Thermally Enhanced Gas Recovery and Infill Well Placement Optimization in Coalbed Methane Reservoirs

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A thesis submitted for the degree of

Doctor of Philosophy (Ph.D.)

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Table of Contents

Abstract

The aim of this thesis is to investigate innovate approaches that can help to improve methane recovery and production rate from coalbed methane (CBM) reservoirs. The results of two following subjects are presented and discussed. First, *thermally enhanced gas recovery* from gassy coalbeds is introduced. Second, an integrated reservoir simulation-optimization framework is developed and employed to optimize infill well locations across coalbed reservoirs.

When coalbed methane and geothermal activities coexist in the same field, coalbeds can be thermally treated prior to the gas production using available underground geothermal resources. Feasibility of this method is investigated both using methane sorption tests on Australian coal samples at different temperatures and also reservoir simulation.

The impact of temperature elevation on methane sorption and diffusion in coal is investigated by running sorption experiments on two the Australian coal samples using a manometric adsorption apparatus. Experiments are performed to indicate that how the difference between original reservoir pressure and critical desorption pressure is decreased at elevated reservoir temperatures. Lower pressure gradient is required to extract methane from coalbed when it is thermally treated prior to gas production.

Following the experimental study, the feasibility of thermally enhanced gas production from coalbeds is studied by coupling of coalbed methane and thermal simulators. The coalbed methane simulator of Computer Group Modelling (CMG) and the thermal simulator of CMG known as STARS are loosely coupled to study the effect of temperature elevation on total gas and water production. Both gas rate and ultimate gas recovery from the reservoir are increased by thermal operation.

In the second part of this thesis, an integrated reservoir simulation-optimization framework is developed to intelligently obtain locations of new infill wells in a way to maximize profitability of the infill plan. This framework consists of a reservoir flow simulator (Eclipse E100), an optimization method (genetic algorithm), and an economic objective function. The objective function in this framework is to maximize discounted net cash flow of infill project.

The importance of optimization is magnified when cost of water treatment is increased. When optimization approach is compared with standard five spot pattern well arrangements, the impact of water treatment cost is observed. When cost of water treatment is high, there is a large difference between the profit of the infill project calculated using the optimization approach and the standard five spot pattern. Simulation results indicate that at higher cost of water treatment, infill wells are preferably located either on the front of the water depletion zone or close to existing wells. On the other hand, when water treatment cost is low, infill wells are located in virgin sections of the coalbed where both gas content and cleat water saturation are high.

Statement of Originality

This work contains no material which has been accepted for the award of any other degree or diploma in any university or other tertiary institution to Alireza Salmachi and, to the best of my knowledge and belief, contains no material previously published or written by another person, except where due reference has been made in the text.

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Alireza Salmachi   Date

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List of Publications

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II. Salmachi, A. and M. Haghighi (2012). "Temperature Effect on Methane Sorption and Diffusion in Coal: Application for Thermal Recovery from Coal Seam Gas Reservoirs." Journal of APPEA **52**: 291-300.

III. Salmachi, A. and M. Haghighi (2012). "Feasibility Study of Thermally Enhanced Gas Recovery of Coal Seam Gas Reservoirs Using Geothermal Resources."Energy & Fuels **26**(8): 5048-5059.

IV. Salmachi, A., M. Sayyafzadeh, and M. Haghighi (2012). "Infill well placement optimization in coal bed methane reservoirs using genetic algorithm." Fuel **111**(0)**:** 248-258.

V. Salmachi, A., M. Sayyafzadeh, and M. Haghighi (2013). "Optimization and Economical Evaluation of Infill Drilling in Coal Seam Gas Reservoirs Using a Multi Objective Genetic Algorithm." Journal of APPEA 53: 381-390.

Statement of Authors' Contribution

This thesis is submitted for the partial fulfilment of the requirement for the degree of Doctor of Philosophy (PhD) in petroleum engineering at the University of Adelaide, Adelaide, Australia. The thesis comprises of both publications and written narratives in accordance with 'Academic Program Rules and Specifications 2012'. All the journal papers published and/or submitted are indexed in the 'ERA 2012 Journal List' database. This research was conducted in Australian School of Petroleum, the University of Adelaide, from February 2010 until January 2013. The sorption experiments for coal samples were performed in the laboratory of the school of chemical engineering, the University of Queensland under the supervision of **Doctor Greg Birkett** in June 2011. The following chapters and all the 5 papers attached to the thesis are the outcomes of this research. All the papers in this thesis are co-authored and detailed statements of their contributions are endorsed by the co-authors.

STATEMENT OF AUTHORSHIP

Infill well placement optimization in coal bed methane reservoirs using genetic algorithm

Fuel, 2013, volume 111(0), pages: 248-258

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Chapter 1: Introduction

1.1 Coalbed methane reservoirs

Coal as a solid fuel was an old energy resource contributing to a large proportion of energy production in the past few centuries. The search for coal mines in deeper gassy coal beds introduced methane as a dangerous hazard to the mining industry. Methane capturing from gassy coal beds and ventilation systems have a long history in coal mines to produce a safe environment for mine workers. It was just in 1974 that coal bed methane came to the market for sale for the first time (McLennan, 1995). Coalbed methane reservoir exploitation converted the coal methane as the centuries old hazardous gas into a clean resource of energy. They are classified as unconventional gas resources similar to tight gas and shale gas reservoirs and possess unique reservoir properties different from the conventional gas reservoirs. Both the gas storage and the gas transport in coal beds are different from conventional gas reservoirs. Gas storage mechanism in coal is typically based on sorption which is a very efficient way of storage compared to the gas compression in pores in conventional gas reservoirs. A good quality coal bed can store several times more gas compared to a sandstone reservoir at the same pressure and temperature (Seidle, 2011).

Coal beds are naturally fractured reservoirs with a well developed network of fractures normally called cleats. Cleats are responsible for the flow capacity of the reservoir conducting the reservoir fluid. Coal permeability is mainly due to the cleat network. Coal matrix is very complex in terms of the pore structure. Pore sizes can change from nano-scales to micro-scales giving the coal a complex network of pores. The fact that coal has a large surface area makes it an excellent candidate for gas sorption.

Gas mainly exists in the form of the adsorbed phase in the coal matrix. In the adsorbed phase, gas molecules adhere to the available surface area of the coal. The degree of attachment of methane molecules to the surface of coal is in the range of the condensation bonds and can be easily broken by either pressure depletion or temperature elevation.

When coalbed is penetrated using a well, a pressure gradient is imposed on the coalbed. The fluid residing inside the cleats moves towards the wellbore in the direction of the pressure gradient. In wet coals cleats are filled with water and water production is expected at the early life of the well. Some coals are dry and high gas rates are experienced when the coal bed is penetrated. Fluid flow in coalbed occurs in two stages at different scales. In the first stage, gas desorbs from surface of the coal and a concentration gradient is created in the coal matrix. The concentration gradient results in gas diffusion in the coal according to the second Fick's law. Gas diffuses in very narrow pores of the coal matrix typically in nano-scale sizes. Gas diffusion in coal pores is believed to be a combination of molecular diffusion, Knudsen diffusion, and surface diffusion. In the second stage, when gas saturation in cleats reaches to a critical saturation, gas starts to flow through cleats and is normally described by the Darcy law.

Coal is unique being both source rock and reservoir rock at the same time. In conventional gas reservoirs, pressure depletion results in gas expansion in pores whereas in coal beds pressure depletion results in gas desorption from the sorption sites in the coal matrix followed by gas diffusion in the pores. Water production at the early life of the reservoir is known as dewatering. Dewatering, at the early life of the reservoir, makes coal beds different from normal sandstone gas reservoirs. Gas rate is gradually built up and experiences a plateau followed by a decrease in rates afterward. Normally a peak gas rate is experienced during gas production from a well in wet coal reservoirs. Negative decline is the term used for the increasing gas rates up to the peak gas production which is different from the conventional gas reservoir (Seidle, 2011).

1.2 Problem statement

Low gas rates, high cost of water treatment and disposal, low reservoir pressure, and relatively low gas price make coal bed methane activities borderline economic efficient. The gas rates in CBM wells are usually lower than conventional gas reservoirs and they mostly require stimulation such as hydraulic fracturing technique to facilitate production.

Produced water requires treatment before either disposal or reusing. The water treatment increases operational cost associated with coal bed methane production. The cost of the water treatment depends on the water quality and the produced volume. Depending on the water quality, water treatment and disposal method, and the environmental regulations in the area, the cost of water treatment and disposal can vary from 0.04 $/STB up to 2 $/STB (Ham and Kantzas, 2008). On average, CBM wells in Queensland, Australia, produce 20000 litres of water per day per well and this number can increase up to hundreds of thousands of litres per well per day (CSIRO, 2011a). The treated water can be disposed in evaporation pits at surface or reinjected into the underground aquifers where the injected water and the original water in aquifer are chemically compatible. Also, the water can be used for water supply and irrigation purposes when it is carefully treated.

Generally coalbeds are shallow (<1000 m) and possess low pressure. It is required to reduce the reservoir pressure down to a critical desorption pressure to initiate gas production. Down-hole pumps are normally installed to reduce the wellbore pressure and transmit gas and water to the surface.

Gas price in the market and local regulations are non technical challenges affecting the economical development of coalbed methane projects. Gas price in the market is the dominant factor deciding on the economic success or failure of a CBM project. In the United States, gas price has declined from 10 $/Mscf in 2008 to around 2 $/Mscf in 2012 and this dramatically slowed down CBM activities (U.S.EnergyInformationAdministration, 2013). The CBM industry in Australia faced with a jump in cost of water treatment and disposal when environmental regulation banned water disposal in evaporation pits. Water purification at surface facilities and water re- injection into underground formations are more expensive practices compared to the water disposal at pits. Tightened environmental regulations have cut down CBM projects benefits and urge the need for advanced technologies for optimal production from CBM projects.

Currently carbon dioxide and nitrogen injection are introduced as the two enhanced techniques in coal bed methane reservoirs to improve gas recovery. The principle idea in these techniques involves the use of carbon dioxide or nitrogen to facilitate the gas desorption from the coal matrix. The presence of nitrogen in cleats reduces the methane partial pressure in cleats and subsequently more methane is desorbed from the matrix. Carbon dioxide substitutes the methane in the adsorption sites due to the higher adsorption affinity. Carbon dioxide adsorption capacity on coal was reported to be two times higher than the methane (Faiz et al., 2007). Carbon dioxide geological sequestration in underground formations along with higher gas recovery from coal reservoirs making carbon dioxide injection in underground coals an interesting method. Long lasting storage of carbon dioxide in underground coals and the cost of transportation and injection are still challenging issues in this area.

Infill drilling can also be considered to increase the field gas rate and shorten the production time of the reserve. The time value of the money is increased when the gas is produced at higher rates and it may justify the drilling of additional wells in coal reservoirs. Infill drilling should be able to pay back capital expenditures due to cost of new wells in the reservoir as well as the need for additional surface facilities and pipelines. A cost effective infill project entails drilling new wells in sweet spots. Smart well placement across the reservoir can maximize profitability of the infill project by maximizing the gas rate while water production is minimized.

Geothermal resources are abundant and pervasive across the globe. Geothermal resources are generally classified into two groups: hot dry rocks (HDR) and hydrothermal resources. The hydrothermal resources are abundant and the average water temperature is usually not sufficient for electricity generation at the surface but they can be widely used for direct heating purposes. Currently available geothermal resources are used for both industrial and heating purposes such as spa heating, crop drying, distillation, and de-icing. Unfortunately a large number of the geothermal resources are left undeveloped due to either locating in remote areas or low water temperature (Harries et al., 2006). The existence of both a geothermal resource and a coal bed in the same field is a valuable opportunity for energy extraction. It is probable that with current technology and market gas price CBM and geothermal resources do not have sufficient properties for economical energy production on their own and are left undeveloped.

1.3 Objectives

The main objective of this thesis is to investigate innovate approaches that can help to improve methane recovery and production gas rate from coalbed methane reservoirs. First, *Thermally Enhanced Gas Recovery* from coalbed methane reservoirs is proposed as an innovative approach that has the potential to enhance gas recovery. In this approach, we take advantage of underground geothermal resources coexisting with coalbeds to thermally treat the coal prior to gas production. Feasibility of this method is investigated using experiments on coal samples and also reservoir simulation.

In the second part of the thesis, an integrated reservoir simulation-optimization framework is developed to obtain both optimal locations of new infill wells and also the optimum number of infill wells for an infill project. This framework consists of three components, the reservoir flow simulator (ECLIPSE E100), the optimizer (Genetic Algorithm), and the economic objective function working in an automatic framework.

The scopes of the following chapters are listed below:

1. A comprehensive literature review of petro-physical and reservoir characteristics of coal bed methane reservoirs.
2. Experimental determination of methane sorption and diffusion in coal samples at different temperatures.
3. Demonstration of thermally enhanced gas recovery technique using available underground geothermal resources.
4. Simulation of thermally enhanced gas recovery at the reservoir scale using loose coupling of coalbed and thermal simulators.
5. Development of an integrated reservoir simulation-optimization framework to obtain optimal infill well locations in a coalbed methane reservoir.

1.4 Thesis structure

This thesis has a combined conventional and publication format. Four journal papers and one conference paper are included in the thesis. All journal papers in this thesis have been published in peer reviewed journals and the conference paper has been presented and published in an international SPE conference. Table 1 summarizes all the publications included into this thesis. The thesis consists of three main chapters and these chapters contain written narrative and related publications. The arrangement of chapters is as follow:

Chapter three: Temperature Effect on Methane Sorption and Diffusion in Coal

Chapter four: Thermally Enhanced Gas Recovery from Coalbed Methane Reservoirs

Chapter five: Coalbed Methane and Water Production Optimization Using Genetic Algorithm

Table1.1: Publications list

No	Publisher/ Journal	Title	Status	Chapter
1	APPEA journal	Temperature Effect on Methane Sorption and Diffusion in Coal: Application for Thermal Recovery from Coal Seam Gas Reservoirs	Published 2012	Chapter 3
2	SPE conference IPTC 2011 Bangkok	Combined Energy Recovery from Coal Seam Gas Reservoirs and Geothermal Resources (Simulation Study)	Published 2011	Appendix 2
3	Energy&Fuels	Feasibility Study of Thermally Enhanced Gas Recovery of Coal Seam Gas Reservoirs Using Geothermal Resources	Published 2012	Chapter 4
4	Fuel	Infill well placement optimization in coal bed methane reservoirs using genetic algorithm	Published 2013	Chapter 5
5	APPEA journal	Optimization and Economical Evaluation of Infill Drilling in Coal Seam Gas Reservoirs Using Multi-Objective Genetic Algorithm	Published 2013	Chapter 5

1.5 Linkage between the publications and their contributions to this thesis

To improve both gas recovery and gas rate from coalbeds, *thermally enhanced coal gas recovery* is introduced as an innovative approach and feasibility of this method is investigated using thermal and reservoir simulators. Also, optimum economical production is attained through intelligent well placements across CBM reservoirs during infill programs.

Chapter 3 entitled "Temperature Effect on Methane Sorption and Diffusion in Coal" comprises of one journal paper which investigates the impact of temperature elevation on methane sorption and diffusion in coal matrix. In paper 1, methane adsorption isotherms on two Australian coal samples are measured at two experimental temperatures. It is found out that both critical desorption pressure and total gas recovery from coal are increased at elevated temperatures. Later, results of paper 1 are used to support the thermally enhanced gas recovery method in chapter 4.

Chapter 4 entitled "Thermally Enhanced Gas Recovery from Coal Bed Methane Reservoirs" introduces a thermal method in coalbeds to improve the gas recovery and gas rate from coal gas reservoirs. This chapter comprises of one journal paper (paper 3) and also written narratives. In chapter 4, thermal method and the assumptions made are described in details and geothermal resources are proposed as available sources of energy to heat the coal bed prior to the gas production. In addition, temperature dependent reservoir parameters including coal permeability, sorption isotherm, diffusion coefficient, and reservoir fluid viscosity are discussed. Paper 3 is a comprehensive study of the *thermally enhanced gas recovery* from CBM reservoirs simulating both heat flow propagation in coal bed during hot water injection phase and also heat loss to adjacent formations during the gas production phase. In this paper, total amount of water required to heat the coal bed, temperature distribution change in the reservoir, gas rate, and gas recovery are shown for an inverted five spot model.

Chapter 5 entitled "Coal Bed Methane and Water Production Optimization Using Genetic Algorithm" studies the benefits of infill well locations optimization across the reservoir using an integrated framework. The integrated reservoir simulation-optimization framework is developed to obtain optimal locations of new infill wells in coalbed during an infill plan. This chapter comprises of two papers and written narratives. The designed framework and its components are discussed in chapter 5. Paper 4 applies this framework to the case study introduced in paper 2 available in Appendix 2. In paper 4, both optimum locations and the optimum number of infill wells are obtained for the Tiffany unit coal in San Juan basin. Then, a sensitivity analysis is performed to study the impact of water treatment and disposal cost on well placements in the reservoir. New well locations across the reservoir are intelligently selected by the integrated framework to maximize infill plan revenue. Paper 5 addresses infill well locations optimization using the multi-objective genetic algorithm. In this paper an optimal Pareto front is calculated containing a set of best obtained and non-dominated solutions for infill wells distribution across the reservoir. Each point on the Pareto front corresponds to a distribution of infill wells. The Pareto front enables the operator to assess economics of infill program based on available solutions.

Chapter 2: Literature Review

2.1 Coal formation and structure

Coal is a sedimentary rock composed of organic and clastic materials mostly from plant debris. From petrological point of view, coal can be regarded as a sedimentary rock which was subjected to low grade metamorphism. The coal properties depend on the nature of the original organic materials accumulated in the coal formation environment and more importantly on the degree of the diagenesis (Ward, 1984).

Coal formation starts when microbial decomposition of plants is occurred in shallow water environments where significant amount of plants are deposited rapidly. Plants decomposition covering with sediments results in the formation of a moist, porous material called peat.

The development of the flora, the climate, the geographical locations, and the tectonics of the area are essential factors affecting the peat formation in shallow water swamps. High degree of vegetation and warm and humid weather create appropriate conditions for peat formation (Ward, 1984). When peats are deeply buried, they are compressed and dried. The texture and the composition of the peat are modified due to the diagenesis. The diagenesis or low grade metamorphism of the peat is occurred due to the burial and tectonic activities.

The coalification term has been introduced to describe the maturation process occurring through peat alteration to brown coals, sub bituminous and bituminous coals to anthracite and meta anthracite. The coalification process is initiated as a result of pressure, temperature and time. During the coalification process, significant amount of thermogenic methane is released. At this stage micropores and cleats are formed. Micropores accommodate a huge amount of produced methane while cleats conduct the gas flow inside the coal.

The degree of pressure and temperature increase during the geological formation of the coal can be recognized by the coal rank. It is a valuable indicator of coal properties and also the economics of coal gas production. When peat is subjected to minor structural changes during the coalification process, the coal possesses characteristics close to the original peat and it is classified as a low rank coal. When coal experiences significant alteration and its structure is different from the original peat, it is characterised as a high rank coal (Ward, 1984).

Coal rank defines thermal maturity of the coal and is classified into four groups based on their maturity: Lignite, Sub bituminous, bituminous, and anthracite. The ASTM classification of coal by rank is based on fixed carbon content, volatile matters and caloric value of the coal (McLennan, 1995). Table 2.1 shows the coal classification based on the ASTM standards. The four main groups of the coal ranks are divided into 13 subgroups. Generally black coal is referred to the coals standing in sub bituminous, bituminous and anthracite classification while the term brown coal is normally used for lignite. Most of successful CBM activities occur in high volatile to low volatile bituminous coals having a good degree of gas content, mechanical properties, and a well developed cleat network.

Table 2.1: Coal Rank by ASTM

Coal Rank by ASTM	Abbreviation
Anthracite	
Meta anthracite	Ma
Anthracite	An
Semi anthracite	Sa
Bituminous	
Low volatile bituminous coal	Lvb
Medium volatile bituminous coal	mvb
High volatile bituminous coal A	hvAb
High volatile bituminous coal B	hvBb
High volatile bituminous coal C	hvCb
Sub bituminous	
Sub bituminous coal A	sub A
Sub bituminous coal B	sub B
Sub bituminous coal C	sub C
Lignite	
Lignite A	lig A
Lignite B	lig B

2.2 Pore size distribution

Coal possesses a wide range of pores with pore sizes ranging from nanometres to micrometers. Wide variety of pores in coal is responsible for special coal properties like molecular sieving and matrix swelling /shrinkage (Levine, 1992, Rice, 1993).

Pore structure of coal is generally classified based on pore sizes into 4 groups: ultramicropores, micropores, mesopores, and macropores. Van Krevelen in 1993 classified the pores with the size less than 2 nanometres as micropores and those with the size larger than 50 nanometres as macropores. The intermediate pores, also known as mesopores, have a range of sizes between 2 to 50 nanometres (Van Krevelen, 1993). Based on surface area analysis of pores the average diameter of 20 Angstrom ($10^{-10}m$) reported for micropores (Krevelen, 1961). However micropore size analysis based on surface area measurements suffers from the fact that lowering the temperature down to 77 Kelvin can cause matrix contraction and some of accessible pores at normal temperature will not be longer available to hydrocarbons. The maximum diameter of micropores is estimated to be 40 Angstrom with pore throat size of 5 to 8 Angstrom in gas producing coals (Berkowitz, 1979).

When micropore sizes are comparable to molecular size of adsorbed molecules, they are categorized as ultramicropores (Radovic et al., 1997). The molecular diameter of methane is 4.1 Angstrom and cannot diffuse into pores with sizes smaller than 6.1 Angstrom (Heuchel et al., 1999). In coal matrix, ultramicropores and micropores are visualized as randomly distributed irregular holes (Radovic et al., 1997). Birds et al showed that more than 60% of pores in high volatile bituminous coals are less than 12 Angstroms in diameter (Bird et al., 1960). Considering the effective molecular diameter of methane, pore size is just a few times larger than the adsorbed molecules resulting in slow gas transfer in narrow pores. Micropore frequency substantially increases when coal rank increases from low volatile bituminous to anthracite (Rice, 1993). Ultramicropores and micropores constitute most of the surface area of the coal and play the main role in gas storage and sorption in coalbed methane reservoirs.

Pore size determines sorption mechanism in different pores. Gas sorption in extremely narrow pores (ultramicropores) is believed to be a combination of absorption and adsorption processes while gas sorption in micropores is dominated by pure adsorption (Milewska-Duda et al., 2000). Absorption is the penetration of adsorbed molecules into the coal texture while adsorption is a surface process occurs when gas or vapour molecules are trapped and adhered to surface of the pores.

Absorption is comparable to adsorption for carbon dioxide sorption on hard coals. Methane sorption is mostly dominated by adsorption due to low solubility of methane in coal. Higher sorption capacity of carbon dioxide on coals compared to methane is described by larger contribution of the absorption process (Milewska-Duda et al., 2000).

Hydrocarbons heavier than methane can block pore openings and restrict gas flow in micro pores system. Bae and Bhatia (2009) showed that barriers at pore throats make gas diffusion difficult. These barriers can be removed using heat treatment on coal matrix. Sources of these barriers are believed to be volatile matters in coal evaporating at higher temperatures (Bae et al., 2009).

Meso and macro pores are important in terms of gas flow in coal bed methane reservoirs and have minor contribution to gas adsorption and storage. The effectiveness of gas transport and the success in gas production from coalbeds largely depend on the ability of pores to feed fractures when coal bed is bleed off.

2.3 Coal porosity

Coal has as a dual porosity system. Cleat porosity defines the volume of the coal occupied with cleats. Cleat porosity is an indication of water storage inside the coal seam. Low cleat porosity is desired in wet coal seams because this might result in economical gas production from due to lower water production. The micro-porosity is referred to the volume of the micropores in the coal matrix which is of interest because more than 98% of the gas storage in coal beds is in the form of adsorbed phase (Gray, 1987). The contribution of cleat/macro porosity to gas storage in coal beds is negligible compared to the micro/meso porosity.

Coals have a wide range of porosity. Different authors reported different ranges for the coal porosity, 2.5 to 18 % (Anderson et al., 1956) and 4.1 to 23.2 % (Gan et al., 1972). Gan et al conducted an extensive research on the nature of the porosity in American coals using different porosity measurement instruments. Then they classified the nature of the porosity in different coal ranks. Mercury porosimetry was used to measure the macropore volume while the pore volume for pores smaller than 300 Angstroms calculated with nitrogen isotherms at 77 K. They claimed that in low rank coals (Lignite) the porosity is mainly due to the existence of macropores. In high volatile bituminous coals porosity is mainly due to volumes of micropores and mesopores while in high rank coals microporosity dominates (Gan et al., 1972).

2.4 Cleat system

Coalbeds are naturally fractured reservoirs with a well developed connecting cleat network. A well developed coal cleat system may consist of five types of fractures (Mavor, 1993):

1. Face cleats
2. Butt cleats
3. Tertiary cleats

4. Fourth order cleats
5. Joints

First set of fractures is called face cleat; they are major conducting fractures in coalbed. They are usually parallel, continuous and oriented orthogonal to coal bedding. Face cleats provide most of void space and also responsible for coal permeability in an underground coalbed. Second set of fractures is called butt cleat forming at an almost right angle to face cleats. They are shorter and discontinuous compared to face cleats and normally terminate along face cleat planes. The ratio of face cleat permeability to butt cleat permeability was reported to be 2.8 in the San Juan basin but the ratio can be a higher number in other basins (Mavor, 1992) .

Tertiary and fourth order cleats are formed after face and butt cleats formation and are extended between them. Joints are parallel with face cleats and they can improve vertical permeability of coalbed.

The cleat network in coalbed can be well identified by cleat density, cleat aperture and orientation. Cleat density is the number of cleats in the unit volume of the coal. Cleat spacing widely varies in coal and it depends on the rank. Spacing is often large in dull coals, and small in brown coals. The distance between cleats may vary from 0.25 cm in low volatile bituminous coals up to 91 to 122 cm in Lignite (Ting, 1977).

Although most of the coals possess a well defined cleat network with cleat spacing less than 1 cm, it does not mean that they necessarily have an effective permeability. For example the coals of Manville group of Alberta and the Cameo coals of Colorado have well defined cleat systems but the permeability of the coals is extremely low (Clarkson and Bustin, 2011).

The success in the cavity completion method in coalbed methane reservoirs is more probable when cleats are closely spaced, but coals with high cleat density are also more susceptible to damage while drilling and completion operations (Ramurthy et al., 1999, Weida, December 1993). Table 2.2 shows the cleat spacing for well known coals around the world.

Table 2.2: Cleat spacing for different types of coal (Bell, April 1989, Purl et al., 1991, Gray, 1987)

	Cleat spacing range (mm)
Australian coals	20-150
Western US coals	12.7-25.4
Northern Appalachian basin	20-30

Volatile evaporation and coal dehydration are the two proposed mechanisms responsible for creation of cleat system in coal. Also, tectonic activities in the area and coal compaction can result in formation of fractures in coal. Cleat planes may be filled by carbonates, minerals and clays. In some coals a considerable part of the mineral impurity is due to the cleat fillings (Ward, 1984). Cleat filling with mineral substances has a destructive impact on fluid (gas and water) transport in subsurface coalbeds.

2.5 Coal permeability

Economical coal gas production entails finding sweet spots in reservoir where coal permeability is high allowing adequate gas and water transport in cleats. Coalbed permeability can be less than one millidarcy up to hundreds of millidarcies. The permeability of Manville coals of Alberta is 1 mD or even less and only horizontal drilling in sweet spots (high permeable zones) can result in commercial production. Most of U.S. CBM reservoirs possess a permeability of 3 to 30 mD (Palmer, 2010). Some of the Australian coalbeds have permeabilities of hundreds of millidarcies such as the case on the Undulla Nose of the Surat basin where coal permeability is as high as 500 millidarcies (Scott, 2004).

Coal permeability is due to network of connecting fractures commonly known as cleat system. Fracture density, fracture opening, fracture orientation and connectivity, matrix shrinkage, and overburden stress are influential parameters on magnitude of the permeability.

Coal permeability is stress/desorption dependent. Pore pressure reduction during water production from cleats tends to decrease cleat apertures resulting in permeability reduction. Since coal is a highly compressible rock, pore pressure reduction inside cleats can substantially reduce the permeability. While cleats get tighter because of overburden pressure, gas desorption from coal results in matrix to shrink. Matrix shrinkage enlarges the cleat opening and consequently the permeability is increased. Overburden stress and matrix shrinkage are two competing factors while one tends to decrease the permeability the other tends to increase it. When effect of matrix shrinkage overcomes the effect of overburden stress, coal permeability is rebounded.

There are various models available in literature to calculate the effect of pore pressure reduction, overburden stress, and matrix shrinkage on coal permeability (Harpalani and Chen, 1997, Palmer and Mansoori, 1998, Shi and Durucan, 2004, Zhu et al., 2011).

The model proposed by Palmer and Mansoori is widely used in CBM simulators. This model predicts matrix shrinkage effect by direct analogy to temperature expansion/contraction when porosity is small enough, which is the case in coalbeds. The following equations describe this permeability model (Palmer and Mansoori, 1998):

$$-d\emptyset = -\frac{1}{M}dP + \left[\frac{K}{M} + f - 1\right]\beta dP - \left[\frac{K}{M} - 1\right]\alpha dT \qquad (2.1)$$

here K and M are the bulk and constrained axial modulus respectively, α is the coal thermal expansion coefficient, β is the grain compressibility, T is the temperature, $\emptyset$ is the porosity and f is a constant.

The temperature term is substituted with a volumetric pressure dependent shrinkage term while it takes the Langmuir type curve. Integrating over the porosity results in the following porosity-pressure dependent equation:

$$\frac{\emptyset}{\emptyset_0} = \left[1 + \frac{C_m}{\emptyset_0}(p - p_i) + \frac{C_0}{\emptyset_0}\left(\frac{K}{M} - 1\right)\left(\frac{bp}{1+bp} - \frac{bp_i}{1+bp_i}\right)\right] \quad (2.2)$$

where:

$$C_m = \frac{1}{M} - \left[\frac{K}{M} + f - 1\right]\beta \quad (2.3)$$

and b is the adsorption affinity, $\emptyset_0$ is the initial porosity, C_0 is the initial pore volume compressibility, and p_i is the initial pressure.

Then coal permeability is calculated using the following equation:

$$\frac{k}{k_0} = \left(\frac{\emptyset}{\emptyset_0}\right)^3 \qquad (2.4)$$

Economic viability of coalbed methane production mainly depends on coal permeability and initial gas content. To meet minimum criteria for coal bed methane development, a minimum permeability of 1 mD and minimum gas content of 150 Scf/ton of coal maybe required in thin coal formations (Halliburton, 2008).

Coal beds with permeability of less than 1 mD may not be able to produce gas at an efficient economical rate. Moreover, high permeable coals (permeability greater than 100 mD) may result in inefficient dewatering operation in coal beds especially when coal is hydraulically connected to a large aquifer (Holditch, 1993). Produced water from coal bed can be easily replaced by aquifer water and consequently dewatering operation fails.

2.6 Gas content

Coal is a source rock and also a reservoir rock. A good coal bed may have a few times more gas compared to conventional gas reservoirs with the same volume. This is due to the large surface area of the coal keeping a significant amount of gas in the adsorbed form. Coal may have the surface area of $205 m^2 gr^{-1}$ available for gas adsorption (McElhiney, 1989).

Ultimate gas recovery in coalbed methane reservoirs is controlled by gas content and permeability. The gas within a coal bed exists in three different forms:

1. Free gas in natural fractures and macropores.
2. Dissolved gas in coal bed water.
3. Gas adsorbed on the coal matrix by weak dispersion attractive forces.

The amount of dissolved gas in coalbed water and the amount of free gas in fractures are negligible compared to the gas in the form of adsorbed phase.

Coalbed gas mainly consists of methane as the major component. Carbon dioxide, water, wet gases, and even liquid hydrocarbons are associated with the coal bed gas. Coalbed gas is characterized using the dryness index. The dryness index (C_1/C_{1-5}) defines the ratio of methane to heavier hydrocarbons (Scott, 1994). Table 2.4 classifies coalbed gas type based on the dryness index to extremely dry, dry, wet gas and very wet gas.

Table 2.4: Coal gas dryness index

Coal gas type	Dryness index
Extremely dry gas	>0.99
Dry gas	0.99-0.94
Wet gas	0.86-0.94
Very wet gas	<0.86

There are usually traces of carbon dioxide and nitrogen in coalbed gas. The origin of carbon dioxide in coalbed can be categorized into four sources (Clayton, 1998):

1. Decarboxylation of kerogen and soluble organic substances during coal formation.
2. Dissolution or thermal decomposition of carbonates.
3. Bacterial activities on organic substances.
4. Volcanic related activities (magma intrusion).

The amount of carbon dioxide in coalbed gas is considered a very high value when it exceeds more than 10% of the total gas. The amount of carbon dioxide in coal bed gas is classified as high with 6-10%, moderate with 2-6%, and low with less than 2% (Hanson, 1990).

Gas content of a coal bed is determined using a sorption gas canister. The recovered coal sample from well site is quickly transferred to canister to minimize the amount of lost gas from the fresh sample. The term lost gas is referred to that volume of the coal gas which is lost during sample recovery from the well and sealing for canister test. Coal sample is placed in a canister while temperature is set to the reservoir temperature. The sample is exposed to atmospheric pressure while gas rate and gas quantity accumulated in canister are measured using a volumetric instrument. When gas flow stops in the canister, the sample is crushed and the released gas is measured and recorded as residual gas quantity. The residual gas is referred to that volume of the gas remains inside the sample after desorption is effectively finished in the canister (McLennan, 1995). The residual gas is measured by crushing the sample to -60 mesh grain size and is volumetrically measured by a volumetric displacement tool. Total gas content of the coal is the summation of the lost gas, the measured gas, and the residual gas. Accurate measurement of total gas content of the coal depends on accurate estimation of the lost gas using an appropriate method. The lost gas can be calculated by backward extrapolation from an appropriate point on measured gas data when measured gas volume is plotted versus square root of time. The amount of lost gas is estimated at the zero time where measured data points intersect with the volume axis.

Gas content of coal is affected by coal characteristics such as coal rank, ash content, and moisture content. Methane is generated significantly for coals having carbon contents of greater than 85% (Das 1991). Medium to low volatile bituminous and anthracite coals with carbon contents greater than 85% are prolific for commercial coalbed methane production.

Ash content which is mainly referred to inorganic and non-coal materials reduces the gas content of coalbeds. Inorganic materials are considered inert in terms of gas sorption on coal. Dirty coals which have high percentage of mineral matters (ash content) possess lower sorption capacity compared to clean coals. Clean coals with lower amount of impurity (mineral matters) have higher percentage of organic matters which are responsible for gas sorption on coal. Furthermore, ash content has a negative impact on cleat system and therefore can reduce economic efficiency of gas production (Brown, 1994).

Presence of moisture in coal structure has significant impact on sorption characteristics of coal. Moisture removal from coal changes structural form of coal due to shrinkage effect and this may result in formation of new cleats (Levine, 1992). The inherent moisture of coal declines with rank. Coals with lower ranks, lignite, have a large volume of moisture which is steadily declined when coal maturity is increased (Berkowitz, 1979). The moisture content of low volatile bituminous coal and anthracite are reported to be as low as 1% to 5% respectively. Although the moisture content in high rank coals is low, it still has a profound impact on the sorption capacity of coal. The presence of 1 to 5% moisture can reduce the sorption capacity by 25% and 65% respectively (Rice, 1993).

Water exists in micropores has stronger adsorptive capacity compared to methane. Water competes with methane and there will be less space available for methane molecules to adsorb on micropores resulting in lower gas content of coalbeds (Dabbous et al., 1974).

The term critical moisture content describes the amount of moisture in coal above which the moisture does not change the sorption capacity of coal towards methane. It appears that after the critical moisture content in coal, excess moisture only covers coal materials and has no influence on the sorption characteristics of the coal (Joubert et al., 1973, Joubert et al., 1974).

The gas content of coal is reported in different bases. Two commonly used bases for gas content are the raw basis and the dry ash-free basis. The raw basis reports the gas content based on actual weight of the sample in canister, including the moisture content and inorganic materials in sample. When gas content is corrected for the moisture content and non-coal materials, it is reported as the dry, ash-free basis.

The gas content of coal in the dry, ash-free basis is calculated using the following equation:

$$m_{daf} = m_{raw}(1 - w_m - w_a) \quad (2.5)$$

where:

m_{daf} gas content in dry, ash-free basis

m_{raw} gas content in raw basis

w_m moisture weight fraction

w_a ash content weight fraction

2.7 Adsorption

When a gas or vapour is exposed to an evacuated solid, a part of the gas is taken by the solid. Gas molecules separated from the gaseous phase either adhere to the solid surface or enter to the structure of the solid. Gas molecules attachment to the surface of the solid is called adsorption process. The absorption is referred to the process of entering gas molecules to the solid structure. The word sorption is used to define both adsorption and absorption processes which normally occur at the same time (Brunauer, 1943).

Gas adsorption on the solid surface can be categorized as physisorption (physical adsorption) or chemisorptions (chemical adsorption). Physical or chemical nature of adsorption depends upon existing attractive forces between adsorbed molecules and the solid surface. When gas molecules are adsorbed to the solid surface using weak attractive forces (Van Der Waals forces), the physical adsorption is occurred. When there are strong interactions among gas molecules and the solid surface, the adsorption process is recognized as the chemical adsorption.

Molecules in the adsorbed phase can either attach strongly to the solid surface or move freely on the surface area. Adsorption restricts gas movement into a two dimensional area in the adsorbed phase compared to gas movement in a three dimensional space of the gaseous phase. Therefore, the energy of the system is reduced resulting in the exothermic nature of the adsorption process (Brunauer, 1943).

Since more than 98% of the stored gas in coalbeds is in the form of the adsorbed phase in micropores, it is essential to study the sorption mechanism in complex structure of the coal. There are numerous literatures on the gas sorption on solid materials including coal. In one of the primary and also important studies, in 1938, Brunauer classified gas adsorption on solid materials into five different types of isotherms (Brunauer, 1943). The first type of isotherms in this classification describes the amount of gas adsorbed on micro porous materials. Methane adsorption on coal closely follows this type of isotherm (Type I). Non- polar methane molecules are adsorbed onto coal surface by weak dispersion attractive forces resulting in the physisorption nature of the adsorption (Rouquerol et al., 1999a, Saghafi et al., 2007). The magnitude of the energy release due to methane adsorption on coal is estimated to be around 20 $KJ\ mol^{-1}$ which is half of the condensation energy of methane (Yee et al., 1993).

The theory of gas adsorption on solids developed by Langmuir in 1918 can well formulate methane adsorption on coal structure. Langmuir equation is widely used in coalbed methane industry to present the sorption capacity of coal samples. The Langmuir equation is defined by the following equation:

$$V = V_L \frac{P}{P_L + P} \quad (2.6)$$

where V_L and $P_L$are Langmuir volume and Langmuir pressure respectively. In Langmuir equation V_L is the saturation volume which is the maximum amount of gas that can be adsorbed on the coal and P_L is the Langmuir pressure at which half of the saturation capacity of the coal is occurred.

Langmuir isotherm also can be written in the following form:

$$V = V_{max} \frac{bP}{1+bP} \quad (2.7)$$

where V_{max} and b are Langmuir volume and adsorption coefficient respectively.

Adsorption coefficient indicates coal's affinity to adsorb gases and is exponentially increased with the energy of adsorption and decreased with the temperature of adsorption (Rouquerol et al., 1999b). Adsorption coefficient in Langmuir type isotherm can be estimated by the Arrhenius rate equation at equilibrium condition (Do, 1998) in which affinity is a function of temperature and is given by the following equation:

$$b = b_{\infty} e^{\left(\frac{Q}{RT}\right)} \qquad (2.8)$$

Where b_{∞} is the adsorption coefficient at a reference temperature(Pa^{-1}), Q is the heat of sorption$(\frac{J}{mol})$, $R(\frac{J}{mol.K})$ is the gas universal constant and T (K) is the temperature.

At low pressures the Langmuir equation can be approximated using the Henry's law when there is a linear relationship between the adsorbed volume and equilibrium pressure. At significantly high pressures, coal is saturated with methane and a plateau is formed. Figure 2.1 is a typical Langmuir isotherm for a coal bed methane reservoir:

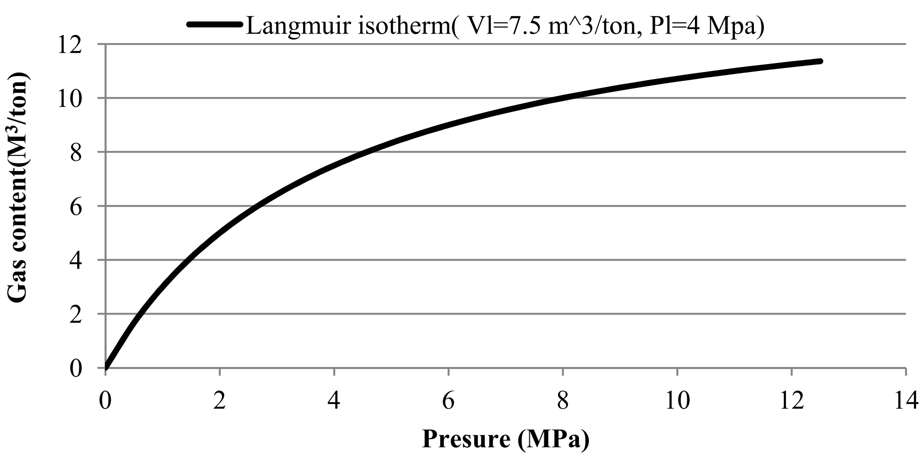

Figure 2.1: Typical Langmuir isotherm describing methane adsorption on coal

Langmuir constants are measured at laboratory for each coal sample. The adsorption data versus equilibrium pressure are required to obtain the empirical values in the Langmuir isotherm. The Langmuir isotherm can be rearranged in the following form:

$$\frac{P}{V} = \frac{P_L}{V_L} + \frac{P}{V_L} \quad (2.9)$$

When $\frac{p}{V}$ is plotted versus equilibrium pressure$p$, a straight line is obtained. The slope of the line is 1/ V_L and the intersection with the y axis is $\frac{P_L}{V_L}$.

Methane adsorption on coal samples can be measured using three different methods: the manometric technique, the volumetric technique, and the gravimetric technique. However in these techniques different physical principles are applied to measure the amount of adsorbed gas, they usually provide precise and comparable results (Gensterblum et al., 2009).

Modern high pressure gravimetric analysers utilize magnetic suspension balances to measure the adsorbed mass accurately. The contactless weighting system provides extremely accurate measurements. The coal sample is placed in a basket and the mass of the methane adsorbed on coal is measured using a contactless weighting system. The extra mass added to the coal due to adsorption changes the suspension forces and this change is transmitted to an outside balance. The use of the balance outside the system makes gravimetrical analysers highly useful under extreme pressure and temperature conditions. The fluid bulk density is measured directly by a calibrated sinker. Direct measurement of the methane mass and the fluid bulk density are valuable for near critical conditions when equations of states are not applicable (Pini et al., 2006). Figure 2.2 is the schematic of a high pressure gravimetric analyser using magnetic suspension technique for the weighting system.

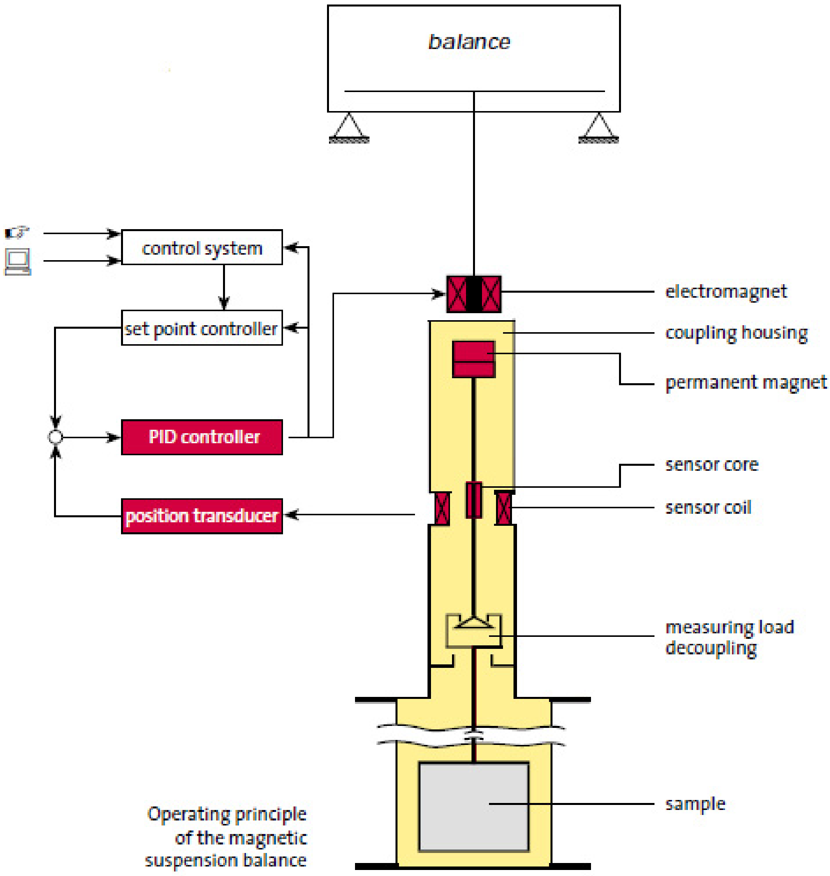

Figure 2.2: RUBOTHERM gravimetric system (graph is taken from RUBOTHERM website (RUBOTHERM))

The manometric method is widely used to measure the amount of adsorbed methane on crushed coal samples in the laboratory. Then an isotherm is constructed to establish the relationship between the adsorbed methane and the equilibrium pressure at constant experimental temperature.

Figure 2.3 is the basic schematic for a manometric experimental set up. The apparatus consists of a sample cell and a reference cell which are located in an air or a water bath. The bath is used to keep the temperature constant at the desired experimental temperature. There is a vacuum pump connecting to the apparatus. The vacuum pump creates suction inside the set up to take all the air and residual gases out of the system. The pressure transducers record the pressure precisely during the experiment. There are two pressure transducers working under different pressure conditions. The high pressure transducer records high pressures and is less accurate than the low pressure transducer. The low pressure transducer is highly accurate and sensible to the low pressures.

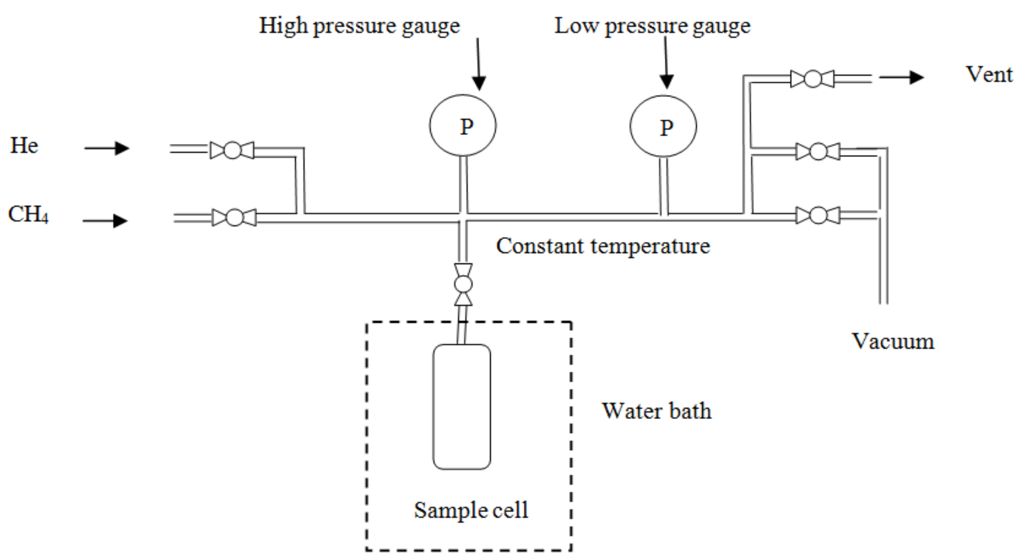

Figure 2.3: Manometric experimental setup

The following steps are usually taken to measure the amount of adsorbed methane on a coal sample:

1. The coal sample is crushed and sieved to obtain uniform particle sizes (particles that pass through the -60 mesh size) (Mavor et al., 1990). Then it is placed in the sample cell and properly sealed.
2. The system is vacuumed to make sure that all the air, residual gases and moisture have been extracted from the set up. Normally sample cell is heated during the vacuum facilitating extraction of residual gases and moisture from the sample particles. However caution should be exercised not to heat the sample over the boiling point of volatile matters. Evaporation of volatile matters changes the original structure of the coal and sorption results do not represent sorption characteristics of the original sample in the sample cell.
3. Dead volume of the set up is measured using a helium porosimeter. Helium adsorption on coal is negligible and it can be used to measure the void space in the sample and also the cells that are accessible to the gas.
4. Helium is vented out and the set up is vacuumed again.
5. Reference cell is pressurized with methane and the stabilized pressure is recorded as the reference pressure.
6. Methane is exposed to the sample cell when the automatic valve is opened connecting the sample cell to the reference cell and the final pressure is recorded. The amount of methane adsorbed on the coal sample is calculated using an equation of state based on initial and final pressures and the set up temperature.
7. Methane is alternatively added to the reference cell and methane adsorption on coal sample is measured when equilibrium pressure is achieved.

The adsorption isotherm is constructed from the adsorption data attained from the experiment. The amount of adsorbed methane is plotted versus the equilibrium pressure in a normal scale showing the sorption behaviour of the coal sample. The adsorption isotherm is meaningful when the equilibrium is achieved for all the pressure steps. The time to reach to equilibrium is a function of many factors including coal type, particle size, and experimental temperature. Equilibrium time is less dependent on the particle size when coal particles having a size above 0.5 mm and this is due to the presence of micro-cleats dispersed in the coal particles (Siemons et al., 2003).

Equilibration time for sorption experiments can be attained by plotting the pressure history of each step versus the logarithm of time showing the whole picture of the sorption process(Clarkson and Bustin, 1999b). Table 2.3 summarizes the equilibration time reported by different authors to achieve the equilibrium pressure for methane and carbon dioxide sorption experiments on different coals (Battistutta et al., 2010).

Table 2.3: Equilibration time for sorption experiments on coal samples with different sizes

Authors	Equilibration time (h)	Temperature (K)	Grain size (μm)
(Majewska et al., 2009)	440	298	20000×20000×40000
(Battistutta et al., 2010)	336	318-338	1000-2000
(Goodman et al., 2006)	96	328	250
(Gruszkiewicz et al., 2009)	50	308-313	1000-2000
(Siemons and Busch, 2007)	20	318	200
(Clarkson and Bustin, 1999a)	7	273	1840
(Chaback et al., 1996)	6-18	300-320	93-300
(Day et al., 2008)	4	326	500-1000
(Busch et al., 2006)	1	318	63-2000
(Goodman et al., 2004)	0.5-12	295-328	250

Figure 2.4 is the hypothetical demonstration of the different stages of methane adsorption in the coal micropore as pressure increases.

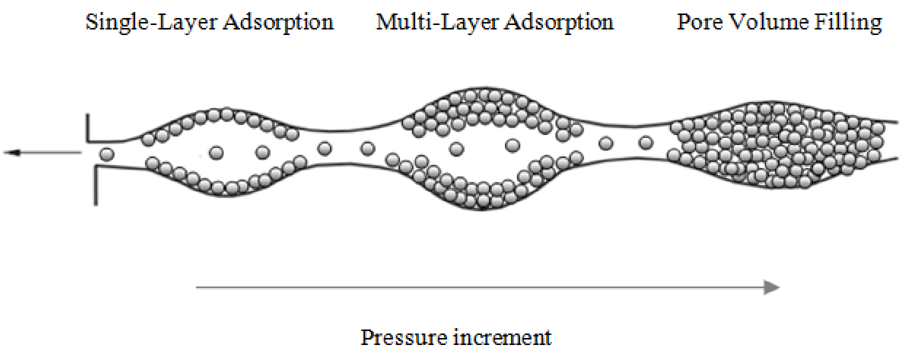

Figure 2.4: Different stages of methane adsorption in a micropore

Single site adsorption is happened at low pressures when methane molecules sit on the adsorption sites away from each other. When the pressure progresses, single layer adsorption is occurred with all the adsorption sites filled with one layer of methane molecules. At high pressures, multi layer adsorption is happened when layers of adsorbed molecules form on top of each other. The adsorption process is viewed as the micropore volume filling at ultra high pressures meaning the pores are filled with methane and the density of the adsorbed phase reaches to the liquid density (Milewska-Duda et al., 2000).

2.8 Gas diffusion coefficient in coal

Gas flow in micropores is well described by the diffusion process. The diffusion process in micropores is believed to be a combination of different types of diffusion mechanisms including molecular, Knudsen and surface diffusion (Smith and Williams, 1984).

Molecular diffusion is normally occurred in large pores with molecule- to-molecule collision as the dominant process. Knudsen diffusion is occurred in pores having the size smaller than the mean free path of the molecules. In Knudsen flow, molecular collision with the wall of the pores is happened before molecule to molecule collision. Surface diffusion describes molecular movement when molecules are transferred in the adsorbed phase from one site to the adjacent site.

The simplest approach to model gas flow in micropores is based on Fick's second law when all the pores are of the uniform size. The gas flow equation in a homogenous spherical particle with all the pores of the same size takes the following form (Crank, 1975):

$$\frac{D}{r^2}\frac{\partial}{\partial r}\left(\frac{r^2 c}{r}\right) = \frac{\partial c}{\partial t} \qquad (2.10)$$

here r is the sphere radius, t is the time, c is the gas concentration, and D is the effective diffusion coefficient. When the initial concentration in the sphere is C_i and gas concentration is kept constant at the surface of the sphere, the analytical solution of the fractional uptake can be obtained using this equation (Crank, 1975):

$$\frac{M_t}{M_\infty} = 1 - \frac{6}{\pi^2}\sum_{n=1}^{\infty}\frac{1}{n^2}\exp\left(-Dn^2\pi^2 t/a^2\right) \qquad (2.11)$$

Here M_t/M_∞ is the fractional uptake, D is the effective diffusion coefficient, t is time, and a is the sphere radius. The fractional uptake is the amount of gas adsorbed at each time divided by the total amount of gas adsorbed at the equilibrium pressure.

Experimental fractional uptake is measured at each equilibrium pressure. The amount of adsorbed gas is calculated using an equation of states (EOS) during the adsorption process and then it is divided by the total amount of adsorbed gas at that equilibrium pressure. The experimental fractional uptake data is plotted versus time for each equilibrium pressure. Then the effective diffusion coefficient in the analytical solution of the fractional uptake is chosen in a way to obtain the best match between the experimental and analytical uptakes. The effective diffusion coefficient for the system of uniform pores is widely used in available reservoir simulators.

A large portion of the gas adsorption in coal is occurred at early times of the adsorption process followed by slow adsorption for the rest of the experiment. Coal has a dual stage diffusion process which is due to dual porosity nature of the coal (Ruckenstein et al., 1971). A dual stage diffusion model can well describe the diffusion process in coal. In 1971, Ruckenstein developed an analytical model for sorption in solids with dual porosity system reflecting the macro- and micro structure of the solid. In this approach, first diffusion occurs in macropores at a relatively fast rate compared to the micropores followed by a slow diffusion in micropores. The final uptake at anytime is the summation of the uptakes in micropores and macropores (Ruckenstein et al., 1971).

$$\frac{M_t}{M_\infty} = \frac{M_a + M_i}{M_{a\infty} + M_{i\infty}} = \frac{\frac{M_a}{M_{a\infty}} + \frac{M_i}{M_{i\infty}}\left(\frac{M_{i\infty}}{M_{a\infty}}\right)}{1 + \frac{M_{i\infty}}{M_{a\infty}}} \qquad (2.12)$$

here M_t/M_∞ is the fractional uptake, M_a is the uptake at macropore, M_i is the uptake at micropores, $M_{a\infty}$ is the total uptake in macropores at equilibrium condition, and $M_{i\infty}$ is the total uptake in micropores at equilibrium condition.

When the uptakes in macropores and micropores are independent, the fractional uptake takes the following form:

$$\frac{M_t}{M_\infty} = \frac{\left[1 - \frac{6}{\pi^2} \sum_{n=1}^{\infty} \frac{1}{n^2} \exp\left(-D_a n^2 \pi^2 t / a^2\right)\right] + \frac{M_{i\infty}}{M_{a\infty}}\left[1 - \frac{6}{\pi^2} \sum_{n=1}^{\infty} \frac{1}{n^2} \exp\left(-D_i n^2 \pi^2 t / a_i^2\right)\right]}{1 + \frac{M_{i\infty}}{M_{a\infty}}} \qquad (2.13)$$

Here D_a and D_i are the effective diffusion coefficients in macropore and micropore respectively, t is time, a is the macropore radius, and a_i is the micropore radius.

Gas diffusion in coal can also be determined directly from the diffusivity. The term diffusivity $\left(\frac{D}{r^2}\right)$ is referred to the diffusion coefficient divided by the square of the distance at which diffusion is occurred. The diffusivity can be directly measured from the desorption data attained from the desorption canister at the reservoir temperature.

Diffusivity is normally calculated from the sorption time. Sorption time is the time required to desorb 63.2% of the total amount of gas from the coal. Sorption time provides a qualitative tool to approximately assess the diffusional characteristic of the coal. It indicates how fast gas is released from the coal and diffuses through the matrix. Sorption time plays an important role controlling the initial gas production rate (McLennan, 1995). Sorption time should only be used as a guide to approximate the rate of gas release and shouldn't be mistakenly used for total gas recovery evaluation. Total gas recovery depends on the gas content and the permeability of the natural cleats. The following relationship exists when coal undergoes constant pressure desorption (King et al., 1986):

$$\frac{\Delta V}{V_T} = 1 - \frac{1}{e^{\sigma D t}} \quad (2.14)$$

here:

ΔV: Total gas desorbed from the coal at time t, scf/ton

V_T: Total gas content, scf/ton

σ : Matrix shape factor, cm^{-2}

D: Diffusion coefficient cm^2/s

t: Time, seconds

This relationship can be rearranged in the following form to incorporate sorption time to the equation:

$$\frac{\Delta V}{V_T} = 1 - e^{-t/\tau} \quad (2.15)$$

Here τ is the sorption time in seconds and is defined by the following equation:

$$\tau = \frac{1}{\sigma D} \quad (2.16)$$

When desorption time in the canister reaches to the sorption time, the ratio of total amount of desorbed gas to total gas content is calculated by the given equation:

$$\frac{\Delta V}{V_T} = 1 - e^{-1} \approx 0.632 \quad (2.17)$$

This value defines the sorption time at which approximately 63.2% of the gas is released from the sample.

Sorption time is widely used in reservoir flow simulators to calculate gas and water flow in coalbeds. Since sorption time encompasses the diffusion coefficient and the shape factor, it has the advantage of simplicity over using the diffusion coefficient and the shape factor separately. Shape factor depends on the fracture geometry and is difficult to measure due to the variation in the reservoir.

2.9 Gas transport modelling in coal bed

Dual role of coal as the source rock and also the reservoir rock creates special fluid flow system in coalbed methane reservoirs. Gas flow in coal is occurred in two different scales (King et al., 1986):

1. Gas flow in the coal matrix having a concentration- driven mechanism.
2. Gas flow in the fracture network having a pressure- driven mechanism.

Gas flow in coal matrix is a diffusion type flow and the gas rate depends on the matrix diffusivity. Diffusion process is generally modelled using the Fick's law describing the molar gas rate as a function of the concentration gradient and diffusion coefficient as a constant factor.

Gas flow in naturally occurred cleats is commonly described by the Darcy law. Darcy equation formulates pressure –driven gas flow in cleats and permeability is the parameter evaluating the coal conductivity. Absolute permeability of the coal bed depends on the fracture characteristics of the coal including fracture spacing, frequency, orientation, and degree of mineral filling (Laubach et al., 1998).

King and Ertekin classified the available coal bed methane models in the literature into three groups (King et al., 1986): Equilibrium (pressure dependent), Non-equilibrium(pressure and time dependent), and empirical sorption models. In equilibrium models desorption process is assumed instantaneous and the kinetics of the process is neglected. It means that gas flow in matrix is independent from the time and it flows to the cleats as soon as it is desorbed from the coal matrix. When cleat density is high and/or the diffusion coefficient is large the assumption of the instantaneous desorption can be applied and equilibrium approach is adequate (Clarkson and Bustin, 2011). Equilibrium formulation of gas flow in coalbeds is a simple approach resulting in development of single porosity models.

Non equilibrium models (pressure and time dependent) are more realistic in defining gas transport in matrix and fractures which occur at different time scales. The models which are developed based on the non equilibrium approach are dual porosity models describing gas flow in micropores and cleats. Gas transport in micropores is diffusion dominated and normally formulated using the second Fick's law while transport mechanism in cleats and/or macropores is formulated by the Darcy Law. Many models have been developed to simulate gas flow in coal beds (Gilman and Beckie, 2000, King et al., 1986, Ozdemir, 2009, Vorozhtsov et al., 1975, Wei et al., 2010). The majority of these models assume a non equilibrium approach resulting in dual porosity nature of the models. Wei et al developed a triple porosity model for carbon dioxide sequestration in coals. The triple porosity model describes gas transport in micropores, mesopores, and cleats separately. Although the multi porosity models are more realistic, they require accurate experimental measurements of the wide range of pore sizes occurring in coal.

Table 2.5 summarizes some of well known models developed to simulate gas flow in coal beds.

Table 2.5: Coal bed methane flow models

Coal bed methane flow models			
Author	Year	Approach	Description
Vorozhtsov, et al.	1975	Equilibrium model	Assumed instantaneous desorption in coal matrix and a single porosity model, the storage term was adapted to take into account the gas adsorbed on coal using the Langmuir isotherm. This model is adequate when diffusion coefficient and cleat density are high.
King et al.	1986	Non Equilibrium model	Developed a model for a single and hydraulically fractured degasification well
Gilman and Beckie	1999	Non Equilibrium model	Assumed methane as the only moving substance in the coal bed with constant viscosity at varying pressures. Methane is treated as an ideal gas. The barenblatt dual porosity concept used to model gas flow.
Ozdemir	2009	Non Equilibrium model	Modelled two phase (water and a gas phase) flow in the coal bed. The free gas is treated as a real gas and coal bed is assumed to have a dual porosity system.
Wei et al.	2010	Non Equilibrium model	Assumed a triple porosity system, multi-component adsorption, and stress dependent permeability for carbon dioxide sequestration.

2.10 CBM well completion

Permeability is the key factor in choosing the appropriate completion method in CBM plays (Palmer, 2010). In 2010, Palmer proposed a permeability base approach to classify current completion techniques based on a comprehensive data gathered from the CBM industry. In this approach coal permeability is classified into 4 different bands. Then, most efficient and successful completion techniques ,experienced in different countries with CBM activities , are assigned to each band (Palmer, 2010). Figure 2.5 shows permeability bands and the appropriate completion methods.

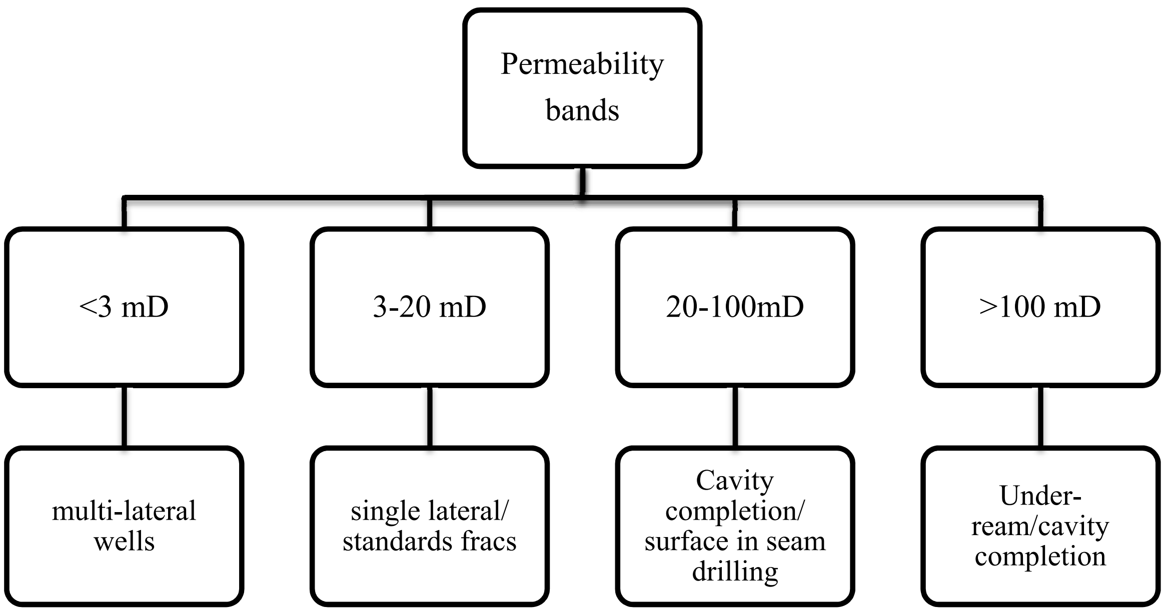

Figure 2.5: Permeability bands for coalbeds updated from (Palmer, 2010)

Coals with permeability less than 3 mD are categorized as tight coals demanding special completion techniques to achieve economical gas rates. The multi-lateral wells (trilateral, quadrilateral, or pinnate) and microholes create extensive contact area with the reservoir initiating gas flow at a high rate and producing more gas.

Coalbeds with permeabilities of 3 to 20 millidarcies are located in the low-permeability band in this classification. Normally drilling single laterals (side tracks) in the best coal seam significantly increases the productivity from the standard CBM wells. The best coal seam in a sequence of the seams is selected using the kh index (k is coal permeability and h is the seam thickness). When kh is maximum for a coal seam, that seam is chosen as the best seam (Palmer, 2010).

Coalbeds with permeabilities of 20 to 100 millidarcies are considered high permeable. Cavity completion and surface in seam drilling (SIS) are recommended for drilling and completing high permeable coalbeds. Cavity completion practice in high permeable coals of the San Juan basin in the U.S., Fairview and Spring Gully in Australia were economically successful. Surface-in-seam drilling is an Australian technique, a well is drilled to the seam and then extended along the seam and finally intersected with a production well. In this technique normally two lateral wells are drilled in each seam in a chevron pattern (Palmer, 2010).

In ultra high permeable coals (>100mD), under ream and cavity completion are the typical practices for CBM wells completion. Under reaming increases the well bore radius and also remove the skin damage adjacent to the well. High permeable coals are more susceptible to damage due to mud filtrate invasion.

2.11 Water management in CBM reservoirs

Large volumes of water are coproduced with methane from wet coal beds. Water residing in cleats maintains reservoir pressure and keeps methane in the adsorbed phase. To produce the coal gas, it is required to pump the water out creating sufficient pressure gradient in the reservoir. The produced water is brought to the surface along with gas and a decision should be made for the fate of the water. Management decision on the water mainly depends on volume of the water and water composition. Generally coalbed wells produce more water than conventional gas wells. The produced water volume can be as low as a few hundreds of litres up to hundreds of thousands of litres per day per well (CSIRO, 2011a). Over time, the volume of the water coproduced with methane at the surface is reduced and the area around the wellbore is drained from water. When coalbed is hydraulically connected to a strong aquifer, the water discharged from the coalbed can be easily replaced by the aquifer water making dewatering operation inefficient. This may result coal bed project to be left undeveloped.

Normally the total dissolved solids (TDS) in the produced water from coalbeds ranges from 200 (mg/L) up to 170,000 (mg/L) and changes from one basin to another one. The coal water with 200 (mg/L) and 170,000 (mg/L) of solids concentration are classified as fresh and saline respectively. Mostly coal water possesses a better quality compared to the produced water from conventional oil and gas wells (USGS, November 2000).

Prior to making any decision on the fate of the produced water, the water should pass adequate treatment to ensure it meets all the environmental and governmental requirements for reuse or disposal purposes. The choice to reuse or dispose the water depends on the water composition and the treatment cost. If the produced water is fresh, it can be used for the water supply after careful treatment. Also, the water can be used for irrigation in local areas. When treatment cost and water salinity are high, the coal water is reinjected into underground formations where formation water is compatible with the injected water. Tough environmental regulations prohibit water disposal in surface pits which was previously a normal practice. The cost of water treatment and disposal is different in different countries. Ham and Kantzas reported cost of 0.04 $/STB up to 2 $/STB for water treatment and disposal in coal seam gas industry (Ham and Kantzas, 2008).

Considering borderline economic efficiency of coal seam gas industry, it is vital to manage the water production from coal beds to maximize the profitability of gas production from coal seams by minimizing the water production.

2.12 Enhanced coalbed methane recovery (ECBM)

Unprecedented growth of worldwide demand for clean and sustainable energy resources requires finding new techniques to deplete energy resources more efficiently. Recent achievements in drilling techniques and technologies as well as the significance of carbon dioxide geo sequestration in unmineable coal formations have made CBM resources an attractive economical option. To fulfil the worldwide gas demand, it is desirable to introduce enhanced recovery techniques in CBM plays. To meet production goals in future, following targets should be achieved:

1. Increase total recovery from coalbed resources
2. Produce gas more quickly
3. Maximize gas production while water recovery is minimized
4. Improve profitability of CBM activities

Both gas rate and ultimate gas recovery can be improved using enhanced techniques. Infill drilling can be viewed as an option to produce gas more quickly and shorten the production time of the reserve. Shortening the production time is beneficial in terms of time value of the money. The additional cost associated with drilling new wells in a CBM reservoir might be justified when the value of the money is calculated on a discounted rate. The number of wells as well as their locations should be optimized in an infill drilling program in a specific period of time to reduce the investment return time.

Currently there are two techniques to enhance gas production from coalbeds. The first method is named methane stripping (Wo and Liang, 2004) in which nitrogen is injected into the coalbed to decrease the partial pressure of methane. In conventional method, dewatering operation is used to reduce the reservoir pressure down to the critical desorption pressure and subsequently methane desorption is initiated. Nitrogen is cheap, abundant, and an almost a non adsorbing gas on coal. Nitrogen injection into the coal bed reduces the partial pressure of the methane in the natural fissures and consequently creates stronger methane concentration gradient among the fractures and the coal matrix. Methane desorption is facilitated at higher concentration gradients. One of the advantages of nitrogen injection into the coal bed is to maintain higher reservoir pressure reducing the negative impact of overburden stresses on the permeability.

High initial methane production rates are attained through using the nitrogen injection technique; however, since nitrogen adsorption on coal is very low, fast breakthrough is occurred. The early breakthrough of nitrogen at production wells requires separation process at the well head. The cost of nitrogen separation at the wellhead and the requirement for additional surface facilities might affect the economics of this method.

Implementation of Tiffany unit pilot plan in the San Juan basin in the United States provided valuable information for nitrogen injection technique. The Tiffany unit in the San Juan basin has overall of 48 wells with 12 injecting wells and 36 producers. After 4 years of nitrogen injection, five times increase in total methane recovery was acquired due to the nitrogen injection. Nitrogen breakthrough occurred in almost all wells after one year and %20 nitrogen impurity in coal gas was reported (Wo and Liang, 2004).

The second method for enhanced gas recovery from coal beds is the carbon dioxide injection. The higher adsorption affinity of coal toward the carbon dioxide is the fundamental idea of this method. Carbon dioxide sorption capacity in coal is almost twice that of methane and is six times more than nitrogen (Saghafi et al., 2007). Carbon dioxide molecules can replace the methane molecules in coal and as a result of that methane is desorbed. The breakthrough of carbon dioxide in coal bed is slower than nitrogen because it is strongly adsorbed to the coal while flowing inside the fractures (Zhu et al., 2003). Carbon dioxide injection when compared with nitrogen injection results in slower initial production rates however the ultimate recovery of the gas is faster using carbon dioxide injection technique. This method has recently become an interesting recovery option due to the urgent need of carbon dioxide sequestration to mitigate the emission of greenhouse gases.

2.13 Infill drilling in CBM reservoirs

The term infill drilling is referred to drilling additional wells in the reservoir to boost gas production rate. The successful implementation of an infill drilling program in a CBM play requires investigation of the following four factors (Gould and Sarem, 1989):

1. Geological description of the reservoir.
2. Production mechanism of the coal bed.
3. Infill program design.
4. Economic evaluation of the infill program.

If geological picture of the reservoir is poor, there is a high risk of failure of the infill program. Accurate assessment of infill drilling programs is acquired when coal lithology, depositional environment, reservoir hydrology, and faulting system are included into the geological map of the reservoir.

Both gas storage and production mechanism in coal bed are unique and different from the conventional resources. The best operational practice for production from coalbed is the minimum bottom-hole pressure to induce a great gas concentration gradient across the matrix. A higher concentration gradient facilitates gas desorption and diffusion inside the coal. Therefore, coal beds are normally completed with down-hole pumps to deliver gas at minimum bottom hole pressure condition. There are special considerations for CBM plays which differ from field to field and it is vital to identify them prior to performing any infill project. These considerations are briefly listed here:

1. Coal bed wells normally entail hydraulic fracturing and stimulation prior bringing the wells to the production phase.
2. Coal bed wells have low cost of drilling and coal targets are normally shallow.
3. Adding more wells may require increasing the water treatment facilities at surface.
4. Cost of down-hole pumps should be included into the well cost. Normally it is required to change the down-hole pumps shortly after production commences. This is due to large fine production at the early life of the production. Cavity completion and hydraulic fracturing in coal bed wells may increase fines production.
5. Coal lithology changes across the field due to the heterogeneity. Drilling in sweet spots in the reservoir increases the efficiency of the infill program.
6. Environmental issues and land access limit the land area available for new well placements.

Both well placement and the number of infill wells in the drilling program should be optimized for a successful implementation. Optimal well placement is attained when gas production is maximized while water production is kept at a minimum level (Clarkson and McGovern, 2005).

Having an accurate geological picture of the reservoir and a comprehensive infill program enable the operators to economically evaluate the success or failure of the project. Since the infill project increases the gas recovery and also accelerates the reserve production, the economic analysis should be carefully performed on a discounted rate (Gould and Sarem, 1989). The profit for the infill project is calculated based on a discounted rate to consider the time value of the money. Once the profit associated with infill project justifies drilling new wells in the reservoir, the infill project comes from the design phase to the operational phase.

2.14 Geothermal resources

Carbon dioxide generation due to burning huge amount of fossil fuels has raised environmental concerns. Renewable energies such as wind power, solar energy, and geothermal resources have recently become the centre of attention. Geothermal energy can be simply defined as the heat generated by earth and stored underground. Therefore, it is a clean and sustainable source of energy. The efficiency of energy extraction from geothermal resources depends on the temperature. Shallow ground resources possess lower temperature compared to deep hot underground resources. Generally geothermal sources are categorized into two groups: the hot dry rocks (HDR) and the hydrothermal resources also known as hot aquifers. The terms conventional and unconventional reservoirs can also be applied to the geothermal reservoirs. The shallow geothermal resources normally possess high permeability and are easily accessible. They are categorized into the conventional group. From the technological point of view they can be easily implemented and geothermal energy is extracted with lower cost. The technological requirements for geothermal energy extraction from shallow hot aquifers to deep and tight aquifers and finally wet/dry hot rocks increase. Figure 2.6 is the geothermal pyramid with shallow high permeable hot aquifer at the top of the pyramid and deep hot dry rock at the base of the pyramid (Hillis et al., 2004). From top to the bottom of the pyramid the technological requirements for energy extraction increase and the small scale conventional resources become large scale unconventional potentials. Hot dry rocks are located at the base of the geothermal pyramid and they require higher technology for development and consequently classified as the unconventional reservoirs.

Hot dry rocks are in contrast with conventional resources (hydrothermal) in that they are more pervasive, deeper, and with very low or no porosity and permeability. They should be engineered to convert them from potential resources to productive reservoirs. To capture the heat from the hot rocks, it is essential to create flow passages between injection and production wells and keep the fractures open even at high underground stress conditions. Cold water is injected into the hot target rock at high pressure. Cold water is brought into direct contact with the hot rock and is converted to the high pressure steam which is beneficial for both direct and indirect applications. For efficient electricity generation at power stations, hot water/steam of 250 °C is required (Hillis et al., 2004). These resources are valuable for several reasons. The energy extraction form hot dry rocks have minimal environmental impacts when compared with coal power stations releasing tremendous amount of sulphur dioxide and carbon dioxide to the atmosphere. The water used in these thermal systems is circulated in a closed system reinjecting back to the rock. Finally, this type of energy capturing is a highly sustainable process.

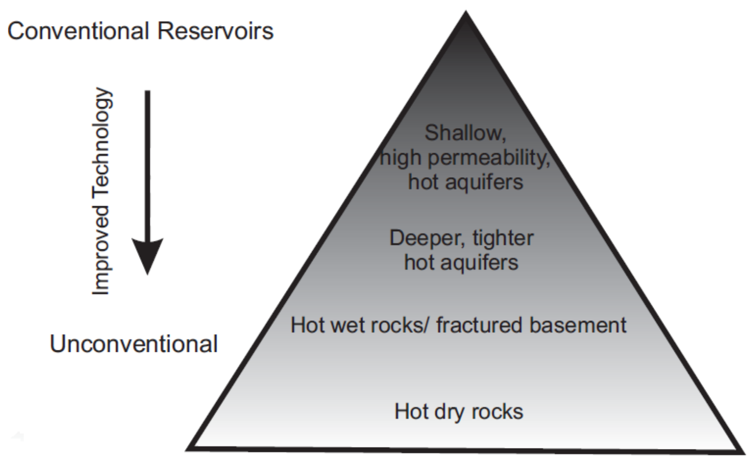

Figure 2.6: Geothermal pyramid taken from (Hillis et al., 2004)

For electricity generation at the surface the geothermal temperature should be high enough to deliver the required energy to the turbine. Unfortunately a large proportion of hydrothermal resources are left undeveloped due to low temperature which is not suitable for electricity generation with the current technology. Furthermore, the resource locations in remote areas away from the electricity lines affect the economics of the geothermal development. Therefore, hydrothermal resources have minor contribution to electricity generation. On the other hand, they are widely used for direct heating purposes. Direct use of geothermal resources is beneficial for economic and environmental reasons. From the economical point of view, there is low operational cost associated with the project after instalment and it also reduces fossil fuels consumption. From the environmental point of view, carbon dioxide emission is mitigated and there is less need for fossil fuels burning at power stations reducing the air pollution.

Ground heat source pumps (GHSP) are used for the purpose of energy extraction from underground geothermal resources. The principle of the ground heat source pumps is based on fluid circulation between the heat source and the cold section. A fluid normally water is pumped into the heat source where heat is exchanged between the source and the injected fluid. The hot fluid is brought to the cold section and the heat is transferred then the fluid is reinjected back to the geothermal source to complete the cycle.

Direct heating has extensive industrial and agricultural applications. The industrial applications normally require steam while most of the agricultural cases can be fulfilled with geothermal water. The industrial use of geothermal energy encompasses a range of processes such as simple heating, drying, distillation, de-icing, and tempering. Figure 2.7 is an indicator of the temperature ranges required for different applications. The applications require temperatures of up to 120 °C can be handled with geothermal waters while steam is used for the cases with higher temperature requirements (Lindal, 1973).

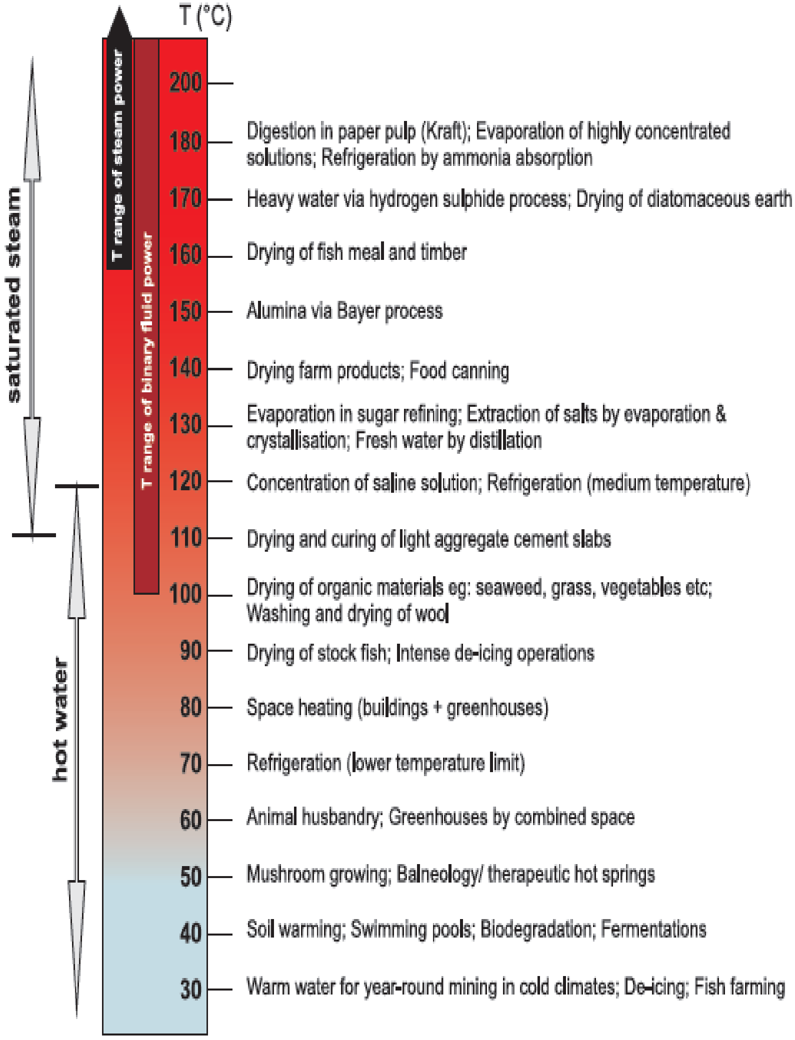

Figure 2.7: Direct use of geothermal energy (taken from Geoscience Australia, Modified from(Lindal, 1973))

2.15 Geothermal resources in Australia

Both hot aquifers and hot dry rock (HDR) geothermal resources are pervasive in Australia. Australia's geothermal resources development faces challenges due to both resource locations and resource temperature. They are normally located in areas distant from populated and major cities and possess low temperature. Therefore, the economics of the geothermal resources is questioned with the current technologies. The abundance of geothermal resources across the Australia is the result of the special geological setting. The existence of massive and hot granite rocks at the depth of 5000 metres or less combined with the overlying sedimentary rocks acting as insulator, create a unique condition for geothermal resources formation (Harries et al., 2006).

Most of the known Australian geothermal resources are located in the Copper basin and Great Artesian basin. Great artesian basin (GAB) is one of the largest artesian basins in the world covering almost one fifth of Australia land. It mainly underlies Queensland and some part of South Australia and New South Wales. It is estimated that more than 64900 million megalitres of water is stored in great artesian basin. Over the geological times great artesian basin has been formed by alternative deposition of permeable sandstones and impermeable siltstones and mudstones. The three major depositions at which sediments have been deposited are Eromanga, Carpentaria and Surat basins. The uplift of the margins of these basins along with erosion process resulted in sedimentation. The thickness of the combined sandstones and mudstones varies from 300 metres to 3000 meters in deeper sections. Sandstone layers exposure at surface was due to the surface erosion and then, rainfall water infiltrated the permeable sandstones. Therefore, huge water accumulation occurred in great artesian basin. The water temperature ranges from 30 °C at shallow depth to 100 °C in deep sections. Formation water with high temperature can be considered as potential hydrothermal resources when the hydraulic conductivity of the sandstones is sufficient enough to deliver water at a reasonable rate (QueenslandGovernment, 2011).

In Australia, direct heating has both domestic and industrial applications. It can be used in agriculture for the purpose of crop drying and space heating. The industrial opportunities are chemical extraction, wool processing, milk pasteurization, desalination, and water pre-heating in power stations where coal is the main burning fuel (Ayling, 2007). Currently direct use of geothermal resources in Australia is almost restricted to heating systems. The development of a system in Challenge stadium in Western Australia to heat the swimming pool is an example of direct use of geothermal resources. Another example is the spa developments in Northern Territory, Victoria, and Mornington Peninsula. Ground heat source pumps have been installed in several places in Australia including the Aquatic Centre and Antarctic Centre in Hobart and the Geoscience Australia's building in Canberra (Ayling, 2007).

There is only one operational small scale power station in Australia to date which has been developed for electricity generation from great artesian basin's geothermal resources. The small power station in Birdsville which is a small town at the border of South Australia and Queensland is able to supply a part of the town electricity. The station was installed in early 1990's to supply the electricity for the town. The water with 98 ºC is produced from an old artesian bore. The water rate from the bore is 27 litres per second produced from the depth of 1230 meters. Isopentane is used in the upgraded unit as the working fluid, resulting in higher efficiency for geothermal energy conversion into the electricity. The output power of this unit is 80 KWe and the hot water, after usage, is delivered to the town water supply (EnergyWise, November 2005).

Chapter 3: Temperature Effect on Methane Sorption and Diffusion in Coal

This chapter aims to study the impact of temperature on methane adsorption and diffusion in coal. Normally, methane adsorption on coal beds is described by the Langmuir isotherm. Dewatering time, critical desorption pressure, and ultimate gas recovery are defined based on the Langmuir adsorption isotherm. This chapter comprises of one paper entitled "Temperature Effect on Methane Sorption and Diffusion in Coal: Application for Thermal Recovery from Coal Seam Gas Reservoirs". In this paper, methane adsorption isotherms are measured for two Australian coal samples at two different temperatures. The experimental adsorption data are fitted with Langmuir model for all the obtained isotherms. All adsorption isotherms are measured using a manometric adsorption system operating at high pressures and high temperatures.

For each coal sample, at elevated temperatures, methane adsorption capacity of coal is reduced and consequently the original reservoir performance is changed. At higher experimental temperature, the Langmuir isotherm is shifted down and both the critical desorption pressure and ultimate gas recovery from the coal are increased. In addition, the effect of temperature elevation on methane diffusion coefficients in the coal matrix is studied. Methane diffusion coefficients are calculated based on the fractional uptake curves for each pressure step. The unipore model is applied to calculate the diffusion coefficient for coal samples. The diffusion coefficients are reported for each equilibrium pressure attained in this study and plotted versus equilibrium pressures.

The results of this study are used to support the idea of thermally enhanced gas recovery in coal seam gas reservoirs.

Thermally Enhanced Gas Recovery and Infill Well Placement Optimization in Coalbed Methane Reservoirs

Chapter 3

Paper title:

Temperature Effect on Methane Sorption and Diffusion in Coal: Application for Thermal Recovery from Coal Seam Gas Reservoirs

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This publication is included on pages 56-64 in the print copy of the thesis held in the University of Adelaide Library.

Chapter 4: Thermally Enhanced Gas Recovery from Coalbed Methane Reservoirs

In this chapter thermally enhanced gas production from coal bed methane reservoirs is proposed as an innovative approach to expedite gas production from the reservoir and increase the gas recovery in the treatment zone. The principle idea of thermal treatment on coalbeds has the root in endothermic nature of methane desorption from the coal surface. Prior to gas production, thermal treatment on coalbeds facilitates methane detachment from coal surface and consequently it changes the production performance of the reservoir.

Thermally enhanced gas recovery method consists of two separate phases: injection phase and production phase. In injection phase, hot water is injected into the coalbed at the injection well to gradually increase the reservoir temperature in treatment zone. At this phase, only water is produced from the producer well adjacent to the injection well. The production phase commences when the coalbed temperature is raised sufficiently to facilitate gas desorption and diffusion. In production phase, water is extracted from coalbed to reduce reservoir pressure down to elevated critical desorption pressure and consequently gas production starts afterward.

Thermal treatment on coalbed entails a sustainable source of energy to supply the required input energy. Borderline economic efficiency of coalbed methane activities and relatively low gas price make hot water/steam generation at surface impractical for injection purposes. The alternative and possible source of energy to be used for thermal treatment is the available underlying geothermal resources.

When coalbed methane reservoirs and geothermal resources coexist, the required energy for thermal treatment purposes can be transmitted from the underground geothermal source to the coalbed. A closed circulation system capable of transmitting hot water from the aquifer to the coalbed and reinjecting back the water into the aquifer is proposed as a method to thermally treat the reservoir prior to the gas production. Development of a closed circulation system connecting a geothermal resource and a coalbed is used as a direct heating system in this method. This system basically consists of a hot water production well, a reinjection well to the hot aquifer, a discharge well in the coalbed, and a production coalbed well. The hot water production well is drilled into the underlying geothermal resource and water is extracted and injected into the coal bed using the injection coalbed well. At the same time, coal bed water is discharged by the discharge well locating at a distance from the injection well. The produced water from coal bed is reinjected back to the aquifer to maintain the geothermal resource pressure and complete the water cycle. Figure 4.1 illustrates geothermal water circulation in a coal bed inside a closed system.

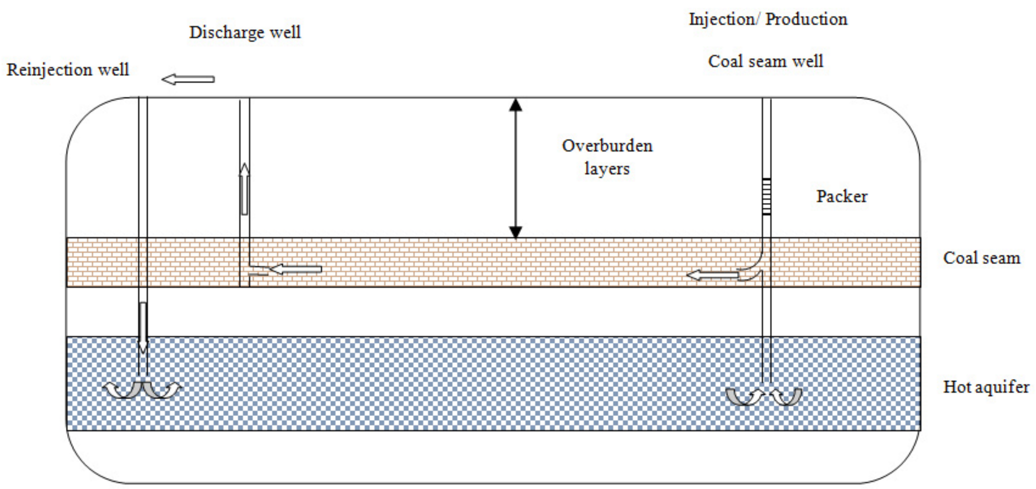

Figure 4.1: The schematic of thermal operation on a coal bed

Original water in cleats is the in thermal equilibrium with surrounding rocks having similar temperature as the contact rock. Hot water injection into the coal formation displaces the original water residing inside the cleats and natural fissures. The original water is substituted with the hot water of the underlying geothermal resources and therefore thermal equilibrium of the reservoir is dissipated. When high temperature water is brought into contact with the reservoir rock at the lower temperature, heat is transferred from the hot water to the coal formation and coal matrix is gradually heated.

The rate of heat exchange between water and coal matrix and heat flow propagation inside the reservoir depend on a number of parameters. Temperature differences between the injected water and the coal, coal matrix heat conductivity, specific heat of coal, cleat spacing, coal bed permeability, and the rate of heat loss to neighbouring formations are the main parameters affecting the thermal treatment on coalbed.

Coal beds are normally shallow and the expected temperature is 30°C to 50 °C (Katyal et al., 2007) while shallow geothermal resources possess a temperature of up to 100 °C such as the ones in the great artesian basin (CSIRO, 2011b). Some heat is dissipated due to the process of water transmission from the geothermal resource to the coal bed. The bottom hole water temperature in injector well is the final water temperature used to evaluate the heat flow in the coal.

Thermal operation on coal beds is challenging due to the low thermal conductivity and high specific heat of coal. The arithmetic mean of 0.33 $W/m.K$ was reported for the matrix thermal conductivity of a series of the American coals measured at 22 °C at the laboratory (Herrin and Deming, 1996). The thermal conductivity of the lignite, sub-bituminous, and bituminous coals are compositional dependent and moisture, ash, and carbon content define the conductivity of the coals. The higher thermal conductivity of the coal facilitates heat exchange between the hot flow stream flowing inside the cleats and the reservoir rock.

Specific heat of the coal is defined as the amount of heat required to increase the unit mass of the coal by 1 degree. Figure 4.2 compares specific heat of coal with some common types of rocks. As it is illustrated in the graph, specific heat of coal is higher than other types of rocks (Waples and Waples, 2004). For example, specific heat of coal is almost 34% more than that of limestone and sandstone. Due to high specific heat of coal, high heat delivery to the coal bed is required to thermally treat the coal bed prior to the gas production.

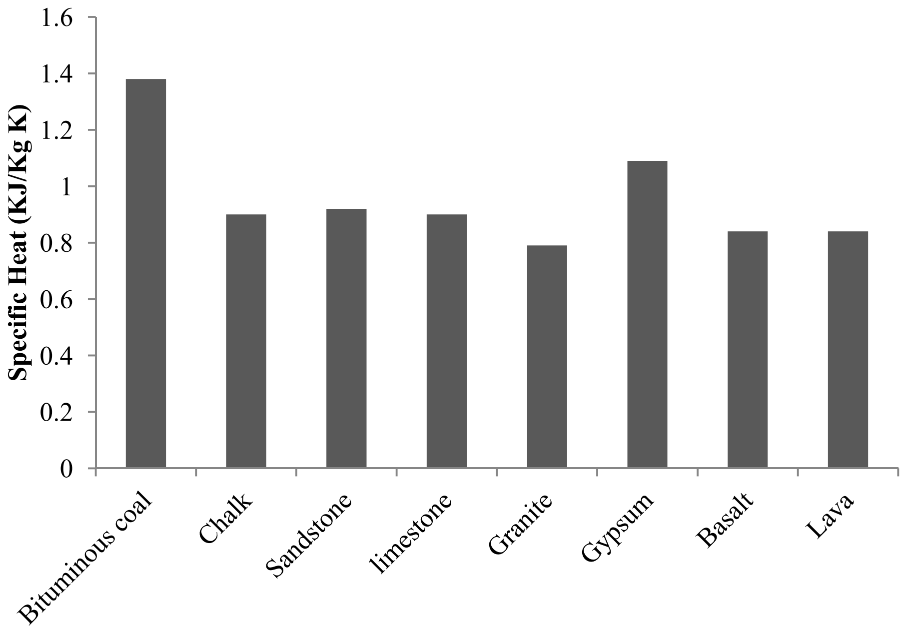

Figure 4.2: Specific heat of bituminous coal versus some common rocks

The amount of heat that can be transferred to the coal bed during thermal operation depends on the temperature difference between the hot water and the coal bed. With the assumption of an ideal system (no heat loss to the environment from the treatment zone), coal bed temperature elevation can be directly calculated using the specific heat of the coal matrix and the amount of heat transferred to the formation. The assumption of an ideal system with no heat loss to neighbouring formations overestimates the efficiency of the thermal operation. Hence, the risk of success or failure of the thermal operation increases.

During thermal operation on coal beds, cleat spacing defines the length over which thermal diffusion occurs in the coal matrix. When coal has a high cleat density, there is small distance between two successive cleats. The coal matrix confined with the closely spaced cleats is heated faster compared with the coal with largely spaced cleats.

Coal permeability indicates the ability of the hot water to flow in cleats and plays a significant role during thermal treatment on coalbeds. Coals with low permeability have lower chance to conduct the hot water inside the cleats across a large treatment area. If coal bed is unable to conduct the injected water over the treatment zone, the efficiency of the thermal treatment is questioned. Figure 4.3 shows the heat flow propagation in a coal formation simulated using CMG thermal simulator (STARS). An inverted five spot pattern with four producers at the corners and one injector at the centre is used to simulate hot water injection into the coal bed. The original reservoir temperature is 35 °C. The contour lines demonstrate the reservoir temperature after two years of hot water injection into the coal bed. Table 4.1 lists the parameters used in this simulation. The coal bed is simulated for four different permeabilities, 3 mD (tight coal), 20 mD (low permeable coal), 80 mD (high permeable coal), and 100 mD (ultrahigh permeable coal) to demonstrate the role of the coal permeability in heat flow propagation in the coal bed. For the tight coal (3mD), heat flow propagation is limited to a small area around the injection well and a large area is remained unaffected. Coal permeability increase to 20 mD (from tight coal to the low permeability coal) results in larger treated zone but there is still a considerable area which is left untreated due to the low coal fluid conductivity. The coal beds possess high permeability (80 mD and 100 mD) seem to be appropriate candidates for thermal operation and heat can be adequately distributed across a large area resulting in successful thermal treatment.

Table 4.1: parameters used for the hot water injection simulation

Coal seam thickness	20 m
Cleat porosity	1%
Injection well skin factor	-1
Production wells skin factor	0
Max surface water rate/Max bottom hole pressure	1200 m^3/day - 10000 kPa
Injection water temperature	80 ºC

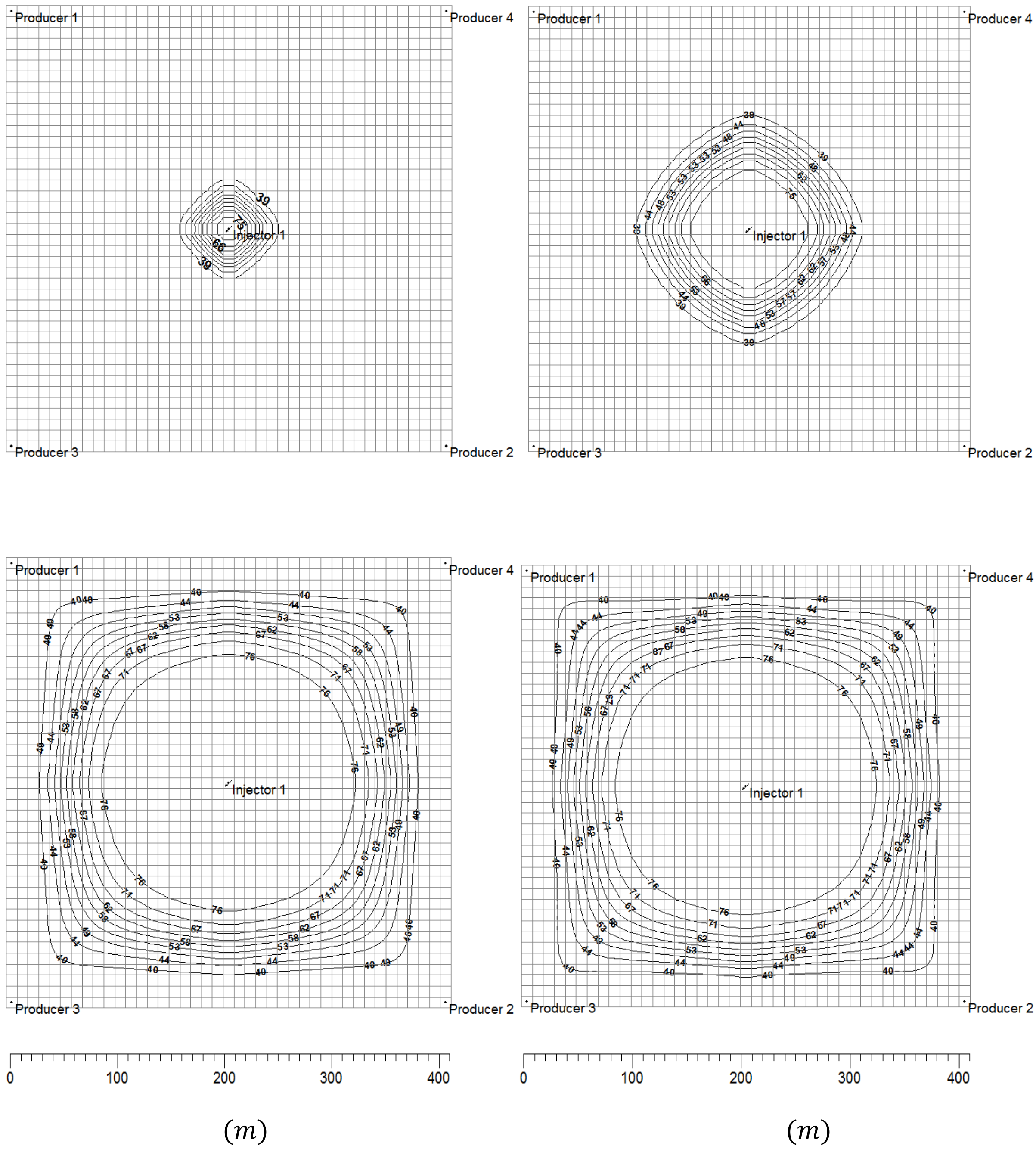

Figure 4.3: The effect of permeability on heat flow propagation in the coal bed, 3mD (top left), 20 mD (top right), 80 mD (bottom left), and 100 mD (bottom right) (the simulated area is a square)

During thermal operation on coalbed, heat is lost to neighbouring formations. Heat loss to the cap rock (overburden formation) and the base rock (underburden formation) affects the efficiency of thermal treatment on the coalbed. A portion of the heat which can be used to heat the coal is dissipated to neighbouring formations. Therefore, it is essential to incorporate the effect of heat loss into the thermal calculations to avoid overestimation of the thermal efficiency. The amount of heat loss to neighbouring formations depends on the thermal conductivity and the volumetric heat capacity of adjacent formations. The heat loss to the cap rock and base rock is simulated using the method proposed by Vinsome and Westerveld (Vinsome and Westerveld, 1980).

Figure 4.4 is the vertical cross section of a coal bed demonstrating heat flow propagation in a five spot pattern wells configuration. The two graphs show that heat flow distribution in the coal bed with and without heat loss to the neighbouring formations. The top one illustrates temperature distribution after injection period when no heat is lost to the adjacent formations. Coal is heated uniformly around the injection well located at the centre of the wells configuration. Since no heat is lost to the environment a large area is heated uniformly from top to bottom of the coal layer and cylindrical temperature distributions are formed around the injection well.

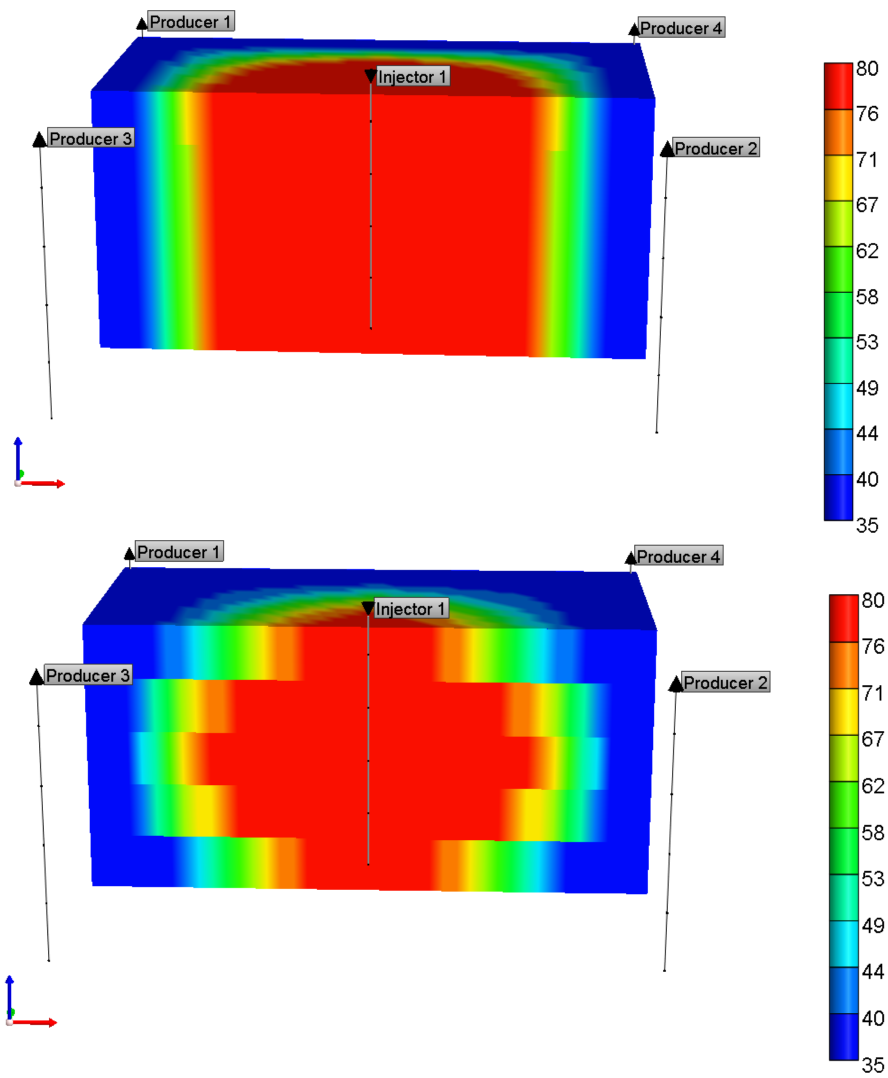

Figure 4.4: heat flow propagation in the coal bed with and without heat loss

The second graph at the bottom shows the temperature distribution in the coal bed when heat is lost to the cap and base rocks. Heat transfer to the adjacent layers considerably affects temperature distribution in the coal bed especially at the top and bottom sections of the coal. The major part of the heat loss to the neighbouring formations occurs from the top and bottom sections of the coal layer at the immediate contact with the formations. Top and bottom sections of the coal layer have smaller temperature distributions compared to the middle sections. As it is depicted in the figure 4.4, a biconical temperature distribution is created with the base of the cone at the centre of the coal layer and the edges pointing towards the upper and lower parts of the coal layer.

Incorporation of heat loss effect to the thermal simulation results in a more realistic investigation of the thermally enhanced gas production from coal beds. There is a considerable difference when coal is thermally treated with and without considering the impact of heat loss.

The impact of heat loss should be investigated both during thermal operation on the coal bed (water injection) and during gas production from the coal bed. During thermal operation heat loss affects the final temperature distribution achieved at the end of the injection period while gradual heat loss to the adjacent formation is continued during the gas production period.

The reservoir is gradually cooled down by the heat loss to the neighbouring formations and the temperature dependent reservoir properties alter in response to the change in the temperature. Figure 4.5 is the temperature distribution of the coal layer (top view) at the immediate contact with the neighbouring formation at different times. The temperature distributions are plotted at four times to illustrate temperature change for the rest of the life of the reservoir after injection period has been stopped. The temperature distribution immediately after stopping the water injection (top left) has closely spaced contour lines showing high reservoir temperature. After four years (top right), reservoir temperature is decreased due to the heat loss to the adjacent formations. The bottom left and right graphs show temperature distributions after eight and twelve years respectively. There is substantial change in the reservoir temperature after twelve years of heat loss to the cap and base rocks. Therefore, for accurate assessment of thermally enhanced gas production from coal beds, it is required to monitor the reservoir temperature during the gas production.

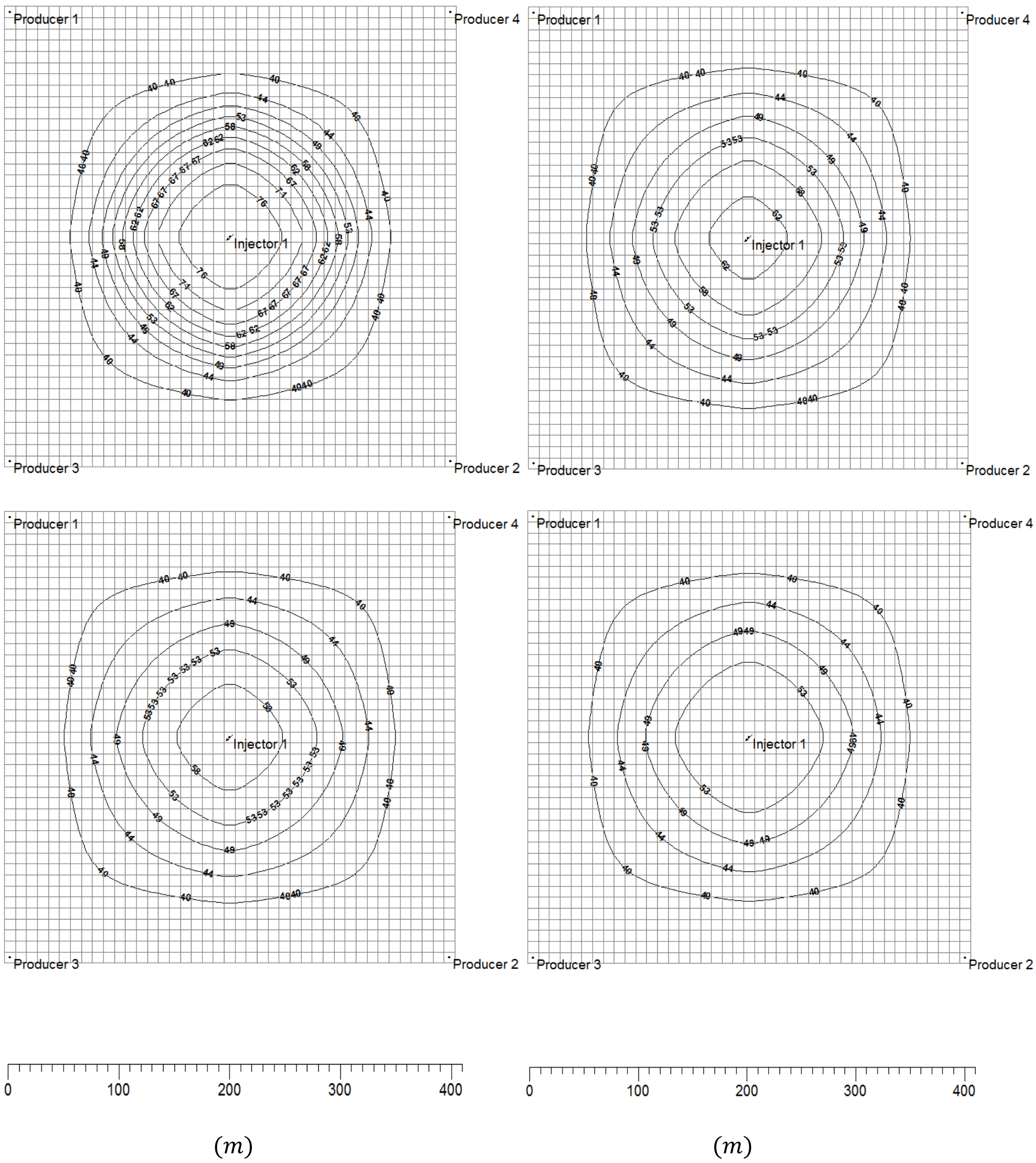

Figure 4.5: temperature distribution in coal bed versus time (the simulated area is a square)

Thermal treatment on coalbed changes some of petro-physical properties of the reservoir. To investigate thermally enhanced gas recovery from coalbeds, the impact of temperature on the following properties is studied.

- Coal permeability
- Gas adsorption isotherm
- Gas sorption time
- Reservoir water viscosity

4.1 The effect of temperature on coal permeability

Coal permeability is stress/desorption dependent. Temperature elevation results in matrix expansion and induces thermal stresses on the coal matrix. Cleat aperture is reduced by matrix expansion and there is less space available for reservoir fluid to flow inside the fracture system and consequently reservoir permeability is decreased. Figure 4.6 is the theoretical representation of matrix expansion and its impact on cleat aperture.

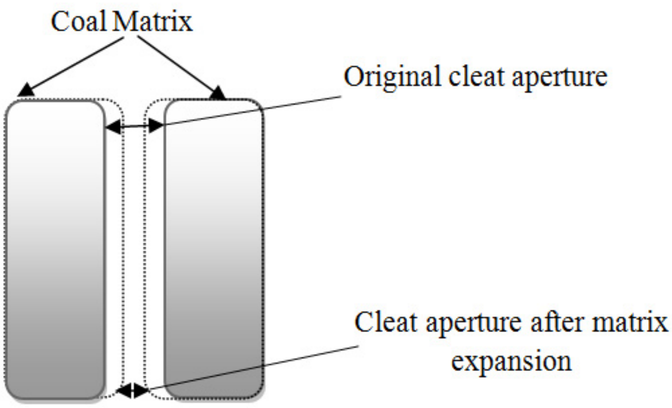

Figure 4.6: Matrix expansion effect on the cleat aperture

The magnitude of aperture decrease depends on the volumetric thermal expansion coefficient of the coal. Permeability decline due to temperature elevation can be calculated using the original Palmer-Mansoori model. Equation 4.1 shows the original equation for Palmer-Mansoori model with the temperature term at the end.

$$-d\emptyset = -\frac{1}{M}dP + \left[\frac{K}{M} + f - 1\right]\beta dP - \left[\frac{K}{M} - 1\right]\alpha dT \quad (4.1)$$

When the effect of pressure is ignored and temperature term is the only parameter affecting coal permeability, equation 4.2 can be simplified as below:

$$-d\emptyset = -\left[\frac{K}{M} - 1\right]\alpha dT \quad (4.2)$$

Where K and M are bulk and constrained axial modulus respectively, α is coal thermal expansion coefficient and T is the temperature (K).

Change of permeability as a function of temperature can be predicted by the equation (4.3):

$$\frac{K}{K_0} = \left(\frac{\emptyset}{\emptyset_0}\right)^3 = \left(1 + \frac{1}{\emptyset_0}\left(\frac{K}{M} - 1\right)\alpha(T - T_0)\right)^3 \quad (4.3)$$

Once the final reservoir temperature is achieved after thermal treatment, the cut down in coal permeability can be calculated by equation 4.3.

Figure 4.7 illustrates the change of the coal permeability solely as the function of the temperature. All the parameters used for the coal properties are listed in table 4.2.

Table 4.2: Coal properties

Coal properties for permeability reduction due to the thermal expansion	
Cleat porosity (%)	0.01
Initial permeability (mD)	80
Thermal expansion coefficient (1/°C)	42×10^{-6}
K/M ratio	0.69

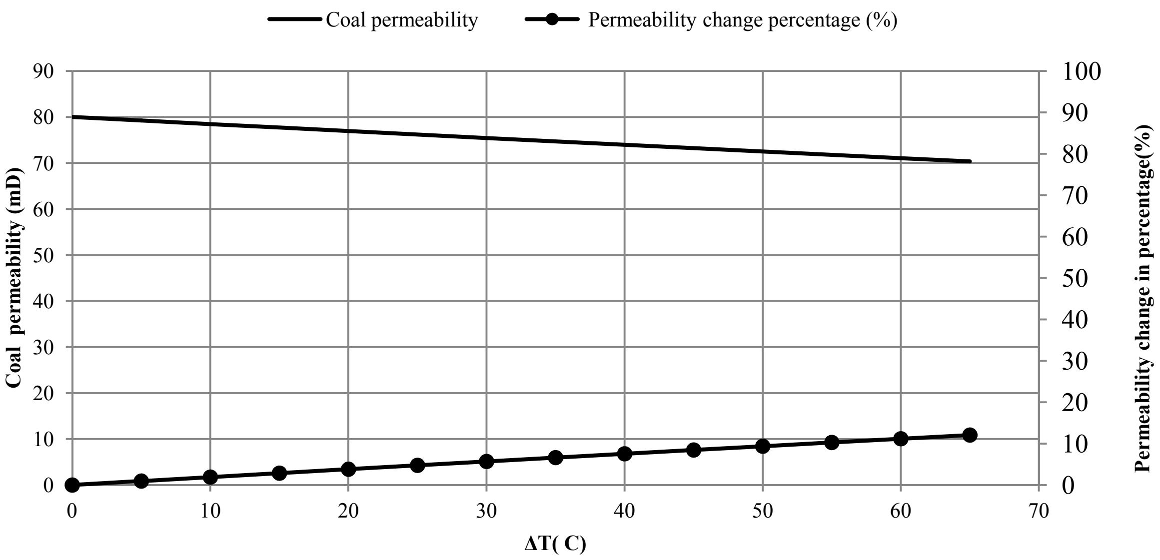

Figure4.7: The effect of temperature elevation on coal permeability

As it can be observed in figure 4.7, when coal temperature is increased by 60 °C, the original coal permeability is decreased by 10%. Therefore, thermal treatment on coal cuts down the original reservoir permeability to some extent which should be considered in thermal recovery calculations. If the matrix expansion is elastic, heat loss to the environment during the life of the reservoir can bring back the coal matrix to the original form and the lost permeability is regained due to the thermal expansion.

4.2 The effect of temperature on gas adsorption

Adsorption affinity indicates the ability of the coal to keep the gas in the sorbed phase. Adsorption affinity is temperature dependent and can be shown by equation 4.4:

$$b = b_{\infty} e^{\left(\frac{Q}{RT}\right)} \quad (4.4)$$

Here Q is the heat of adsorption, $T$is the temperature, R is the gas universal constant, and b_{∞} is the adsorption affinity at the reference temperature.

Methane molecules are adsorbed on the coal surface using non polar attractive forces resulting in physisorption nature of the adsorption. The weak attractive forces between methane and coal surface can be broken down by either pressure reduction or temperature elevation. Temperature has a substantial impact on sorption behaviour of the coal with respect to methane. Coal can accommodate considerably higher amount of methane at lower temperatures. Figure 4.8 shows Langmuir isotherms for methane adsorption on the Pittsburgh coal at different temperatures.

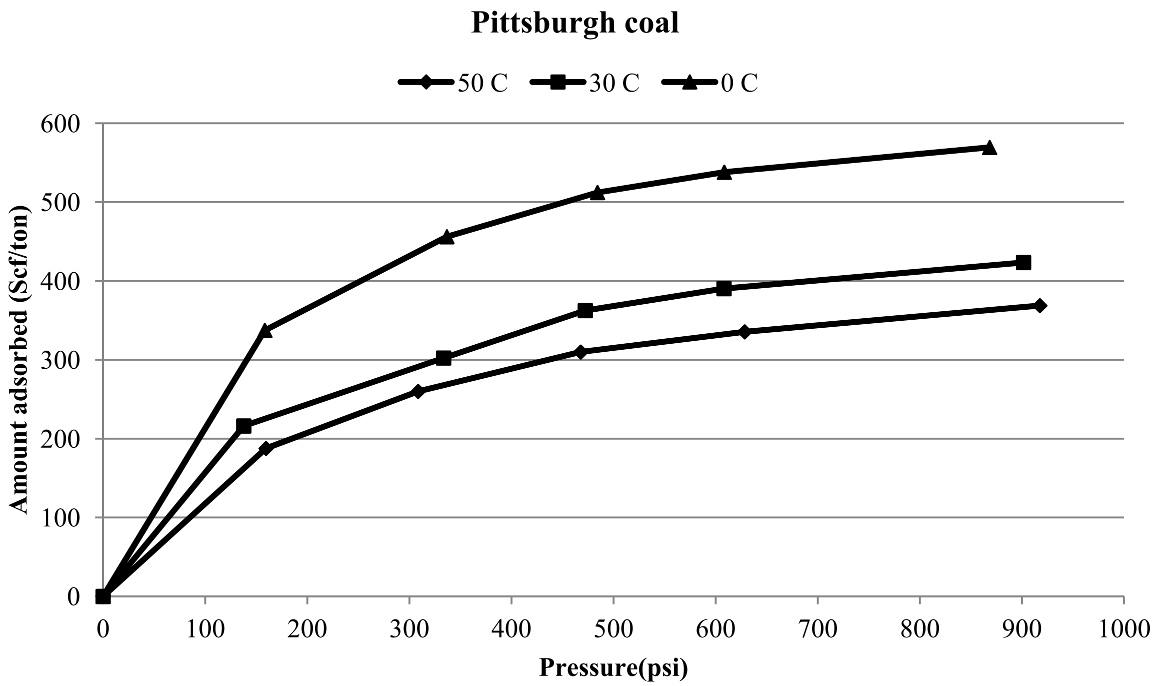

Figure 4.8: The effect of temperature on methane adsorption isotherm on Pittsburgh coal (Kim, 1977)

Methane adsorption on the coal is considerably higher at 0 °C compared to the 50 °C showing the significance of the adsorption temperature.

The linkage between methane molecules and coal surface has an energy known as the adsorption energy which is around 20 Kj for each mole of methane. Desorption process is an endothermic reaction requiring some energy to break down bonds between methane molecules and coal surface. At higher temperatures, bonds between methane molecules and coal surface are easily broken down. Any thermal treatment on coal changes sorption characteristics of the coal such that methane can be desorbed easier from sorption sites.

4.3 The effect of temperature on gas diffusion

Gas diffusion is temperature dependent and the degree of the dependency on the temperature depends upon the diffusion mechanism. Figure 4.9 is the schematic of a micropore showing three types of methane diffusion mechanisms occur in a micropore. At large pores, molecule-to-molecule interactions are dominant and gas transfer in pores is the result of molecular diffusion mechanism. Temperature elevation increases the kinetic energy of molecules and consequently molecular interactions are increased. Since molecular interactions dominate in large pores, temperature elevation substantially increases the diffusion coefficient in the pores.

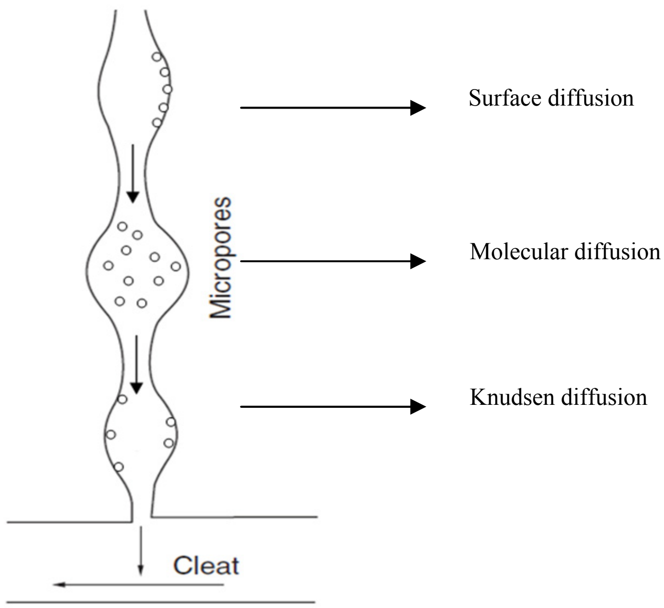

Figure 4.9: Different diffusion types in the micropore

At relatively smaller and longer pores, where mean free path of molecules is comparable to pore size, Knudsen diffusion is the dominant diffusion mechanism. In this condition, molecules repeatedly collide with the pore wall and molecular collision with the pore wall dominates gas diffusion in pores. Knudsen diffusion is less dependent on temperature compared to the molecular diffusion.

Gas diffusion which occurs on the surface of the pore wall by jumping the molecules between adjacent sorption sites is described as the surface diffusion. Like molecular diffusion, surface diffusion is also a thermally activated process and the rate is increased with temperature elevation. The Gas diffusion in narrow pores of the coal matrix is believed to be the combination of molecular, Knudsen, and surface diffusion. Generally, thermal treatment on coal bed increases the diffusive characteristics of the methane in the pore network of the coal. Temperature dependent diffusion coefficient is estimated using the following equation:

$$D(T) = D_0 \left(\frac{T}{T_0}\right)^{\alpha} \quad (4.5)$$

Here $D(T)$ is the diffusion coefficient at the desired temperature T, D_0 is the reference diffusion coefficient at temperature T_0, and α is the exponent taking the value of 0.5 when diffusion mechanism is Knudsen diffusion and 1.75 when diffusion mechanism is the bulk diffusion (molecular diffusion).

The temperature dependent form of diffusion coefficient can be averaged by equation 4.6 when both Knudsen and molecular diffusions occur in the pore system (Do, 1998).

$$D(T) = \frac{1}{\frac{1}{D_{K0}\left(\frac{T}{T_0}\right)^{0.5}} + \frac{1}{D_{M0}\left(\frac{T}{T_0}\right)^{1.75}}} \quad (4.6)$$

Here D_{K0} is the Knudsen diffusion coefficient at the reference temperature T_0 and D_{M0} is the molecular diffusion coefficient at the reference temperature.

4.4 The effect of temperature on water viscosity

The reservoir fluid in coal beds are gas and water. Temperature elevation has a constructive impact on the water production by viscosity reduction of the water at elevated temperatures. On the other hand, it has a destructive role by increasing the gas viscosity at higher reservoir temperature. Table 4.3 shows the water viscosity at different temperatures (Matthews and Russell, 1967).

Table 4.3: Water viscosity as a function of temperature (Matthews and Russell, 1967)

Temperature (°C)	Water viscosity (cP)
5	1.29
15	0.96
25	0.75
35	0.61
37	0.58
50	0.46
70	0.34
110	0.21

During thermal operation on the reservoir cold water is replaced by the hot water. The hot water possesses lower viscosity hence; it is produced at faster rates compared to the original cold water in the reservoir. In this study, the effect of temperature on methane viscosity is ignored and an averaged constant viscosity is used in simulation studies. The water viscosity at various temperatures is incorporated into the reservoir simulator based on results shown in table 4.3.

Thermally Enhanced Gas Recovery and Infill Well Placement Optimization in Coalbed Methane Reservoirs

Chapter 4

Paper title:

Feasibility Study of Thermally Enhanced Gas Recovery of Coal Seam Gas Reservoirs Using Geothermal Resources

Alireza Salmachi and Manouchehr Haghighi

Australian School of Petroleum, the University of Adelaide

Energy&Fuels, 2012, 26, 5048-5059

Salmachi, A. & Haghighi, M. (2012) Feasibility study of thermally enhanced gas recovery of coal seam gas reservoirs using geothermal resources.
Energy & Fuels, v. 26(8), pp. 5048-5059

Chapter 5: Coalbed Methane and Water Production Optimization Using Genetic Algorithm

The unprecedented growth of drilling in underground gassy coalbeds and borderline economic efficiency of CBM activities magnify the need to combine petroleum engineering and optimization disciplines to gain the maximum profit in this industry. Tens or even hundreds of shallow coal wells are drilled every year in a CBM reservoir to achieve to expected field gas rates. It is essential to determine new infill well locations intelligently to maximize the gas rate while the water production is minimized.

In this chapter an integrated reservoir simulation-optimization framework is developed capable of optimizing new infill well locations across the reservoir. Main inputs to this framework are the geological model of the desired reservoir, reservoir rock/fluid properties, operational specifications, and the number of infill wells. Figure 5.1 is a conceptual graph demonstrating the optimization framework and its components.

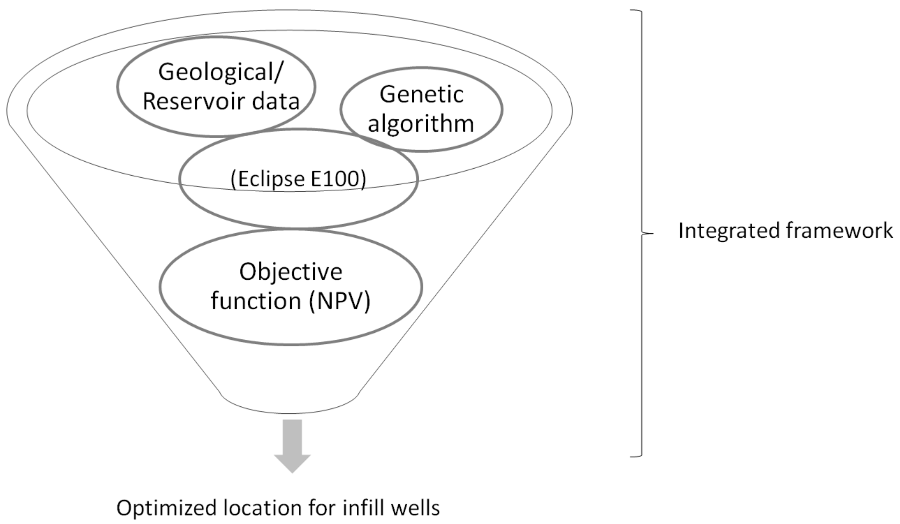

Figure 5.1: Conceptual graph demonstrating the framework

Once geological model of the reservoir is constructed based on the available geological data and topographical map of the area, it can be imported into the framework. In geological model each grid block has detailed information representing a section of the reservoir. The information such as fracture permeability and porosity, water saturation, and gas content represent the degree of goodness of a reservoir grid to be selected as an infill well location. In this study, the geological model of the Tiffany unit, the San Juan basin, is constructed from the topographical map of the area and averaged reservoir and fluid properties are uniformly assigned to reservoir grids.

Generally, the best production constrain for coal bed methane reservoirs is the minimum bottom hole pressure to create a large gas concentration across the coal matrix. A large gas concentration gradient facilitates gas desorption and diffusion in the coal matrix. Normally, a downhole pump is installed in coal wells to pump the gas and water to the surface. Depending on facilities available for water handling and treatment, the rate of water production can be adjusted not to exceed the maximum potential of surface facilities. Finally, the number of infill wells should be included into the framework. The number of infill wells depends on the number of drilling rigs, available capital expenditure, and the expected field gas rate. Also, the optimum number of infill wells that should be drilled in the reservoir can be optimized using this technique. Paper 4 fully describes how the optimum number of infill wells can be determined using the optimization technique.

Genetic algorithm (GA) is employed to distribute infill wells intelligently across the reservoir to get the best obtained cost effective scenario. The detailed description of the GA specifications used in this framework is in paper 4 and 5. The GA code of this framework is available in Appendix 1. When infill wells are distributed over the reservoir, gas and water flow in the coal bed is simulated using the reservoir flow simulator (ECLIPSE E100) to determine the gas and water production during the infill plan time span. Figure 5.2 is the flowchart demonstrating the steps taken to obtain the optimum locations of the infill wells using the framework.

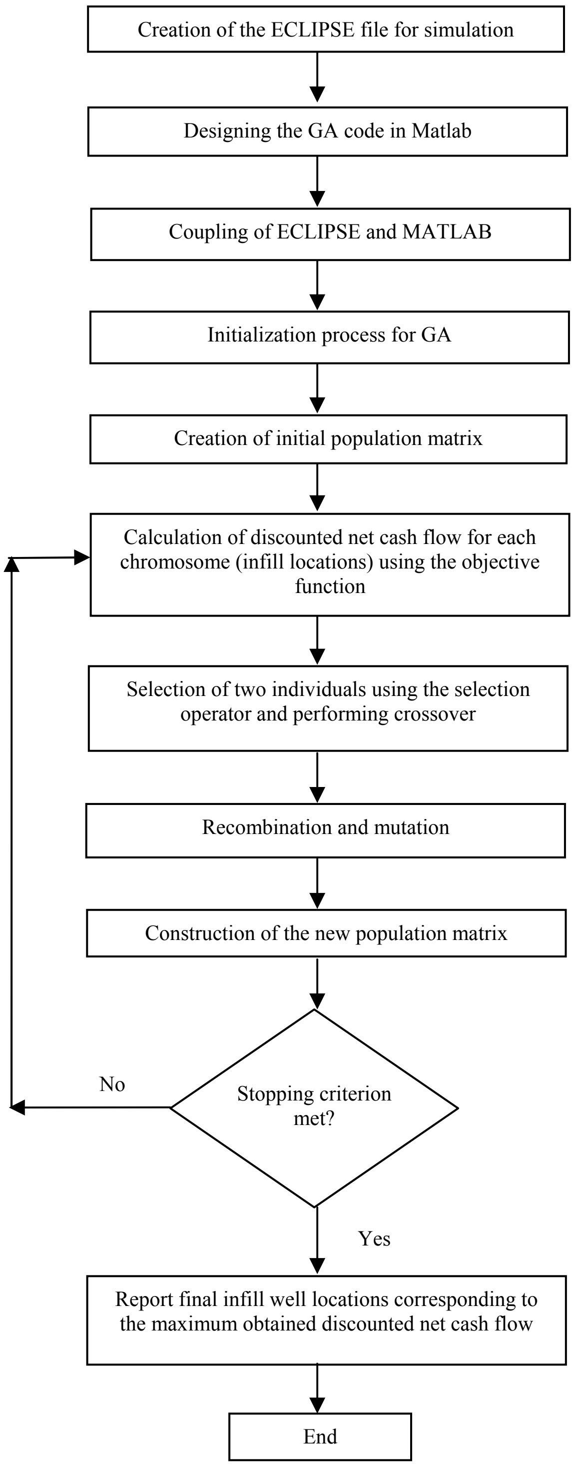

Figure 5.2: Flowchart for the integrated optimization framework

The steps shown in the flowchart are described briefly here:

1. The Eclipse model is constructed for the Tiffany unit in the San Juan basin, based on the available geological and topographical map of the area. The reservoir rock and reservoir fluid properties, locations of the existing wells, and production constrains are incorporated into the Eclipse model.
2. The GA code for this problem is programmed in MATLAB. The GA code includes the number of variables (number of infill wells) and the GA options (selection, crossover, recombination, and mutation).
3. ECLIPSE E100 and MATLAB are coupled together to work in an automatic loop.
4. During the initialization, one set of new locations is located in each chromosome (individual) and the initial population matrix is constructed. The initial population matrix is a $N_{var} \times N_{pop}$ matrix.
5. Locations of the new wells in each chromosome are assigned to the reservoir grids in the Eclipse model. Annual gas and water production are calculated with the simulator for the entire fixed period of the infill plan (10 years in this study) and saved in an Excel file.
6. Annual gas and water productions are automatically brought into the economical objective function, known as evaluation function, to calculate the discounted net cash flow corresponds to each individual and stored in a vector.
7. Using a selection operator, two individuals are selected from the vector at which the discounted net cash flows are stored.
8. The crossover, recombination and mutation are performed to construct a new population matrix. The new matrix is used for the next generation.

9. This process is continued until the stopping criterion is met. When the number of generations exceeds the maximum number of generation set in the problem, the stopping criterion has been met.
10. The goal of this approach is to maximize the discounted net cash flow of the infill plan and the output of the framework is the best obtained maximum discounted net cash flow. Finally, infill well locations correspond to the maximum discounted net cash flow are reported.

Thermally Enhanced Gas Recovery and Infill Well Placement Optimization in Coalbed Methane Reservoirs

Chapter 5

Paper title:

Infill well placement optimization in coal bed methane reservoirs using genetic algorithm

Alireza Salmachi, Mohammad Sayyafzadeh, and Manouchehr Haghighi

Australian School of Petroleum, the University of Adelaide

Journal of Fuel, 2013, Volume 111(0): 248-258

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Thermally Enhanced Gas Recovery and Infill Well Placement Optimization in Coalbed Methane Reservoirs

Chapter 5

Paper title:

Optimization and Economical Evaluation of Infill Drilling in Coal Seam Gas (CSG) Reservoirs Using Multi-Objective Genetic Algorithm

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APPEA Journal, 2013, Volume 53: 381-390

Salmachi, A., Sayyafzadeh, M. & Haghighi, M. (2013) Optimisation and economical evaluation of infill drilling in CAG reservoirs using a multi-objective genetic algorithm.
APPEA Journal, v. 53, pp. 381-390

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Chapter 6: Conclusions

Thermally enhanced gas recovery from coal bed methane reservoirs was introduced as a new recovery technique from coal beds using available underlying geothermal resources. Also, an integrated framework was developed to optimize both the location of the new infill wells as well as the optimum number of the infill wells for an infill plan. In this section, the overall conclusions observed in the thesis are shortlisted in the conclusion remarks.

6.1 Conclusion remarks

1. Temperature has a substantial impact on the methane sorption on coal samples. The adsorption isotherms were measured for two Australian coal samples at two different temperatures to investigate the effect of temperature on methane sorption and diffusion in coal. All the experimental results were fitted with Langmuir type adsorption isotherm. Results indicate that Langmuir volume of the coal is slightly decreased at elevated experimental temperature while the adsorption affinity is substantially reduced. The adsorption of the coal sample with 11.6% ash content was decreased by a factor of around 2 from $4.033 \times 10^{-7}\ Pa^{-1}$to $1.932 \times 10^{-7}\ Pa^{-1}$ when experimental temperature was increased from 308K to 348K. Adsorption affinity reduction shows that the ability of the coal to keep the methane in the sorbed phase is decreased at high temperatures.
2. The coal with lower ash content (11.6%) adsorbed more methane compared to the coal with (22.9%) ash content.
3. Results indicate that methane diffusion coefficient in coal was pressure dependent which is in agreement with the results in the literature. Methane diffusion coefficient was decreased as the equilibrium pressure was increased and it may be due to the

methane adsorption on the pore walls resulting in lower space available for methane movement in the pore network of the coal.

4. The pressure history in adsorption tests were plotted versus time to determine the equilibration time for each pressure steps. Pressure decline was plotted against the logarithm of the time for each pressure step to make sure that equilibrium condition was satisfied and adsorption data was accurate for further interpretation. Pressure decline curves for the same coal and at the same pressure step showed that at 308K equilibration time can be 2.5 times greater than 348 K.
5. Experimental fractional uptake curve for coal A was in good agreement with unipore diffusion model and it may be due to the uniform pore sizes in coal A. Therefore, a unique diffusion coefficient can well describe the methane diffusion in coal A.
6. For Coal B, experimental fractional uptake data cannot be perfectly matched with a single diffusion coefficient. Perhaps the assumption of uniform pore sizes was not applicable for the pore network in coal B. Bidisperse diffusion model provided a good match with fractional uptake data for coal B suggesting the existence of pores with different sizes.
7. For the same coal, when experimental temperature is increased, the Langmuir adsorption isotherm is shifted down. Assuming the initial reservoir pressure and abandonment pressure to be constant at different temperatures, both the critical desorption pressure and ultimate gas recovery from coal are increased. Higher critical desorption pressure and higher ultimate gas recovery at elevated reservoir temperature are the fundamentals of the thermally enhanced gas recovery from coal beds.
8. The computer modelling group (CMG) coal bed methane reservoir simulator was loosely coupled with CMG thermal simulator (STARS) to investigate the effect of thermal treatment on coal beds prior to the gas production. The model consists of an

inverted five spot pattern with the hot water injection well at the centre and four production wells at each corner.

9. Feasibility of temperature increase in the coalbed, using hot water injection, was studied by the thermal reservoir simulator (STARS). The 80 °C water was injected into the coalbed for two years and heat flow propagation was observed at the end of the injection period. The temperature distribution attained immediately at the end of the injection time is considered as the initial reservoir temperature.
10. Thermally enhanced gas recovery was investigated in terms of both gas rate and ultimate gas recovery from the coal bed. Later the results were compared with the conventional gas production to investigate the efficiency of this method.
11. Results from the simulated coalbed indicate that when coal bed is thermally treated prior to the gas production, the peak gas rate is 6.8 times higher compared to the conventional gas production. The higher gas rate and shorter dewatering period result in 58% more gas recovery from the coalbed during the first 12 years of the gas production.
12. However thermal treatment on coalbed decreases the initial permeability of the coal bed, the coal bed permeability is slightly higher during gas production using the thermal method. This is both due to higher reservoir pressure and higher matrix shrinkage during thermal technique when it is compared with the conventional method.
13. A fully automated integrated reservoir simulation-optimization framework was developed to optimize locations of infill wells in the coalbed and also find the optimum number of the infill wells in an infill plan. This framework consists of the reservoir flow simulator (ECLIPSE E100), the optimizer (genetic algorithm), and an economical objective function.

14. An infill drilling plan for the period of 10 years was designed for the case study of Tiffany unit, San Juan basin in the United States. It was observed that the optimum number of the infill wells for this reservoir with the specified economical parameters used in the study is 96. The gas price was set to be $2.5\ \$/Mscf$ and the cost of drilling and completion for each coal well was estimated to be 1 million dollars.
15. Cost of water treatment and disposal affects the locations of the new infill wells. It was observed that for fixed number of infill wells when the cost of water treatment and disposal changes from $0.04\ \$/STB$ to $2\ \$/STB$, well placements obtained by the framework changes. When the cost of water treatment is $0.04\ \$/STB$, infill wells are freely located on virgin sections of the reservoir where both coal gas content and cleat water saturation are high. Since water production/treatment is a cheap operation, cost of water treatment and disposal is not a controlling parameter in selection of infill well locations.
16. It was observed that, when cost of water treatment and disposal is high ($2\ \$/STB$), infill wells are preferably located either on the front of the water depletion zone or close to existing wells. On the front of the water depletion zone, water saturation has been lowered due to the past production but reservoir pressure is high enough for economical gas production. Infill well locations close to existing wells have the advantage of lower water production but suffer from the fact that reservoir pressure and coal gas content are low due to the depletion by existing wells.
17. The optimization problem of finding optimal locations of infill wells across a coal bed was processed using multi-objective genetic algorithm. The net present value of the infill project was split into two objectives; gas income and water expense. The optimal Pareto front for the optimization problem was attained using multi objective GA solver in MATLAB. The Pareto front contains 35 of the best obtained and non

dominated solutions. The best obtained solutions on the Pareto front were used to evaluate the economics of the infill drilling at varying gas prices and costs for water treatment.

18. Each point on the optimal Pareto front corresponds to optimum locations for 20 infill wells. These well locations were used to obtain the whole picture of the economics of the infill program.
19. An economical evaluation was performed for a 20 infill well plan in the Tiffany unit using multi-objective GA. The results suggested that when gas price is less than 2 $/Mscf, regardless of the water treatment cost, the infill project results in negative net present value meaning the infill project is unsuccessful. For gas prices around 2 $/Mscf, the net present value of the infill project is almost zero and for higher gas prices the project results in positive net present value.
20. The solutions on the optimal Pareto front are approximate and accurate calculation of net present value of the infill project requires the optimization problem to be processed using the single objective GA.

6.2 Future works

The idea of thermally enhanced gas production from coalbeds using underground geothermal resources is a fresh topic and there are many possible topics to work on. One of the possible topics is to experimentally investigate coal permeability change in respond to both temperature and desorption effects happening at the same time. This allows for an accurate permeability measurement during thermally enhanced gas production. When coalbed is cooled down by heat loss to the neighbouring formations during the gas production, two types of shrinkage occur; one is the matrix shrinkage as a result of gas desorption from the coal matrix and the other one is the matrix shrinkage due to the matrix contraction. These two effects occur simultaneously and can be modelled for more accurate investigation of the thermal method.

Another promising direction of the future research can be the development of a reservoir simulator capable of covering all aspects of the thermally enhanced coal bed production. The simulator should be able to simulate hot water production from geothermal resources and evaluate the heat loss to the surroundings until it is injected into the coal bed. Also, it should simulate heat flow propagation into the coal bed and also, gas production while heat is lost to the overburden and underburden rocks. Development of such a simulator is helpful in eliminating some of the assumptions made in this study.

Although the framework developed in this thesis works efficiently, it can still be modified for faster approach to an optimum solution. Finding the optimum locations for a large number of infill wells in an extensive reservoir is computationally expensive and the convergence to the optimum solution may be slow. Therefore the optimization code can be intelligently programmed based on numerous simulation observations to add penalty to the most improbable locations and by doing this, the convergence time to the optimum solution is decreased. A smart optimization code can reduce the computational time.

In this study, genetic algorithm was used as the optimization method. It can be a good practice to test this method against available optimization methods such as bee colony and compare the effectiveness of different optimization methods.

Chapter 7: References

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Appendix 1

GA code for single objective genetic algorithm optimization

```
Required Information
clear
clc
NoVar=40;
% based on Gibbs formula
NoPop=40;
pCross=0.9;
pTour=4;
pMut=0.2;
NoElit=1;
NoGen=100;
UBX=73;
LBX=1;
UBY=37;
LBY=1;
objfun='Evaluation'; %cost function to be optimized
objective=str2func(objfun);
%----------------
rand('seed',7)
% Generating intial population
Pop=popgen(NoPop,NoVar,UBX,UBY);
inpop=Pop;
%----------------
ItterationNo=0;
%-------------
for i=1:NoPop
    Fitness(i)=objective(Pop(i,:));
end

%-------------------
% %----------------
mine=min(Fitness)
while (ItterationNo<NoGen)
    % Mutation and Crossover
    ItterationNo=ItterationNo+1;
popmut=Scattred(Pop,Fitness,pTour,pCross,pMut,UBX,UBY);
    %-----------------------

        for i=1:NoPop
            Fitness2(i)=objective(popmut(i,:));
        end

    % %-------------------
    [ke2 ki2]= sort(Fitness2);
    %Elite
        newpop((1:NoPop),:)=popmut((ki2(1:NoPop)),:);
        [ke1 ki1]=sort(Fitness);
        popelit=Pop(ki1(1:NoElit),:);
        FitnessElit=Fitness(ki1(1:NoElit));
        Pop=newpop((1:(NoPop-NoElit)),:);
        Pop((NoPop-NoElit+1):NoPop,:)=popelit;
        Fitness(1:NoPop-NoElit)=Fitness2(ki2(1:(NoPop-NoElit)));
        Fitness((NoPop-NoElit+1):NoPop)=FitnessElit;
```

```
    %----------

    %---------------------
    SetAns(ItterationNo)=min(Fitness);
%     SetAns(end)
    FitnessGlobal=min(Fitness);
    [r Ind]=min(Fitness);
    Global=Pop(Ind,:);
    GlobalSet(ItterationNo,:)=Global;
    %%%%%SetAns(end)
    pause(0.00001)
    semilogy(SetAns);

end
```

Popgen function for single objective genetic algorithm optimization

```
function [ Pop ] = popgen(NoPop,NoVar,UBX,UBY)
%POPGEN Summary of this function goes here
%   Detailed explanation goes here
for i=1:NoVar
    if mod(i,2)==0
        Pop(:,i)=randi(UBY,[NoPop 1]);
    else
        Pop(:,i)=randi(UBX,[NoPop 1]);
    end
end
```

Scattered crossover function for single objective genetic algorithm optimization

```
%  Copyright (c) 2010-11, Mohammad Sayyafzadeh
%  All rights reserved.
%
%  Redistribution and use in source and binary forms, with or without
%  modification, are permitted provided that the following conditions are
%  met:
%
%     * Redistributions of source code must retain the above copyright
%       notice, this list of conditions and the following disclaimer.
%     * Redistributions in binary form must reproduce the above copyright
%       notice, this list of conditions and the following disclaimer in
%       the documentation and/or other materials provided with the
distribution
function popmut=Scattred(Pop,Fitness,pTour,pCross,pMut,UBX,UBY)
aa=size(Pop);
CM=randperm(aa(1));
for j=1:ceil(pCross*aa(1))
    % Tournoment
    NoSelectedPair=1;
    [ SelectedPop FitnessSelected ] = Tournoment(
Fitness,Pop,pTour,NoSelectedPair );
    %-----------------
    M=SelectedPop(1,:);
    F=SelectedPop(2,:);
```

```
    pCrossChor=0.5;
    popcross(j,:)=F;
    pp2=randperm(aa(2));
    popcross(j,pp2(1:pCrossChor*aa(1)))=M(pp2(1:pCrossChor*aa(1)));


end
%-----------------

%Mutation
popmut=Pop;
VV=randperm(aa(1));
OO=size(popcross);
popmut(VV(1:OO(1)),:)=popcross;
UU=randperm(aa(1));
for i=1:aa(1)
    RandMu=rand;
    if RandMu<pMut
        muGen=randi(aa(2),[1 1]);
        if mod(muGen,2)==0
            popmut(i,muGen)=randi(UBY,[1 1]);
        else
            popmut(i,muGen)=randi(UBX,[1 1]);
        end

    end


end
```

Appendix 2

Thermally Enhanced Gas Recovery and Production Optimization in Coal Bed Methane Reservoirs

Appendix 2

Paper title:

Combined Energy Recovery from Coal Seam Gas Reservoirs and Geothermal Resources (Simulation Study)

Alireza Salmachi, Manouchehr Haghighi, David Dixon, Peter Hart, and Ashley Jachmann

Australian School of Petroleum, the University of Adelaide

International Petroleum Technology Conference held in Bangkok, Thailand, 7-9 February 2012. IPTC 14847

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