of Interim Draft and Report

- Submission for the finalized report for this semester

FYP 2

Week 1 - 6 Continuation of Project Work

- The second phase of the final year project which is the methodology chapter
- Starts of simulation activities using Eclipse E300

Week 7 Submission of Progress Report

- Handing in completed progress report to both supervisor and course coordinator

Week 8 - 12 Continuation of Project Work

- Simulation activity is continues with added parameters
- Amendment to the report after advice from supervisor

Week 10 Pre-Sedex

- Presentation of poster to internal examiner

Week 12 Submission of Dissertation and Technical Paper

- Handing in final report of FYP to external and internal examiner
- Handing in technical paper to supervisor

Week 13 Viva Presentation

- Presentation of project work to external and internal examiner

Week 15 Submission of Project Dissertation

- Handing in two copies of final project work (hardbound) to course coordinator

3.4 Gantt Chart (FYP1 and FYP2)

Joeal Lim Guan Chin Matrix ID: 15115 Petroleum Engineering, Final Year 1st Semester FINAL YEAR PROJECT I														
	WEEKS													
ACTIVITIES	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**
Project Title • Brainstorming and proposing on possible project title with supervisor														
Data Gathering and information • Gather data and information from relevant and similar past research papers														
Extended Proposal • Submission of extended proposal to supervisor and course coordinator														
Proposal Defense • Presentation with internal examiner														
Project Work Continuation • Continuation of project work.														
Submission of Interim Report and draft • Compilation and preparation of report for this semester														

Gantt chart - FYP 2

Joeal Lim Guan Chin Matrix ID: 15115 Petroleum Engineering, Final Year Final Semester FINAL YEAR PROJECT 2														
	WEEKS													
ACTIVITIES	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**
Simulation Activities • Performing simulation using available simulator to obtain results of studies														
Progress Report • Submission of Progress Report														
Discussion and Results Detailed analysis on the results obtained														
Pre-SEDEX and Poster Presentation • Presentation with external examiner														
Submission of final draft and dissertation • Finalizing the project paper with supervisor.														
Submission of Technical Paper and Finalized Project • Handing in hardbound project paper to supervisor														
Viva Presentation • Presentation of research to Internal and External Examiners														

3.5 Simulation Data

The simulation studies on the three (3) mentioned basins are performed by the available simulators namely; Schlumberger's ECLIPSE (main). The base case model are obtained from ECLIPSE folder and each of them are modified in accordance to the parameters being studied; percentage of gas injection. Other reasonable assumptions are also being made in the model to ease the process of achieving the objectives.

The ECBM in E300 provided by Law et. al is the 5-spot Pattern which also cited by Tunio and Ismail in the studies of "Effect of Coal Rank and Porosity on the Optimization of ECBM Recovery"

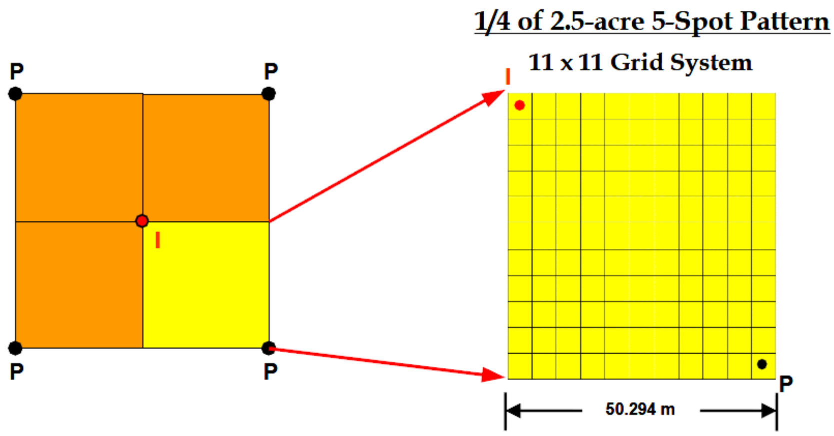

Figure 3.3 Schematic Diagram of rectangular grid system that are used for the ECBM of CO2 injection (Tunio & Ismail, 2014) (Law, Meer, & Gunter, 2002)

By using the same 5-spot pattern (4 injectors and 1 producer well system), Law et. al also provided comparison of how the production of methane gases will behave with different type of commercial simulators. The comparison is done by comparing the primary production and the CO_2-ECBM as a function of time when simulated with different type of simulators (Figure 3.4). In general, due to presence of initial gas saturation, the methane gas production will experience a negative decline during the primary production that are caused due to the dewatering process. (Law, Meer, & Gunter, 2002).

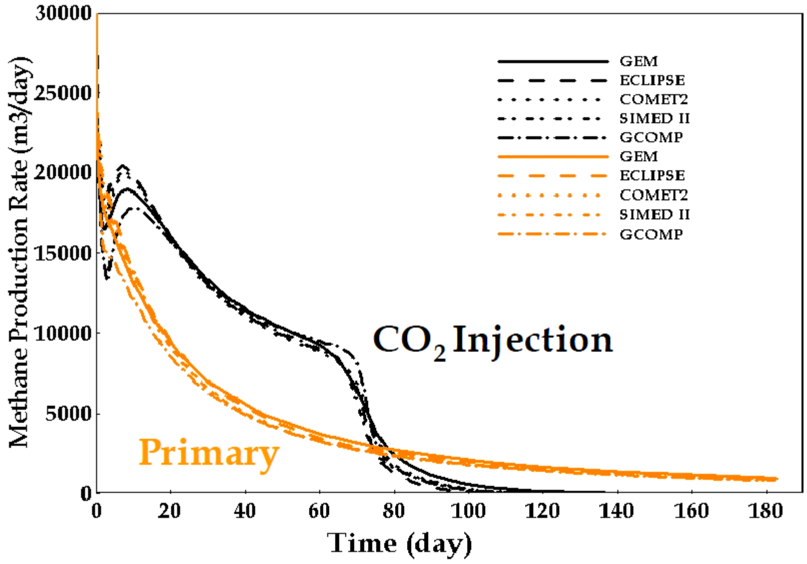

Figure 3.4 Comparison of methane gas production; primary CBM and CO2-ECBM Recovery with different simulators (Law, Meer, & Gunter, 2002)

For this research project, the three basins; 2 commercials- San Juan Basin and Powder River Basin and 1 non-commercial- Balingian Coalfield is being simulated. The properties for each of them are tabulated below:

Table 3.2 Modified data from the three case studies ((Tunio & Ismail, 2014) (Seidle, 2011) (Tunio, Chow, Irawan, & Kong, 2011) (Wang, Massarotto, & Rudolph, 2008) (Puri & Yee, 1990))

Parameters	**Basins and Coalfield**		
	San Juan Basin	**Powder River Basin**	**Balingian Coalfield**
Coal Rank	Sub-bituminous	Sub-bituminous C	Lignite
Coal Density (kg/m^3)	1430	1350	1335
Coal Depth (m)	1253.6	169.8	4.6
Permeability (mD)	3.65	10	2.235
Porosity	0.001	0.001	0.0275
Gas Saturation (S_g)	0.408	0.408	0.16
Initial Reservoir Temperature (◦C)	45	18.3	30
Initial Reservoir Pressure (bar)	76.5	34.5	19.7
Methane Gas Isotherm			
Pressure P_L (bar) **Volume V_L (sm^3/kg)**	46.885 0.01180736	61.09 0.00931	84.09 0.0116933813
Carbon Dioxide Gas Isotherm			
Pressure P_L (bar) **Volume V_L (sm^3/kg)**	19.030 0.0240808	38.28 0.03527	37.78 0.038081056
Nitrogen gas Isotherm			
Pressure P_L (bar) **Volume V_L (sm^3/kg)**	272.41 0.011652	77.22 0.00305	114.340917 0.0175110429

CHAPTER 4 RESULTS AND DISCUSSIONS

4.1 Simulation Procedures

As planned, the simulation studies are conducted by using the available commercial simulator which is Schlumberger's Eclipse E300 for its use-friendly functionality on ECBM simulation. The simulation results for the three (3) basins are analysed. The injection of different composition of gases will be referred as below:

- Case 1: 100% CO_2
- Case 2: 100% N_2
- Case 3: 25% CO_2 and 75% N_2
- Case 4: 75% CO_2 and 25% N_2
- Case 5: 50% CO_2 and 50% N_2

The discussion part will refer different composition of injected gas by Case 1, 2, 3, 4 and 5.

4.2 Simulation Results: San Juan Basin

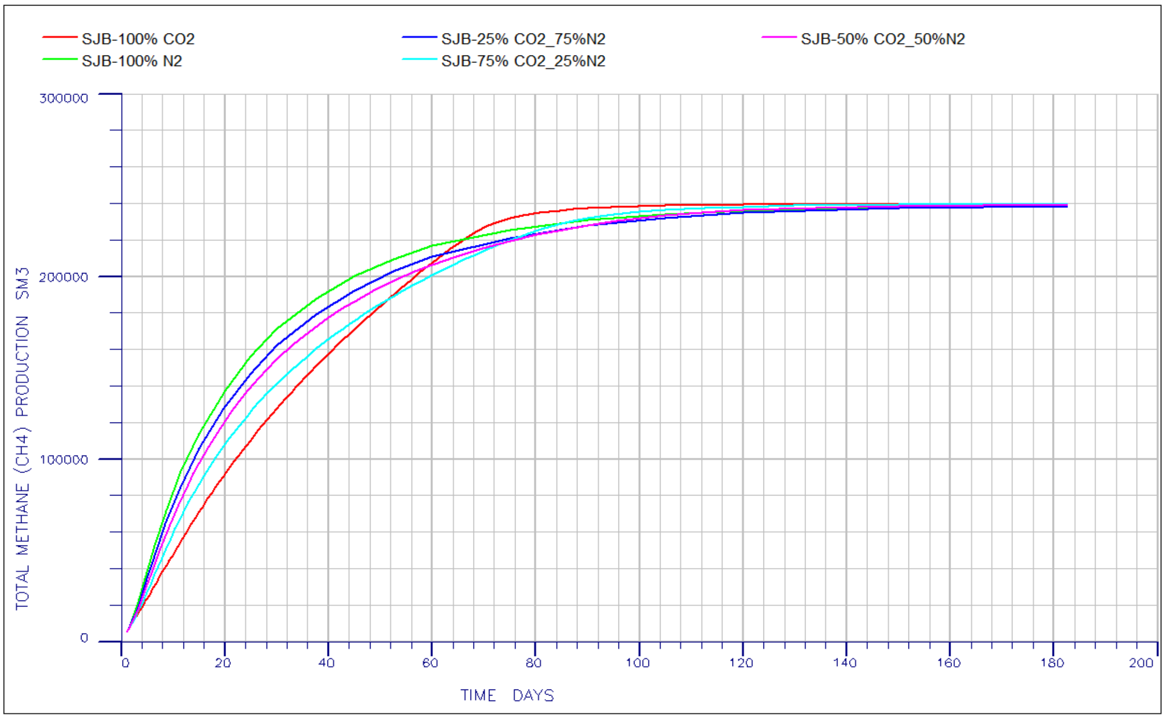

Figure 4.1 Total methane (CH_4) production of San Juan Basin with five different cases of simulations

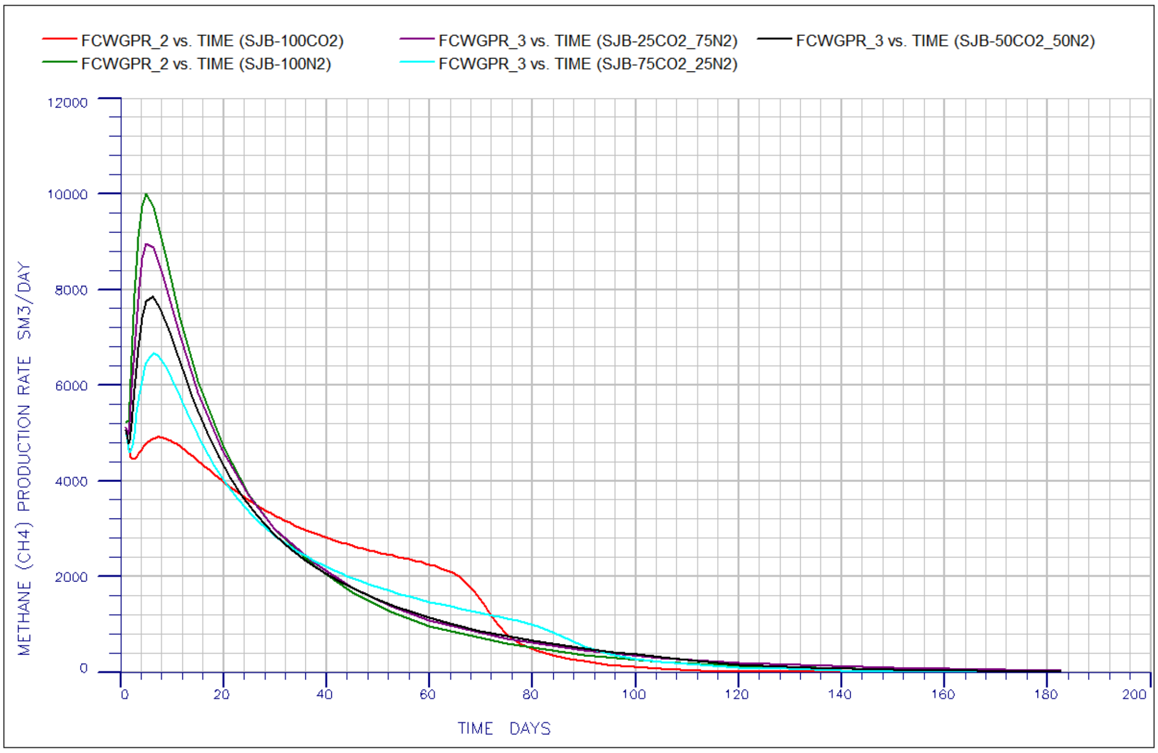

Figure 4.2 Methane (CH_4) production rate of San Juan Basin with five different cases of simulations

4.3 Simulation Results: Powder River Basin

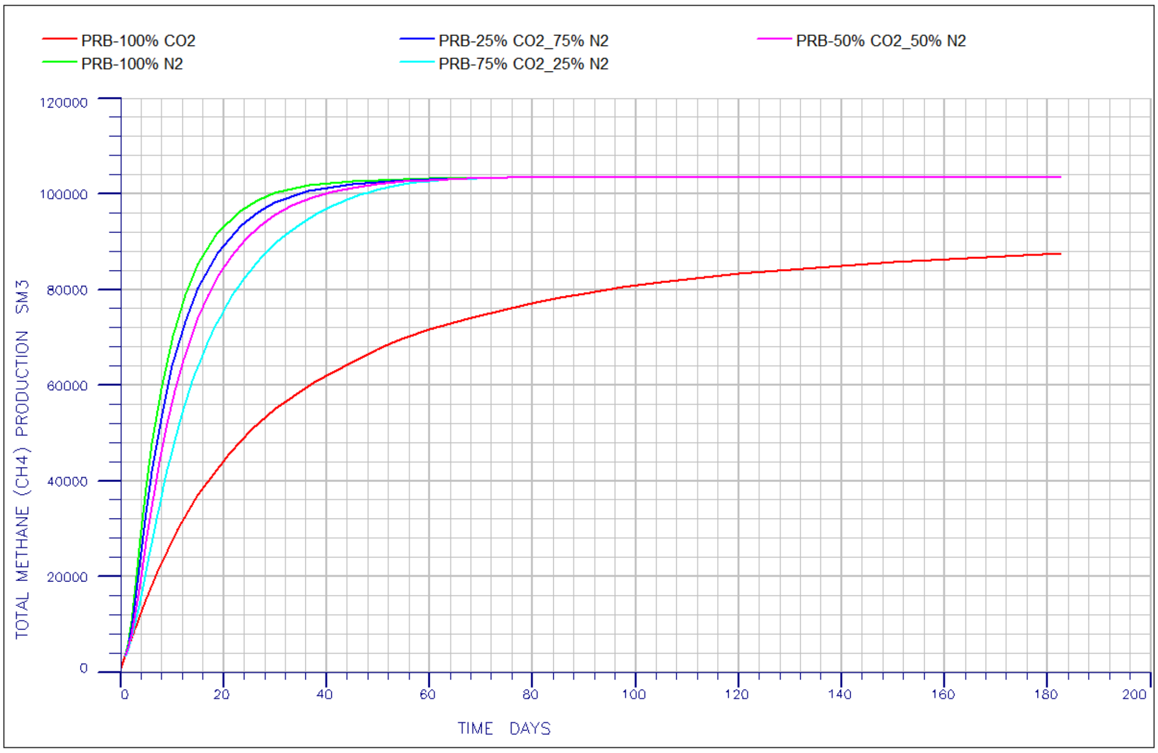

Figure 4.3 Total methane (CH_4) production of Powder River Basin with five different cases of simulations

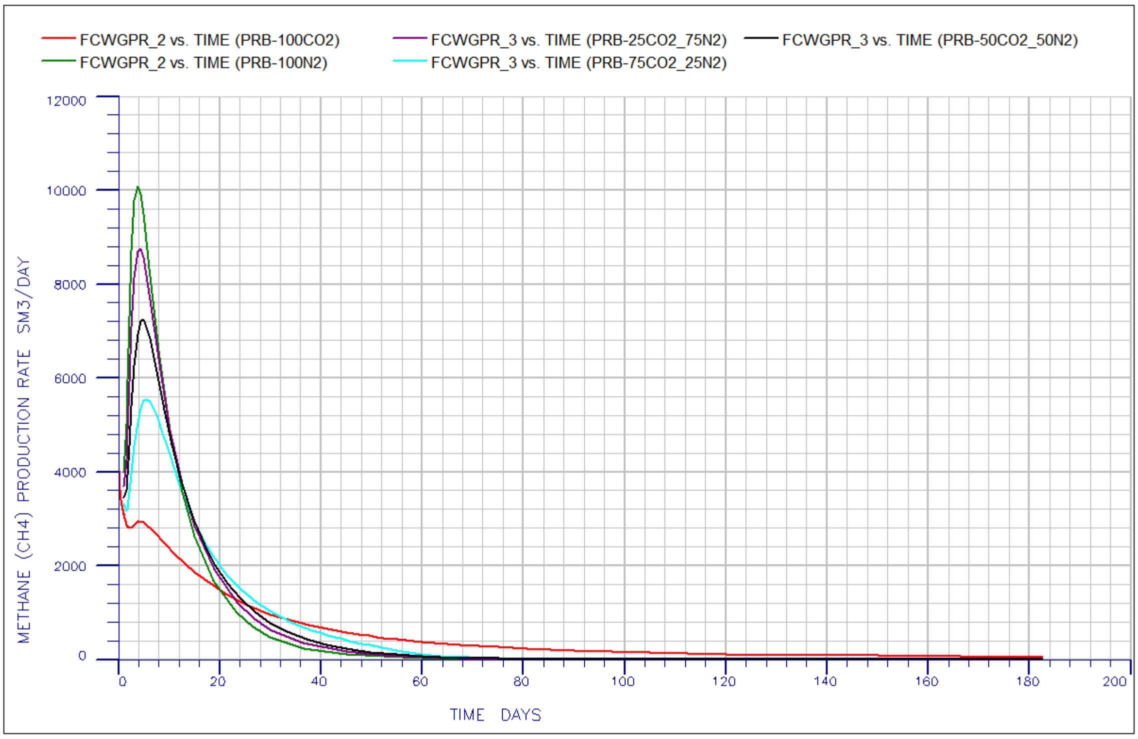

Figure 4.4 Methane (CH_4) production rate of Powder River Basin with five different cases of simulations

4.4 Simulation Results: Balingian Coalfield

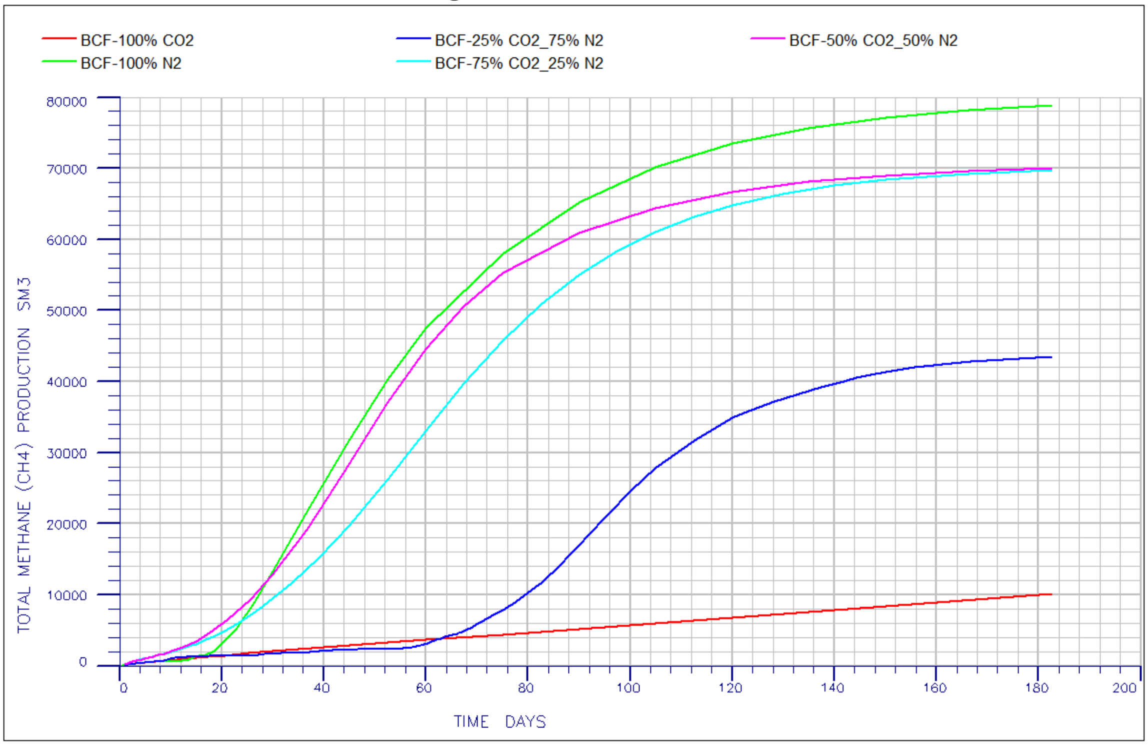

Figure 4.5 Total methane (CH_4) production of Balingian Coalfield with five different cases of simulations

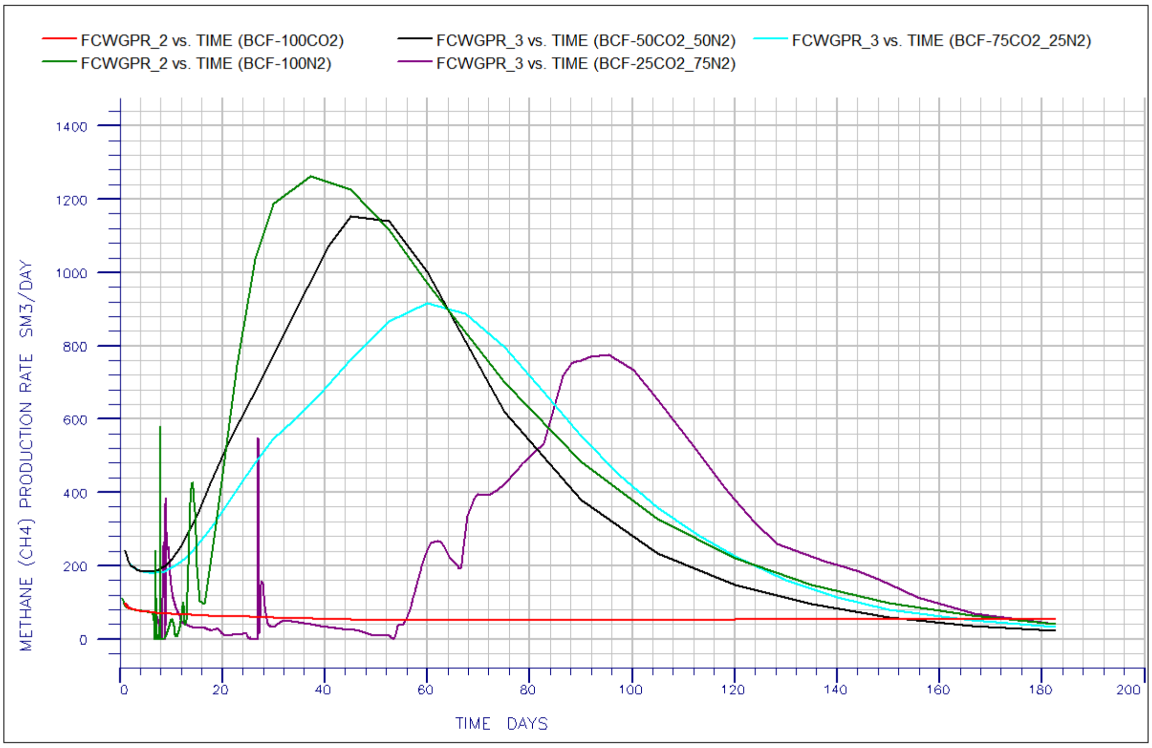

Figure 4.6 Methane (CH_4) production rate of Balingian Coalfield with five different cases of simulations

4.5 Comparison of Total Methane (CH_4) Production between Basins and Cases

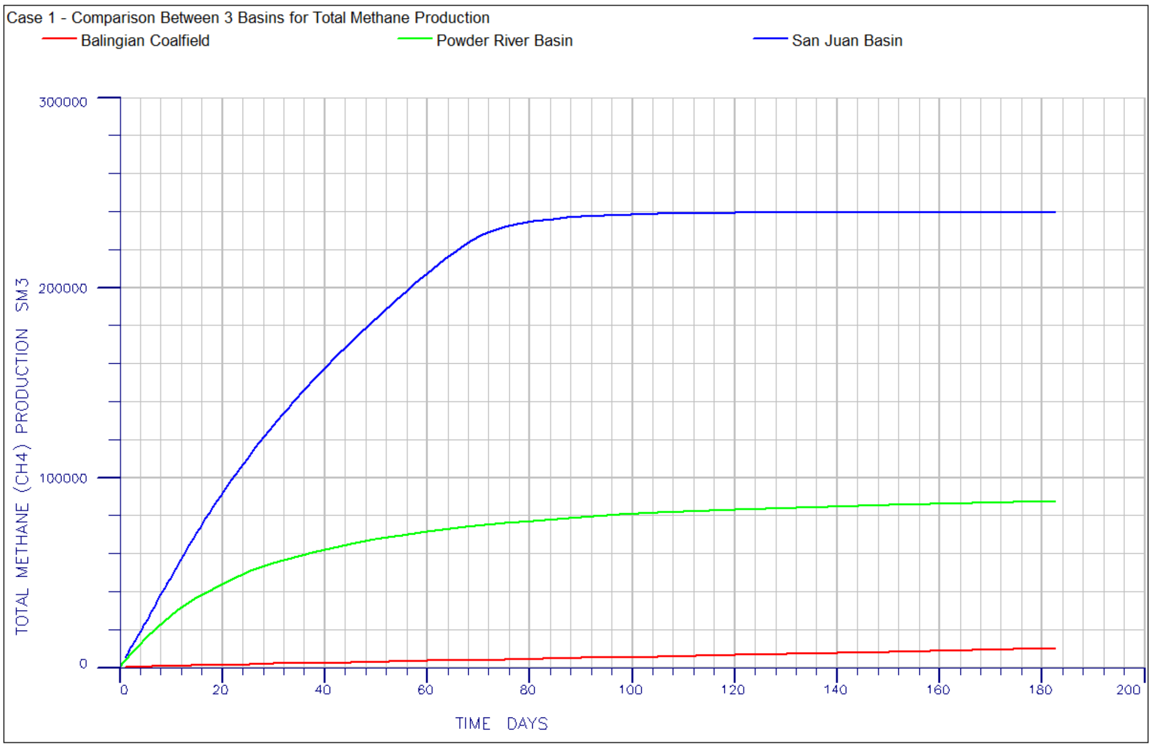

Figure 4.7 Case 1 - Comparison between San Juan Basin, Powder River Basin and Balingian Coalfield

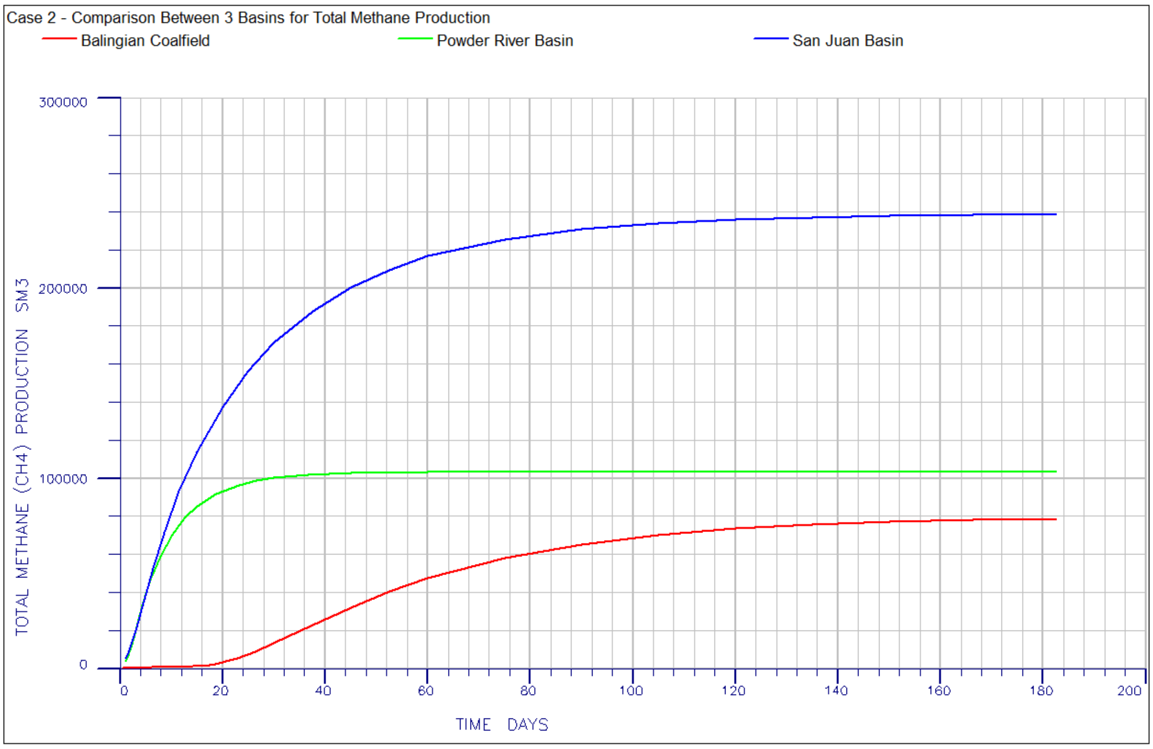

Figure 4.8 Case 2 - Comparison between San Juan Basin, Powder River Basin and Balingian Coalfield

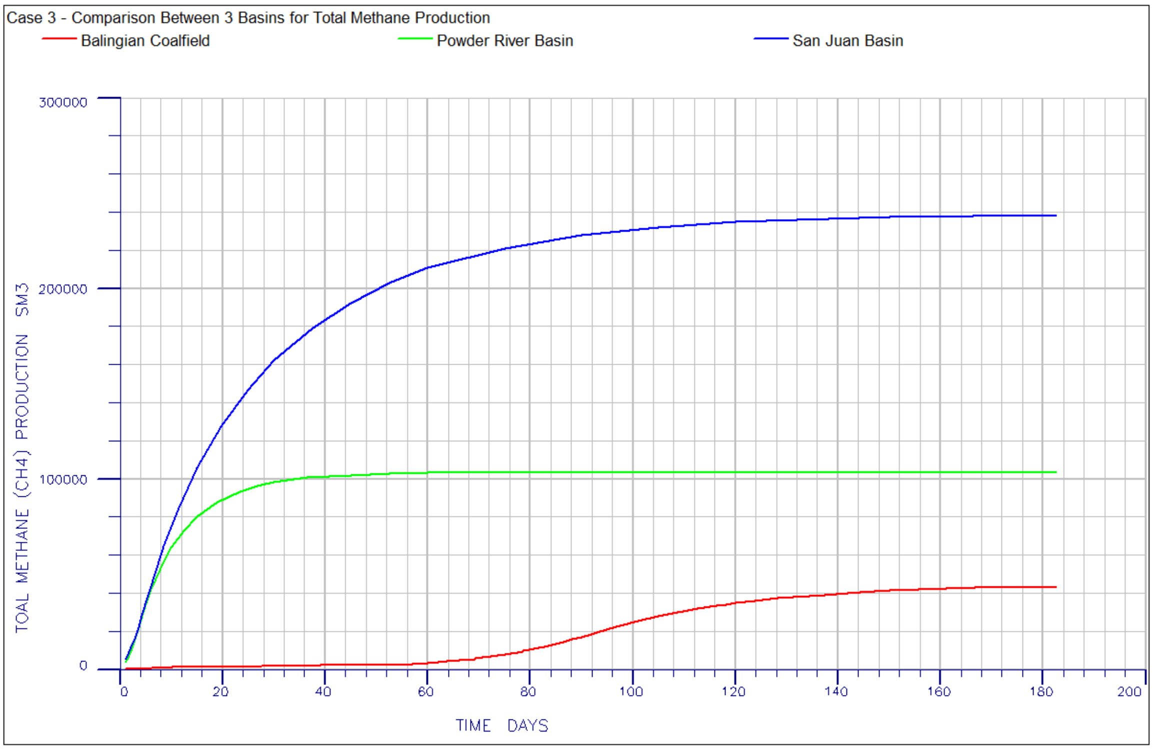

Figure 4.9 Case 3 - Comparison between San Juan Basin, Powder River Basin and Balingian Coalfield

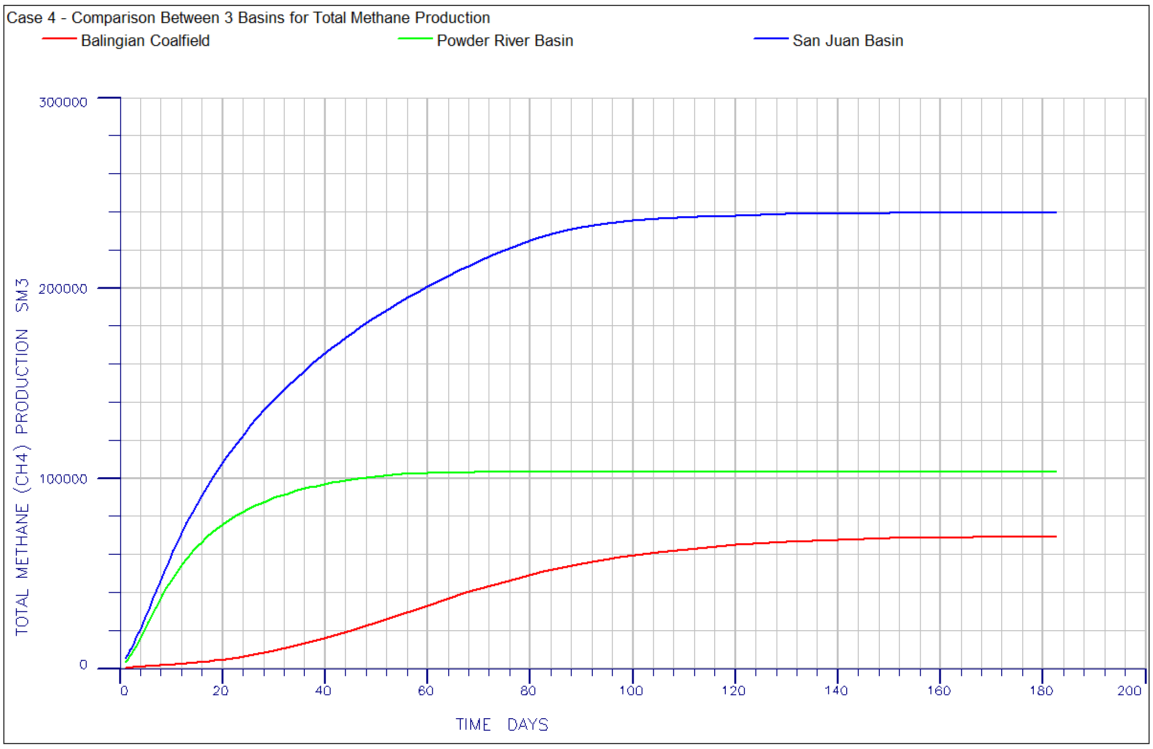

Figure 4.10 Case 4 - Comparison between San Juan Basin, Powder River Basin and Balingian Coalfield

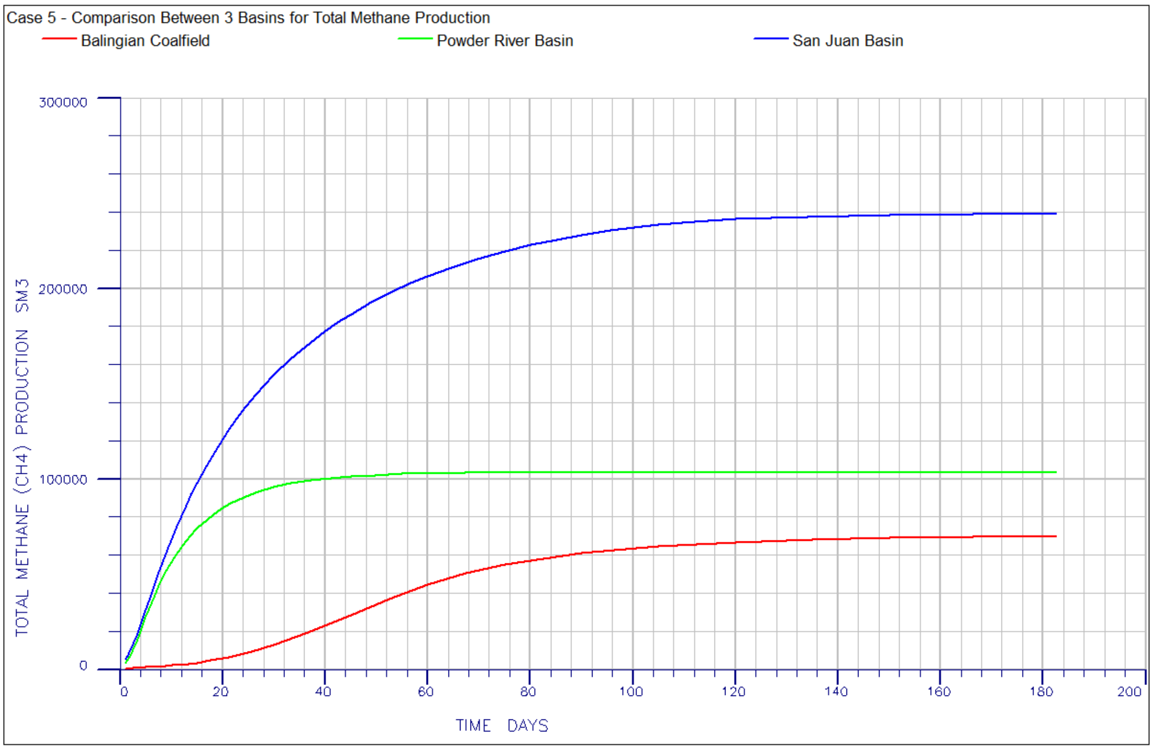

Figure 4.11 Case 5 - Comparison between San Juan Basin, Powder River Basin and Balingian Coalfield

4.6 Total Methane (CH_4) Production and Rates Analysis

(A) San Juan Basin

Figure 4.1 shows the total methane production for the San Juan Basin with comparison between the 5 different simulation cases. It can be observed that case 2 with the same period of time produces higher amount of recovered methane gas from the coal followed by case 3, 5, 4 and 1. In addition, it can be also observed that presence of nitrogen gas in the ECBM recovery helped to increase the total production of methane gas (CH_4). By increasing the amount of nitrogen gas in the injection composition, the higher the amount of total methane production as proven by case 2. The justification for how nitrogen gas and its amount in the injector assist in ECBM recovery will be further discussed and analysed.

Meanwhile, figure 4.2 shows the methane production rates for the same basin. It can be observed that all the cases that have presence of carbon dioxide gas in the injection will first yield a negative decline before slowly increase during the initial stage because the volume loss of carbon dioxide during carbon dioxide injection is more compared to the rate of methane gas recovered from the coal seam. Therefore it needed some time for the amount of injected carbon dioxide to be enough before slowly displacing the methane off the coal seam up to the surface (Wei, Wang, Massarotto, Rudolph, & Golding, 2014).

From the same figure 4.2, it can be observed that simulation case 2 has the highest amount of methane (CH_4) production rate then followed by Case 3, 5, 4 and 1. Comparing the two figures, the trend shows that when nitrogen gas amount is high in the composition of injected gas, it will yield higher amount of total methane production and also at faster production rates with respect to time when compared to lower amount of nitrogen gas in the injection.

(B) Powder River Basin

Figure 4.3 shows the results of 5 different cases of simulation studies on Powder River Basin. The simulation results have roughly the same trend when compared to that of San Juan Basin with difference in the total methane (CH_4) production. Total methane production from Powder River is halved of that from San Juan with total methane production of nearly 100,000sm^3 for case 2, 3, 4, 5 and 85,000sm^3 for case 1. One of the known reason for the lower production of methane for Powder River basin is due to its lower coal rank when compared to San Juan Basin which has a higher coal rank; sub-bituminous than to sub-bituminous C of Powder River (Tunio & Ismail, 2014).

In figure 4.4, small negative decline can also be observed for all the cases which have presence of carbon dioxide in it except for case 2 where the simulation involves only pure nitrogen gases. Case 2 also yield the highest rates under the short period of time explaining that after 40 days of production, its rates declining very fast due to high production already during the initial stage as shown in figure 4.3. Injection of pure carbon dioxide also fares the lowest in terms of production rate with only 3100sm^3/day when compared to pure nitrogen injection with production rates of nearly 10,000sm^3/day.

(C) Balingian Coalfield

Simulation results for Balingian coalfield is displayed in figure 4.5 and 4.6. According to the trend observed from figure 4.5, with pure nitrogen gas injection, the total production of methane gas can go as high as 80,000sm^3. This can serve as a good news for Malaysia to further develop this coalfield which might end up as the first CBM producer in the country. However, injection of pure carbon dioxide only will produce a maximum of roughly 10,000sm^3 after 180 days of production causing the production to be uneconomical and not feasible as the cost of production may be more than the profits gained.

From figure 4.6, it can be observed that the production rates of methane gas from Balingian coalfield is very small when comparing with the major CBM producers like San Juan Basin and Powder River Basin. Even with pure injection of nitrogen gas, its production rates can only rise up to approximately 1,250sm^3/day after 40 days of productions. These rates are not enough for Balingian to be economically to produce.

Other reason that can explain low methane production and inconsistent rates from Balingian coalfield may due to lack of accurate data used for the simulation process. This is because of lack of information and research on this coalfield. In addition, the coal rank of this coalfield can also attribute to the low productivity. Balingian coalfield has coal rank ranging from lignite to sub-bituminous which is relatively young coal explaining the poor storage capacity of carbon dioxide gas.

More research and studies are required to perform on this coalfield to conform its suitability to become an economical producer of CBM in Malaysia.

(D) Comparison Between Basins With Respect To Cases

Figures 4.7 to 4.11 shows the comparison of total methane (CH_4) production between each basins with respect to different cases. From all the five (5) cases, all of them have the same trend where San Juan Basin has the highest methane production followed by Powder River Basin and Balingian Coalfield. The only difference in each cases is the time taken for the production to reaches its peak.

It is observed that among the 5 cases, case 2 takes the shortest amount of time for the total methane production to reach its peak of 60 days, 28 days, and 80 days for San Juan, Powder River and Balingian respectively whereas, case 1 takes the longest time for the total methane production to reach its peak of 75 days, 80 days and 100 days respectively.

For other cases, the time required for the total methane production to reach its peak is increased with the increased amount of nitrogen gas in the injection.

4.7 Analysis of Observed Results

Based from simulation results obtained and shown above, it can be seen that the injection of pure (100%) nitrogen gas into the coal seam will produce better total production and rates of methane (CH_4) regardless of basins or coalfield. Although carbon dioxide gas has higher affinity (sorption capacity) to coal compared to nitrogen and methane, the injection of pure (100%) carbon dioxide generates the least recovered CH_4 as proven in figure 4.1, 4.3 and 4.5.

The reason is because even though it is easier for carbon dioxide to displace methane gas off the coal seam, it will cause swelling in the coal due to its large molecular weight and size. This swelling will then cause the already low permeability of coal to be even smaller (Zhou, Hussain, & Cinar, 2013). As a result, the low permeability of the coal can decrease the rate of injection that in the end causes the low production of methane.

On the other hand, the injection of nitrogen gas will not cause the swelling of coal due to its lesser sorption capacity. Because of nitrogen's low affinity to coal, it has the better sweeping efficiency when compared to carbon dioxide (Durucan & Shi, 2008). Instead of mostly being adsorbed to the coal seam, nitrogen gas helps in the N_2-ECBM recovery by lowering the partial pressure of methane in the cleat. The partial pressure is decreased when a portion of it are swept away by the injected nitrogen gas. "As a result, it will creates a compositional disequilibrium between the gaseous and adsorbed phases. In the end, the instability phase will allow methane gas to desorb from the coal seam and escape" (Reeves & Oudinot, 2004).

CHAPTER 5 CONCLUSIONS

Based on the simulation results, the total methane (CH_4) production and production rates from the investigated 2 basins and 1 coalfield are observed. Pure injection of nitrogen gas (N_2) produce the best results in terms of total methane (CH_4) gas production and production rates whereas pure injection of carbon dioxide (CO_2) fares the lowest.

In terms of different composition of injection gases (CO_2 and N_2), higher amount of nitrogen gas will obtained greater amount of total methane production. This is because a large amount of nitrogen in the coal seam will facilitate in lowering the partial pressure that helps the methane gas to escape to the surface or producer(s) well if available.

After comparing, pure nitrogen injection is concluded to be the best seletion for ECBM recovery. Aside from its excellent sweeping efficiency and partial pressure reduction of methane gas that leads to higher total methane production, its abundance and readily available (78% of composition of air) also do makes it even more viable option in the ECBM recovery.

As a conclusion, the 2 objectives to study the pure injection gases and their mixtures are achieved.

RECOMMENDATIONS

Due to time limitations and financial constraints, the research cannot be expanded to include more basins and more different parameters to be investigated on.

It is recommended that future work of expansion can be done to this research so that the recovery of ECBM can be further improved on and it's potential to produce higher amount gas maximised.

Few of the recommendations for future work or improvement would be:

- Performing both stimulation and simulation activities on the investigated basins instead of only one
- Comparing the results with different simulators to ensure highest accuracy of results possible
- Expand the type of injected gas CO_2 and N_2 to other noble gases like helium, neon, argon, krypton and then make a comparison studies between them

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