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MASTER'S THESIS

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Abstract

In this project simulation of the Enhanced Coalbed Methane Recovery (ECBMR) is investigated. Two simulation models were built in Petroleum Experts and CMG (GEM) Software.

Prediction of the ECBMR is a complex process. It is affected by different factors, such as matrix shrinkage and swelling, the interaction of the injected gases with the seam, coalbed methane (CBM) and each other. A comprehensive investigation of ECBMR technics was achieved. Mechanisms of nitrogen (N_2) and carbon dioxide (CO_2) injection were studied and compared regarding the influence on recovery efficiency.

N_2 alternating CO_2 injection and CO_2 alternating N_2 injection simulations were performed in the project. Dependence on the sequence of the injection, injection gases ratio and frequency were addressed. Created models were used to analyse the production prediction of mixture injection of N_2 and CO_2 with different composition of injection mixture. Optimal regarding methane production recovery was discovered. Comparison of ECBMR injection variations was performed.

This project results could be helpful for further ECBM modelling studies.

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List of Abbreviations

AOF	Absolute Open Flow
BP	British Petroleum
CBM	Coalbed Methane
CCS	Carbon Capture and Storage
CMG	Computer Modelling Group
CO_2 – ECBMR	Enhanced Coalbed Methane Recovery with 100% Carbon Dioxide Injection
ECBMR	Enhanced Coalbed Methane Recovery
EPA	United States Environmental Protection Agency
ESP	Electrical Submersible Pump
GLR	Gas to Liquid Ratio
IPM	Integrated Production Modelling
IPR	Inflow Performance Relationship
MD	Measured Depth
MM	Million
N_2 – ECBMR	Enhanced Coalbed Methane Recovery with 100% Nitrogen Injection
OD	outer diameter
OGIP	Original gas in Place
PDP	Pump Discharge Pressure
PETEX	Petroleum Experts
PVT	Pressure – Volume – Temperature
RF	Recovery Factor
TVD	True Vertical Depth
UNFCCC	United Nations Framework Convention on Climate Change
VLP	Vertical Lift Performance

Chapter 1
Introduction
1.1 Background of the Problem

Coalbed Methane reservoir was considered in this work for the simulation and optimisation of the potential production via enhanced recovery method. Coalbed Methane Reservoirs are prospective part of the world energy production. They mostly consist of CH_4 (around 90%), and that is an especially important factor for the world which needs clean burning fuel (Seidle, 2011).

Enhanced coalbed methane recovery process is one if the promising enhancement techniques for the coalbed methane production. (Perera et al., 2015) There are different ways of performing ECBM recovery, and they consider injecting gases into the seam. CO_2 and N_2 are used for that purpose.

The first step for the CBM production is dewatering which allows methane to desorb from coal matrix and to release into the free phase in the pore space. After that period, CO_2 and N_2 injection can enhance the recovery. These gases have a different mechanism of interaction with the coal seam and in particular with the dual porosity system of the reservoir. Mechanisms should be compared regarding the influence on recovery and reservoir behaviour. Nitrogen alternating Carbon Dioxide case and injection of their mixture were also considered in the project. Possibilities of the simulating of that processes should be explored in this work. Coalbed reservoirs have specific and not like to the conventional gas reservoirs properties that make possible use them for CO_2 sequestration. Thus, the studying of the CO_2 behaviour in the seam is essential. (Godec, Koperna, & Gale, 2014)

In the project, the model of CBM reservoir is considered. IPM (PROSPER, MBAL and GAP) software by Petroleum Experts, GEM by CMG is used as a simulation environment. These programs are powerful and suitable tools for building a simulation model of production and injection systems. The aim of that study is to make a comprehensive knowledge of ECBM production and injection mechanisms by simulating these in IPM and CMG software.

1.2 Statement of the Problem

The purpose of this investigation is to explore the relationship between the type of injection and reservoir production properties. Latter will be predicted in a simulation environment. The nature of reservoir behaviour during ECBM recovery remains unclear, and this study intends to determine main parameters that affect that.

A key issue is to build a model of the CBM reservoir and simulate enhanced recovery via injection of CO_2, N_2 and their combination. However, this is limited by the fact that some of the coalbed methane recovery specific issues, such as micro and macro porosity system behaviour, swelling and shrinkage of coal matrix, could not be entirely simulated.

The response of CO_2 and N_2 injection to the seam to reach better methane recovery is not entirely understood. This case of study seeks to compare CO_2 and N_2 injection mechanisms and examine reservoir recovery resulting from implemented enhancement. Also, it is needed to find the optimal case regarding production recovery.

1.3 Methods and Approach

Several methods were used in the thesis to expand the objectives mentioned above.

Firstly, a literature survey helps to get a sufficient knowledge for understanding CBM reservoirs behaviour. Also, much of the current literature on coalbed reservoirs pays particular attention to the enhanced recovery. Thus far, several studies have confirmed the effectiveness of CO_2, and N_2 injections demonstrated that coalbed reservoirs could be used as potential CO_2 storages. (J. J. Gale & Freund, 2000; Godec et al., 2014) Simulated effects of matrix shrinkage and swelling during the injection based on the real CBM field and also hypothetical cases was investigated by A. Ibragim. (Ibrahim & Nasr – El – Din, 2015)

Overall, different studies helped to gather appropriate information about the project questions and take into consideration various ways of solving the problem.

Then, modelling of the process in 2 types of simulation environment: IPM and CMG. One advantage of the coalbed reservoir analysis in the simulator is that it makes possible to establish numerical models to find the optimum method for the CH_4 recovery optimisation in the typical coal seam. Another advantage of using computer simulations is that it allows to perform a comprehensive numerical modelling study and to investigate ways for the optimisation of the ECBM process (Perera et al., 2015).

Chapter 2

Literature Review

2.1 CBM worldwide

The role of natural gas in the picture of the global hydrocarbon reserves increased during the last decades. Natural gas is one of the largest energy suppliers since the reserves of other conventional hydrocarbons start to decline after reaching its maximum. (Z. Dong, Holditch, McVay, & Ayers, 2012) However, world energy demand is steadily increasing over the last 20 years, which made unconventional resources more valuable. This group of reserves requires much more technological solutions and complex techniques to reach high production rates. The right decision is to take a closer look at the unconventional resources like CBM methane reservoirs. (Z. Dong et al., 2012)

Coalbed methane production began on 1970's. It was performed during the production of coal mines in the United States as a safety technique for the degasification. Nowadays it becomes more economically valuables, but still, it is not enough profitable and successful. (World Energy Council, 2016)

On the other hand, methane has shown itself as a safety hazard: it presents in coal resources and could become very dangerous during underground coal mining. Only a few years ago coalbed methane potential was fully evaluated as probable energy resource (Rightmire, Kirr, & Eddy, 1984). United Nations Framework Convention on Climate Change (UNFCCC) has determined CH_4 as a greenhouse gas because its effect on the global warming is 21 times higher than the same parameter for the carbon dioxide. On the other hand, methane is recognised as an ecologically clean gas for its combustion components (CO_2 and H2O).

Subsequently, natural gas produced from the coal bed is environmentally safe. It consists mostly from the CH_4. Its production will not only reduce the amount of gas, leaked to the atmosphere while mining, but it will give the world another source of energy consumption. However, there is a huge resource base of CBM worldwide. (Standing Committee on Petoleum & Natural Gas, 2016)

Around 60 countries have valuable reserves of coal. A big number of them are attracted to the CH_4 production. (Halliburton, 2008) Once, CBM reservoirs exploration and further production are performed particularly in the Northern America plays, but nowadays it is considered worldwide. (Z. Dong, Holditch, Ayers, & Lee) In US coalbed methane production, cover about 10 % of the whole country's natural gas. (Roadifer & Moore) .

According to (Godec et al., 2014), global CBM recourses are estimated as 7000 Tcf of coalbed natural gas worldwide. Plays with the largest OGIP are situated in North America, Austral – Asia, and the Commonwealth of Independent States.

Table 1 – Coalbed Methane Recourses y Country/Region

Country	*CBM Gas -In - Place, Tcf*	*CBM recoverable, Tcf*
United States	1746	170
Russian Federation	1682	200
China	1229	195
Canada	550	184
Indonesia	453	68
Middle East & Africa	417	63
Ukraine	170	25
Australia	152	34
Germany	106	16
United Kingdom	102	15
India	80	20
South & Central America	76	11
Turkey	51	10
Kazakhstan	50	10
Poland	50	5
Total World*	7011	1030

** total value also includes Mexico, Brazil, Colombia, Venezuela, Czech Republic and Hungary. (Godec et al., 2014)*

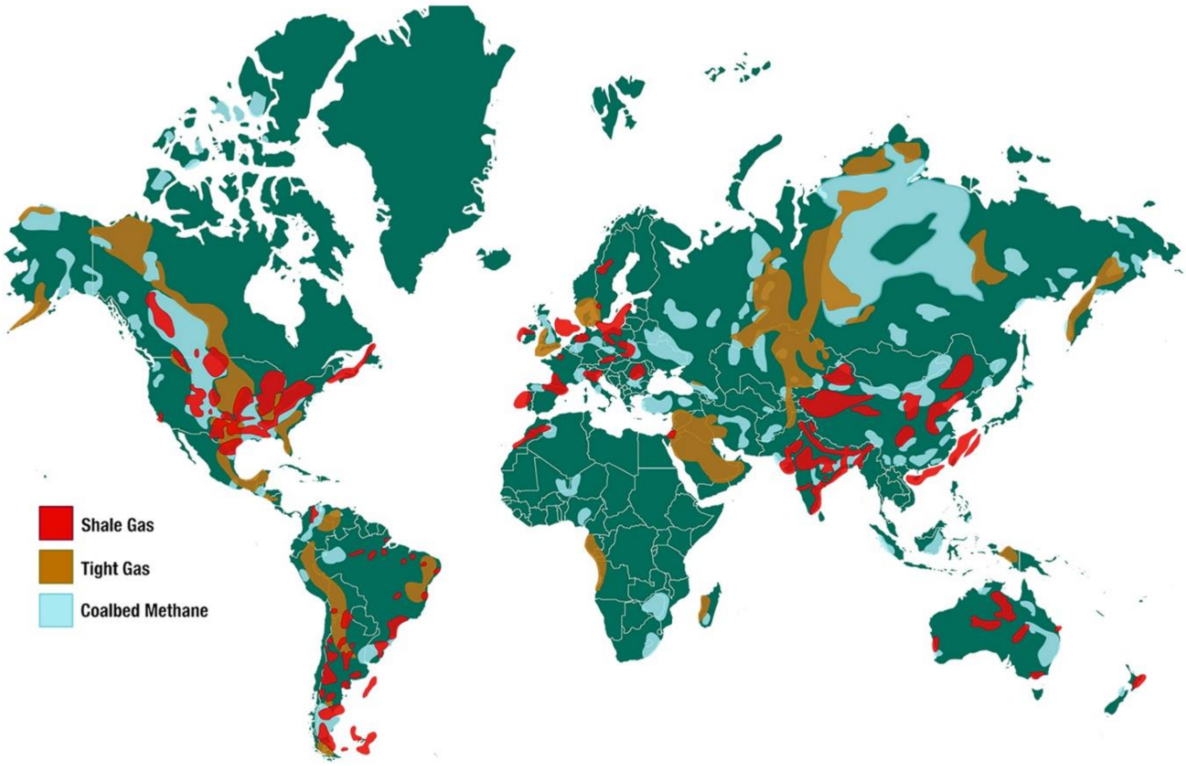

Figure 1 – Worldwide distribution of Coalbed Methane Resources. (Radialdrilling, 2017)

Figure 1 shows the distribution of the CBM resources in the world. CBM has an appealing potential as a clean fuel of the future for the countries where coal might be the only source of natural energy, e.g. Eastern Europe. Much potential has CBM places in Poland, Australia, Canada, the Peoples Republic of China, Great Britain, Germany, Zimbabwe, and Russia.(Halliburton, 2008). US, Canada, and Australia, China, India also have CBM production operations in play. (World Energy Council, 2016)

However, in Asia, Eastern Europe and Latin America the perspective and the economics of the CBM reservoir exploration is not entirely understood yet, or there is an abundant amount of conventional plays. (Z. Dong et al., 2012) The rapid growth of the economies all over the world leads to the corresponding increase in the energy sources demand. For such countries as China, that means that coal demand will become greater. Latter includes increasing the mining depth (over 1000 m) which could provoke different risks: either economic or safety issues, risks of coal and gas explosion strengthens. On the contrary, more coal production on that depth leads to the greater amount of methane emissions thus inducing global warming potential. (Fang, Li, & Wang, 2013)

Coal reserves in Indonesia have a high – quality coil and respectively high perspective for development. Australia is famous for it is in use of produced CBM for the natural gas liquefaction and export. Likelihood, technical improvements will not stop, and the financial aspect of the process would allow CBM development to expand. (World Energy Council, 2016)

Summarising the previous statements, use of coalbed natural gas as a potential energy source could provide such advantages as the following (Halliburton, 2008):

- Production of the clean – burning fuel;
- Serious expansion of the natural gas reserves;
- Decrease of the safety risks during coal mining;
- Reduce methane emissions to the atmosphere;
- Mines, which were too deep to safe explorations, become available for the gas production.

The valuable amount of methane (CH_4) generates in the coal seams during the geological process of coal creation. One tonne of coal could contain around 200 m3 of CH_4 which was generated during coal formation. This gas is called coalbed methane. Coalbed natural gas could also contain small quantities CO_2 and N_2. A significant part of that methane was released with time. However, around 25 m3 CH_4 per tonne of coal could be found in the undamaged coal formations. (J. J. Gale & Freund, 2000) Coal burying depth and its rank may be influenced by the amount of the contained in the seam methane. The formation of high rank of coals took place at the higher pressure and temperature conditions and resulted in the higher amount of generated gas. The small depth of the seam could lead to the gas migration and leak up to the surface. Methane occurs the close to liquid form, so it enables it to fill the coal surface (matrix) due to adsorption process. Only 1 gramme of coal could have a surface area of 20 – 200 m2. (J. J. Gale & Freund, 2000)

Several of the major CBM reservoirs are described below. These reservoir's characteristics were used as a data source in this thesis.

- Black Warrior, San Juan

San Juan Basin is situated in New Mexico and Colorado of United States It covers around 6700 square meters. San Juan Basin is one of the most operating areas of coalbed methane production in the United States. (Ayers Jr & Kaiser, 1994) Estimated recourses are to be between 43 – 49 Tcf at a depth of 400 to 4200 ft. The Fruitland Formation is in the centre of this research because it is dominant and one of the most important in the country coal – bearing formations of the San Juan Basin. It is situated in the North – Central part of the field and occurs to be the most developed formation of the basin. This formation is considered as Upper Cretaceous geological formation.

(Kaiser & Ayers Jr, 1994). Most coals of the San Juan basin are originally 100% water saturated and have a porosity of 1 % (Cox, Stevens, Hill, & McBane). The total original gas in place (OGIP) of all 12 seams in the Fruitland Formation is around 50Tscf. As (Ibrahim & Nasr – El – Din, 2015) notice, at the beginning of 2013 the remaining OGIP amount to 7.2 Tcf. This formation provided around 99.2% of the total natural gas of the San Juan Basin (Z. Dong, Holditch, Ayers, & Lee). The average thickness of the coal deposits there is approximately 40 ft while maximum value is around 70 ft. Permeability also varies from 5 to 60 mD in the different parts of the reservoir. According to (Ibrahim & Nasr – El – Din, 2015), gas content is commonly around 300 SCF/tonne.

- Black Warrior Basin – Pottsville Formation

Black Warrior Basin is situated in Alabama and Mississippi of United States is also used as an example for the further project model. Natural gas is mostly produced from the Lower to Middle Pennsylvanian Upper Pottsville formation (Ibrahim & Nasr – El – Din, 2015). Coalbed natural gas is commonly produced here on the depth lower than 3000 ft. Two groups within the field are investigated: Mary Lee and Black Creek groups. Mary Lee and Blue Creek groups have good coal quality and respectively good gas resources. That establishes production interest to these groups. (Karacan, 2013). Degasification process started in 1971, and vertical wellbores were used for that purpose. The reservoir has an effective area of 2050 acres. Average OGIP in the Black Creek group is equal to 1.52 – 1.23 MMscf/acre. Also, the coal of that group has high gas adsorption potential. It was described by the values characterising the Langmuir Isotherm: Langmuir Volume and Langmuir Pressure which are equal to 567 SCF/tonne and 644 psia respectively.

2.2 General CBM properties

Coalbed methane reservoirs have a certain number of characteristics that make it behaviour and production alike conventional reservoir: reservoir properties, gas storage mechanisms, the gas – transport phenomenon, water disposal.

First of all, the main difference is in the methane storage mechanism. While in common reservoirs gas is held in the pore spaces, here gas is stored in the adsorbed condition. (Fekete Associates, 2006)

Most coals two forms of porosity or dual porosity. Microporosity and microporosity represent it. Average matrix porosity less than 1%, (Gunter, Gentzis, Rottenfusser, & Richardson, 1997) Natural fractures (cleats or macropores) creates the value of the fracture porosity. Matrix porosity is determined as a microporosity. Therefore, gas could be stored in the reservoir in 3 possible ways:

- In adsorbed condition: gas molecules are adsorbed on the coal matrix surface;
- As a free gas: in the micropores and macropores;
- As dissolved in the water gas.

The largest amount of gas is commonly stores in the adsorbed state. On the coal surface of 1 tonne of rock around 2000 tcf of CH_4 could be adsorbed. Dissolved or free gas is held in a relatively small share of total fluid volume. Despite the high values of cleat porosity (up to 15%) effective porosity in the seam is minimal and is generally around 1 %. (Warren & Root)

Whereas, in conventional reservoir gas expands as pressure decreases in CBM reservoir pressure should reach some threshold value to initiate the desorption. In under saturated coal reservoirs, initial reservoir pressure could be higher that the desorption pressure. (figure) Cleat system is initially saturated with water. (Sloss, 2015) This water without any gas would be produced during the first production period until the pressure reaches the desorption point. More under – saturated is reservoir longer this period would be. (Morad, Mireault, & Dean, 2008)

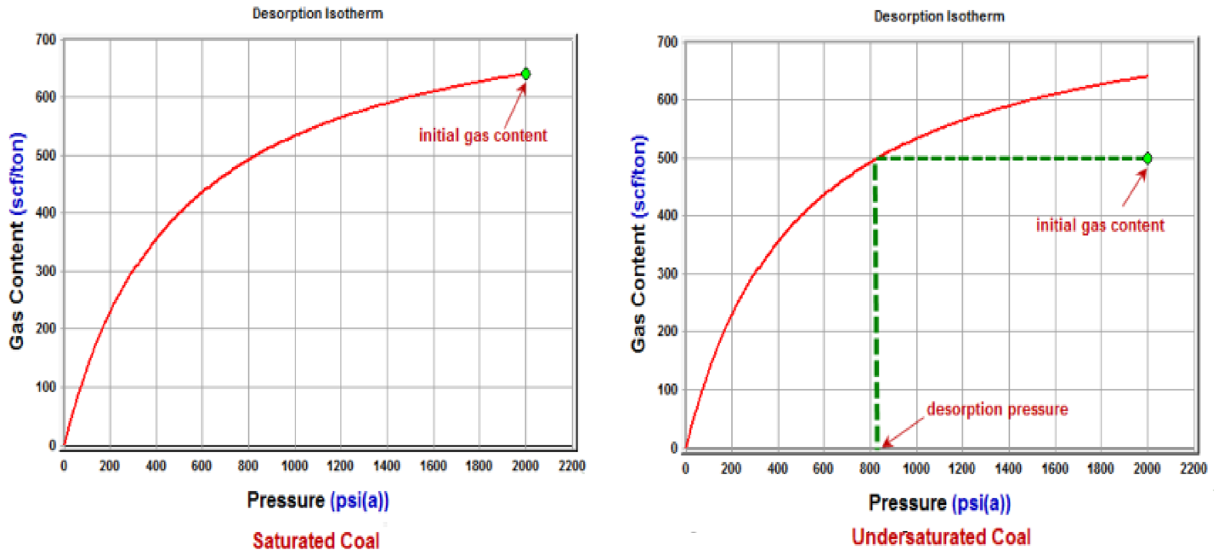

Figure 2 – Langmuir isotherms for saturated and undersaturated coal (Fekete Associates, 2014)

Gas flow in the reservoir follows defined mechanism (Figure 2) Firstly, gas desorbs from the coal surface inside the micropores and then due to the diffusion gas spreads to the macropores (cleats). Then gas goes by Darcy flow through the fracture network to the wellbore. (Sloss, 2015)

The release of the methane from the seam also depends on the additional factors such as low reservoir permeability: 0.1 – 10 mD; and high compressibility. Close to each other multiple production wells patterns is suggested to decrease the effect of permeability.(Sloss, 2015)

Coal rank determines what type of well orientation could be used in one or another CBM case. Lower rank makes production by vertical wells more available. Horizontal wells are suggested for more shrunk coalbed seams with high coal rank (Godec et al., 2014)

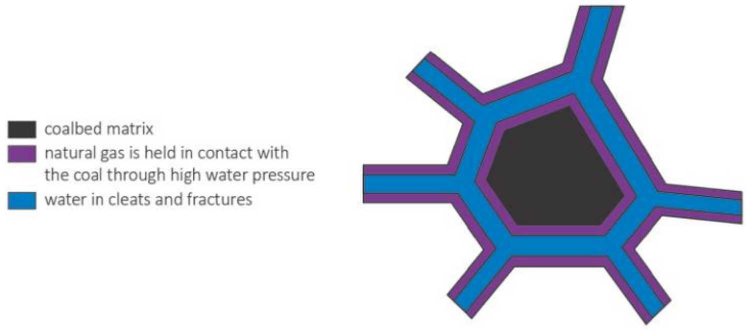

Figure 3 – Coalbed matrix illustrating gas surrounding the coal bound by water and rock (Sloss, 2015)

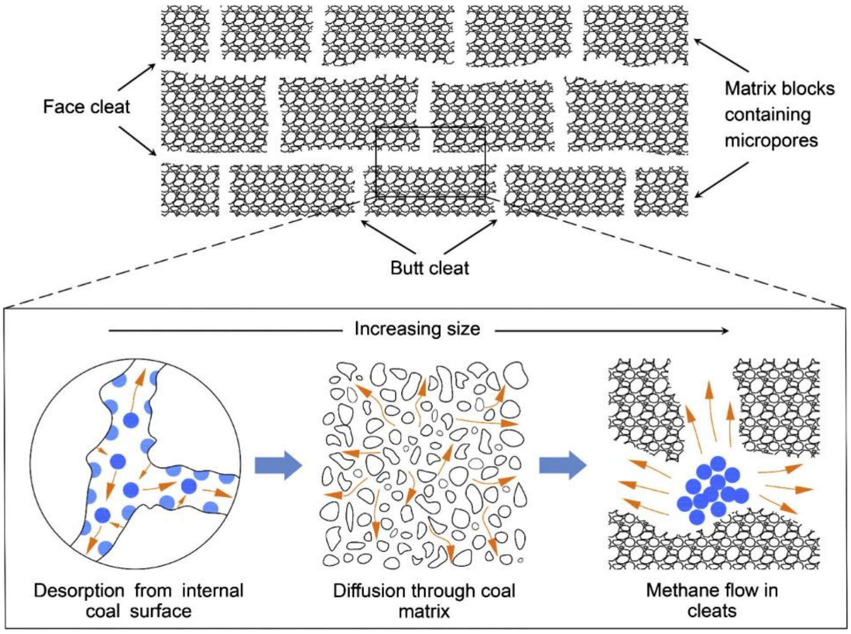

Figure 4 – Desorption and diffusion processes in coalbed seam (J. Dong et al., 2017)

Diffusion of gas through the micropores could be estimated by Fick's law, which is applied to equation 1.

$$\frac{D\delta}{r^2\delta r}\left(\frac{r^2c}{r}\right)=\frac{\delta c}{\delta t} \tag{1}$$

Where c is the gas concentration, t is the time, D is effective diffusion coefficient, r is the radial distance from the centre of the particle. The diffusion coefficient for methane in coal is a dependent on temperature, pressure, pore length, pore diameter, and water content. (*Coalbed Methane: Principles and Practices*, 2008)

2.2.1 Gas transport mechanism

Adsorption is the major mechanism of methane storage in the coal seam. Langmuir Isotherm describes the desorption characteristics of the coal. It represents the relationship between pressure value and the content of adsorbed gas at moisture conditions and constant temperature. (Al – Jubori et al., 2009)

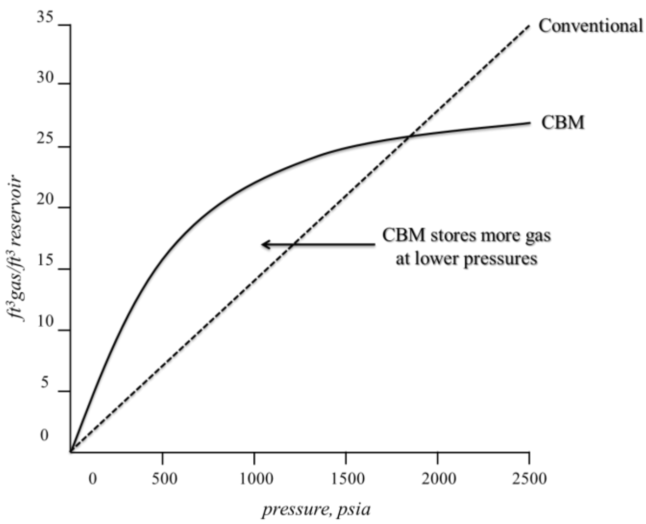

Figure 5 – Langmuir isotherm for CBM and conventional reservoir (Fekete Associates, 2006)

Langmuir Isotherm for the single component is described by equation 2:

$$V = \frac{V_L bp}{1 + bp}; \quad (2)$$

Where V_L is Langmuir Volume

b – Langmuir Pressure constant, $b = \frac{1}{p_L}$;

p – Reservoir pressure.

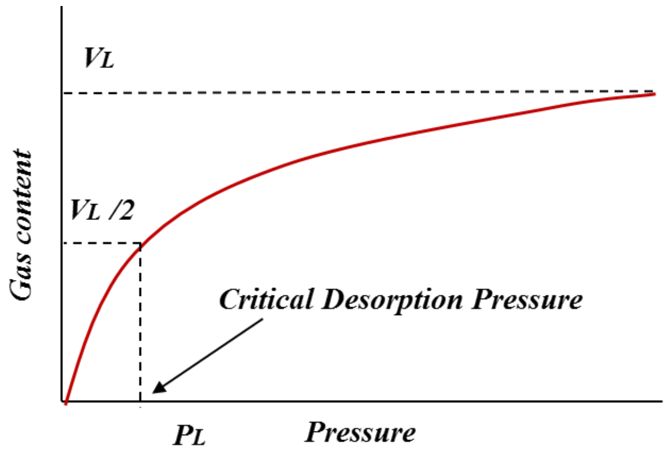

Figure 6 – Langmuir isotherm parameters (Fekete Associates, 2014)

Graphically these parameters are represented in Figure 6. For modelling of multi – componential adsorption of gases to the coal seam, Extended Langmuir method is used. (Clarkson, Jordan, Gierhart, & Seidle) The equation represents it:

$$V_i = \frac{V_{Li} b_i p y_i}{1 + \sum_j b_j \, p y_i}; \quad (3)$$

Where V_i is the amount of component (i) in adsorbed condition;

V_{Li} and b_i are Langmuir constants for component (i);

y_i – (i) component mole fraction in free gas phase (in equilibrium with adsorbed gas)

The total amount of adsorbed gas is estimated by equation 3 (Clarkson et al.).

$$V_T = \sum_I \left(\frac{V_{Li} b_i p y_i}{1 + \sum_j b_j \, p y_i}\right); \quad (4)$$

The shape of the Langmuir isotherms shows that coalbed methane could store more gas at lower reservoir pressures than the conventional reservoir rock.

Original gas in place could be estimated as the sum of the gas adsorbed in the coal matrix (Morad et al., 2008) free gas dissolved in the water. The equation used for that is represented below:

$$OGIP = [A \cdot h \cdot \rho_b \cdot GC_i] + \left[\frac{A \cdot h \cdot \varphi_i (1 - S_{wi})}{B_{gi}}\right] \quad (5)$$

Where: A – drainage area; h – net pay; ρ_b – bulk density; GC_i – initial Gas Content; φ_i – porosity; S_{wi} – initial water saturation; B_{gi} – initial formation volume factor.

There are three typical stages of coalbed methane wells production (Figure 7).

1. Dewatering stage. CBM wells initially produce water. Then with water production, gas desorbs from the seam and is added to the production fluid. Gas rates are small but are increasing. The pressure depression accelerates gas desorption. Water rates are high and decreasing during that period (Godec et al., 2014).
2. Stable production stage. Gas production reaches its maximum values while water production levels off. That stage commonly takes place after around ten months of the initial production. Gas production rates decrease very slowly during that phase.
3. Decline stage. Water rates are not significant in this period, and gas rates decline until the moment when production becomes uneconomical. (Morad et al., 2008)

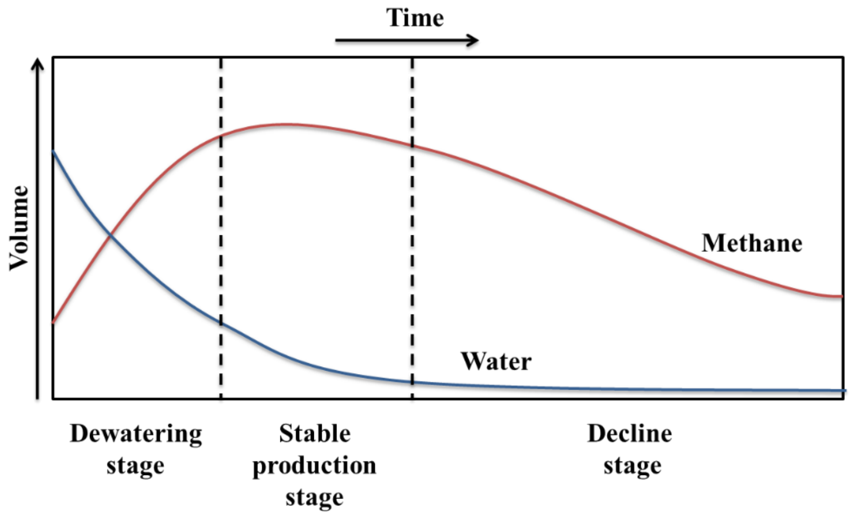

Figure 7 – CBM reservoir production stages(Merriam, Brady, & Newell, 2012)

In general, possible recovery from the coalbed methane reservoirs is estimated around 50%. Gas is produced mostly by the seam dewatering (Godec et al., 2014) The stabilised exponential decline is described by equation 5

$$q = q_i \cdot e^{-Dt} \qquad (6)$$

where q – production rate at time t, vol/unit time, q_i – producing rate at time 0, vol/unit time, D – nominal exponential decline rate, 1/time, t = time, e = base of natural logarithms (2.718). (Merriam et al., 2012)

CBM production potentiality is defined by several characteristics that are changing from reservoir to reservoir. It could be fracture permeability, coal maturation and gas migration aspects. Well completion options also effect on the production behaviour as well as hydrostatic pressure and coal distribution. Geological structures and confined faults have a tendency to influence on the natural fracture pattern by expanding it. Therefore, increasing possible ways for methane production. The processes and technologies are still in the development phase. (Godec et al.)

Matrix Shrinkage: Gas is stored in the porous structure of the coalbed matrix. As gas is desorbed from the coal, the pressure exerted by the gas in these pores decreases. That causes the matrix volume to reduce in size. Moreover, this reduction makes cleats wider and thus to permeability increases. (Fekete Associates, 2006)

2.3 Enhanced CBMR

The gas pressure restrains CBM reservoirs recovery and accordingly, not all amount of accessible gas could be recovered. By injection of different gas into the coalbed, the remained methane could be released. Most commonly used for that purpose gases are N_2, CO_2, flue gas or the combination of the previous ones. (Sloss, 2015)

This technology includes CO_2 and N_2 injection to the coalbed seam which allows to significantly induce fields recovery without lowering the pressure until the critical values. It is estimated that ECBMR technology allows increasing production rates up to 90% of the original recovery value. Although this result is very impressive, it is mostly based on the theoretical studies. (Fang et al., 2013)

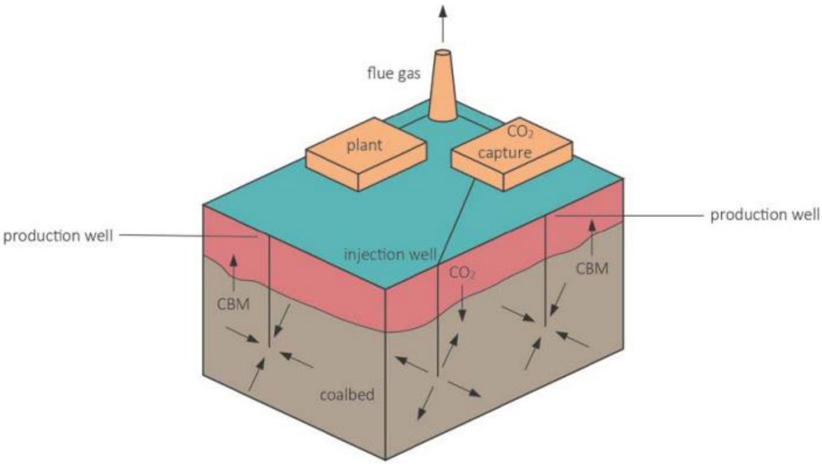

Figure 8 – Principle scheme of ECBMR (Zheng & Xu, 2014)

The general principle of ECBMR is shown on the figure: chosen gas composition is injected into the reservoir by an injection well. Injection gas distributes in the seam and resulting in the methane liberation. Different gases have different affinities to adsorb onto the solid surface such as the coal seams. The Figure shows the Langmuir Isotherms for various gases. It relates the reservoir pressure, gas content and describes how easily each of these gases desorbs or adsorb from the coal surface.

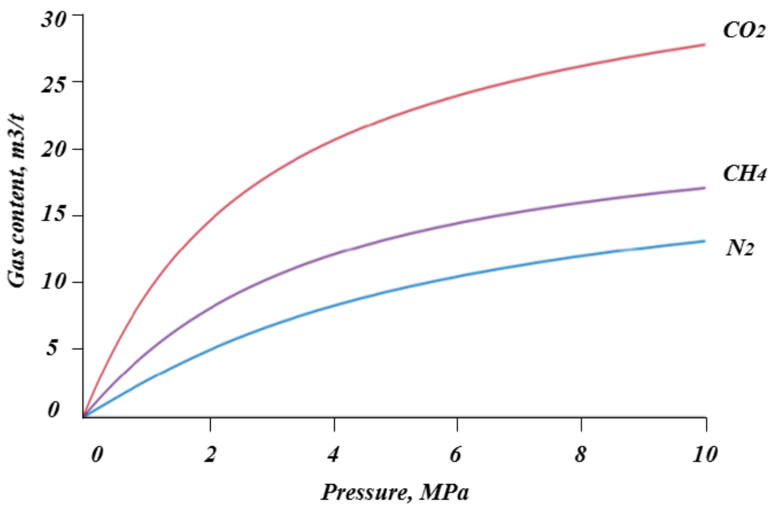

Figure 9 – Measured CH_4 and estimated N_2 and CO_2 Langmuir isotherms (Airth, Scotland). (Sinayuc et al.)

2.4 Injection gases

2.4.1 CO_2 injection

When CO_2 is injected it interacts with the coal seam: gas goes through the fracture system and by diffusion gets into the coal matrix micropores. The affinity of CO_2 to adsorb in the coal is much greater than affinity if CH_4. Thus, CO_2 adsorbs to the coal surface as a substitute for CH_4. Consequently, injected CO_2 replaces CH_4 from micropores. (Al – Jubori et al., 2009), (White et al., 2005)

The concept of Enhanced CBM Recovery supposed by Every and Dell'ossoin 1972 touches on a potential of CO_2 sequestration. They discovered that production of methane would increase dramatically if injected CO_2 stream at ambient temperature conditions is passing the coal seam. (White et al., 2005)

From the Figure 9, it could be noticed than CO_2 adsorption to the coal is almost twice higher than CH_4. After the implementation of the CO_2 injection coal matrix could start swelling as CH_4 is displaced by the greater quantities of CO_2. The swelling effect results in a reduction of the coal permeability and injectivity for further CO_2 injection or capture. (Sloss, 2015) Horizontal drilling and rock fracturing technologies could solve that problem and improve gas. However, this is not suitable for the ECBMR projects that contain gas storage because of the possibility cap rock deformation the and potential leaks. (Godec et al., 2014 2014).

Gas flow in the coal begins in the fracture network. Injected CO_2 goes through the cleats and then diffuse from them to the coalbed surface thus replacing adsorbed CH_4. Coal permeability in coal could also change because of the pressure changes in the formation during the depletion process. 2 main parameters affect on that permeability – pressure relationship: Coal compressibility, Matrix shrinkage. (Sloss, 2015)

Coal permeability changes with the change of adsorbed gas amount. When CH_4 desorbs and is them leaves the seam, permeability value increases. With CO_2 adsorption, it starts to decrease. This process could be defined as matrix shrinkage and swelling. Complicated interaction of flow in the fracture system, caused by the gases displacement, changes in permeability, diffusion and adsorption characteristics. (Orr, 2004)

Rock compressibility can play a considerable role in the well deliverability potential. When pressure reduces, fractures compresses by the overburden and permeability in the seam decreases. A schematic description of this behaviour is shown in Figure 10.

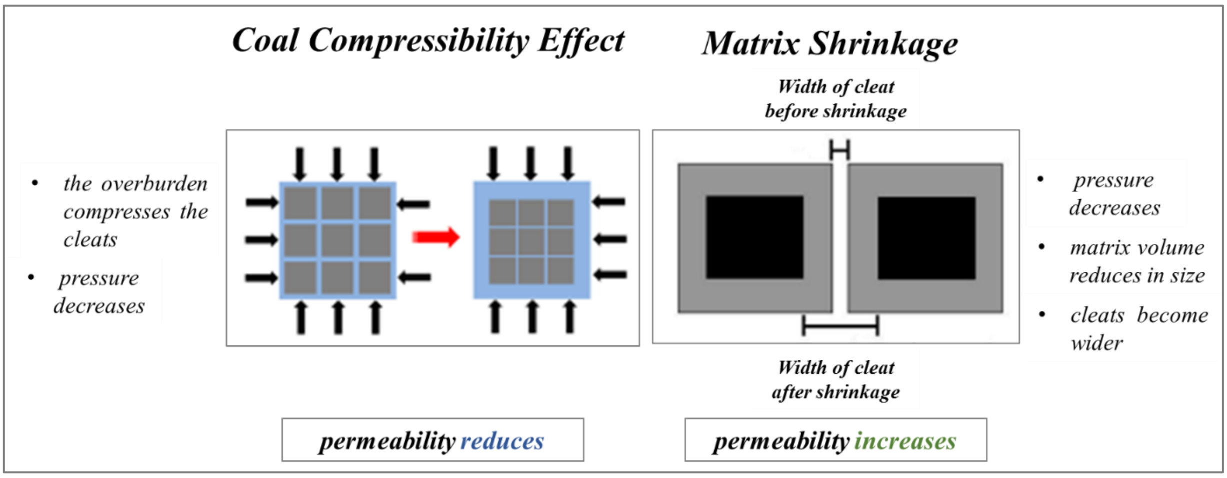

Figure 10 – Permeability – pressure relationship (Fekete Associates, 2014)

Processes that take place around production and injection wells during the implementation of ECBM recovery technique are diverse. Effective permeability controls the flow of gas and water in the seam. CO_2 injection pressurises fractures that are located nearby the injection well thus increasing fracture porosity. Consequently, water amount remains the same relatively to the increased pore space volume. Thus, water saturation in the fractures decreases as a relative permeability to water. Therefore, relative permeability to gas increases. CO_2 injection period causes not only swelling but also ballooning effects. (Mavor, Close, & McBane) Swelling reduces the seam porosity while the water saturation enlarged, in sequence decreasing the relative permeability to gas and increasing the relative permeability to water. This permeability changes could be overcome by ballooning effect. (Sloss, 2015) Further CO_2 injection and decreased effective permeability to gas could origin the injection pressure to induce up until ballooning effects affect both swelling and relative permeability effects. Therefore, that allows continuing injection process. (Mavor et al.)

2.4.2 N_2 injection

Gas injected into coal for ECBM recovery is an advanced technique which appeared in the early 1990s. (White et al., 2005). The mechanism used in the N_2 injection is to some extent similar to inert gas injection because nitrogen has less adsorbing affinity than methane. Nitrogen – enhanced coalbed methane recovery (N_2 – ECBMR) decreases the partial pressure of methane in the seam, thus helping methane to desorb without depressing the reservoir pressure. (Sinayuc et al., 2011).

Injection of N_2 can male less reduced permeability effect caused by the CO_2 injection, and it can improve well injectivity (Fang et al., 2013). That type of ECBM diminishes the partial pressure of CH_4 within the seam upholding the total pressure and thus stimulating gas production from the well. N_2 releases the CH_4 through gas extrusion and sorption replacement. Approximately 25–50% of CH_4 storage capacity could be replaced with N_2 – ECBMR (US EPA, 2015).

2.4.3 Complex injection

To benefit more from the ECBMR CO_2 and N_2 can be used in a complex injection. Figure 11 shows the principle scheme of N_2 alternating CO_2. Preliminary use of N_2 is to lower the partial pressure and increase methane desorption. After some time, the N_2 will breakthrough to the methane production, which is undesirable. (*Potential for enhanced coalbed methane recovery*, 2015) Applying of CO_2 injection on that step can continue CH_4 recovery by the competitive adsorption of the CO_2. This will stimulate production until the CO_2 breakthrough.(J. Gale & Freund, 2001),

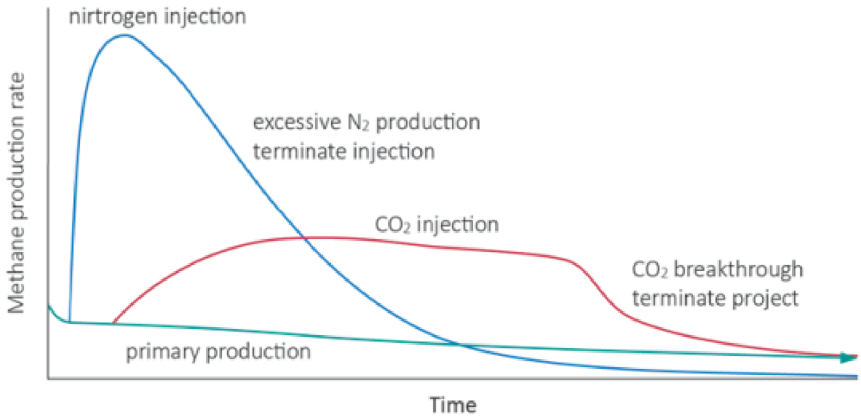

Figure 11 – Indicative methane production profiles with N_2 *and* CO_2 *injection(J. Gale & Freund, 2001).*

Suggested by Fang CO_2 – alternating – N_2 injection could be considered as a likely way of enhanced recovery. Economics of that method would depend on operational limitations, gas treatment costs and whether CCS is a principal goal of the project. (Fang Z, 2013)

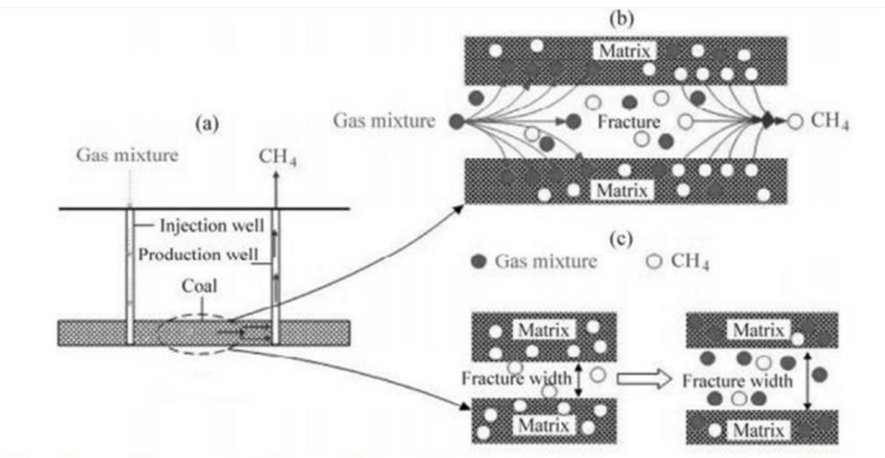

Figure 12 – Schematic diagram of ECBM for enhanced CBM recovery: a) well pattern; b) CH_4 *displacement process; c) permeability and injectivity enhancement. (Fang et al., 2013)*

CO_2 and N_2 could be used in a mixture injection for ECBMR Injected gas composition effects on the production properties. Several studies were performed to investigate that topic. Different gas mixture cases contained N_2 (from 80 to 20 %), and CO_2 (from 20 to 80) were suggested by Perera (Perera et al., 2015). It is essential to find the appropriate composition to reduce the risks connected to the ECBMR and get high recovery values. 40%N_2 +60%CO_2 showed the best results in author's investigation. The author performs simulations using COMET 3 tool to optimise enhanced CBM recovery.

(Chaback, Yee, Volz, Seidle, & Puri, 1996) In his study performed a simulation of enhanced gas recovery. He used N_2 and CO_2 as an injected fluid and also simulated the effect of dry flue gas composition (85% of N_2 and 15% of CO_2) of injected gas. CO_2 – injection pilot project was made by BP – Amoco in San Juan Basin from the Fruitland Formation in Colorado in 1993 (Gunter et al., 1997) (White et al., 2005). Other experiment contained flue gas stream produced by the diesel engine (83% N_2 and 12% CO_2). It was used as an injected fluid for the San Juan coal. In 1996 CO_2 – ECBM was done in the Mexican part of San Juan Basin by Burlington Resources (Stevens & Kuuskraa, 2000). Thus, modelling of ECBMR is essential to ascertain the optimal parameters that allow reaching maximum production efficiency of the seam

2.5 Carbon Capture and Storage

The concentration of carbon dioxide in the air is increasing from year to year. CO_2 emissions effect on the global warming. They cause substantial problems of the modern world. One of the options of reducing its influence on the atmosphere quality is sequestration of CO_2 in the unmined Coalbed Methane Seam. (White et al., 2005) Carbon capture and storage (CCS) could exert a positive effect on the environment. It could reduce around 19% of total gas emissions. Adsorption is the major mechanism allowing CO_2 to be stored in the coal seam.(Zheng & Xu, 2014) Captured on the special facilities CO_2 might be used for the enhanced recovery or the ecological issues. Coalbed methane reservoirs are considered as a carbon storage and sequestration. (Sloss, 2015) The US Environmental Protection Agency submitted that total CH_4 emissions could be reduced by half if ECBM technology shows at least 50% of its efficiency. (Sinayuc et al., 2011) CO_2 – ECBMR and sequestration project was performed in the Dutch coal in Netherlands.

In the 1990s the Hypothesis of enhanced coalbed recovery and potential CO_2 sequestration was investigated by Puri and Lee and MacDonald of Alberta Energy (White et al., 2005), (Godec et al., 2014). After that, during the exploitation of the Alberta coalbed methane reservoir, it was proved that discovered that during the ECBMR using CO_2 injection, part of the injected fluid was left in the seam in the adsorbed phase. (Gunter et al., 1997) Mechanism of displacement is that one molecule of methane is displaced by two molecules of CO_2. (Gunter et al., 1997)

2.6 CBM, CCS and ECBMR Modelling

Various investigations have been completed in that field of study. There are different types of models used in ECBM such as multicomponent adsorption theory, flow theory, and diffusion theory. (Sloss, 2015)

Commercial simulation environments are accessible for ECBM investigations: including IPM, GEM (CMG), ECLIPSE, SIMED II, COMET2 as well as non – commercial simulators for instance GCOMP. Z. Dong et. al. showed approximate estimation and distribution of the CBM recoverable resources worldwide. A simulation model was implemented to assist in the estimation global technically recourses in the U.S. – 1500 Tcf and a technical recovery factor of 36% (Z. Dong et al.) (Mora & Wattenbarger, 2009) were comparing the computation methods for CBM performance. Authors show reservoir predictions results performed in such simulation environments as PRODECY, F.A.S.T. CBM, GEM and ECLIPSE. There are differences between simulation results in different numerical simulators and programs. Some of them do not include diffusion, predicted production performance could also be distinctive. Accurate estimation of OGIP and reservoir characteristics such as fracture porosity and permeability is essential for the future production (Mavor et al.). A model combining laboratory tests and simulation was made to determine coal seam deliverability characteristics as a function of well pressure and time.

(Karacan, 2013) investigated simulation model of coalbed seam analysing production and degasification well data. That method allows to estimate OGIP and cumulative production of coalbed methane before mining and is useful for clarifying the uncertainness connected with that issue.(Özgen Karacan, 2013)

Field experience is moderate, but there are several; projects that are tested or going to be implemented in U.S., Canada, Poland, Australia and Japan. CO_2 – ECBMR is carried out at Alison unit in the San Juan Basin. (Orr, 2004)

(Sinayuc et al., 2011) presented an investigation of hypothetical and efficient CBM recovery with stimulating gas injection by vertical wells. Airth field in Central Scotland was considered and a potential CCS and simulated. 10 and 40 years period characteristics prediction showed that the most effective composition for the ECBMR is flue gas composition. Also, total CCS capacity increases twice for flue gas and other mixed gas composition injections in 4o years simulation period. An accomplished study by (Thararoop, Karpyn, & Ertekin, 2012) shows simulation results for the dual – porosity and dual – permeability coal seam. CO_2 – ECBMR and flue gas as injection fluid allows getting satisfactory production characteristics. Recently, Composite Energy Ltd has done effective horizontal well drilling for ECBM in Scotland (Clackmannan coalfield) Research was performed an investigation. Authors simulated coalfield production and accomplished the research about factors that influence on the production effectiveness: composition of injection fluid, well orientation, the number of injection wells, permeability heterogeneity. Simulated CCS with ECBMR was also simulated, and storage capacities were estimated. (Sinayuc et al., 2011) Variation of coal seam properties has a significant influence on the enhanced recovery process as well as the injected gas composition. Also, number and pattern of production and injection wells play significant role in the CBM production.(Perera et al., 2015)

(White et al., 2005) In their review showed that CO_2 – ECBM and sequestration are in the developing stage. CO_2 sequestration projects are realistic and can have good results of storing the greenhouse gas in the geosphere. (Ozdemir, 2009) predicted CBM production with performed CO_2 injection. Water removal, degasification and then CO_2 sequestration option are difficult to simulate. Interaction of seam water and injected CO_2 reduces the CCS capacity of coalbed. Shrinkage and swelling coal matrix effect affect the CH_4 production and injection characteristics.

(Ibrahim & Nasr – El – Din, 2015) in their CBM simulations used both theoretical cases related to the real numerical solutions and also reservoir properties from San Juan and Black Warrior Basins. It allows to perform history match and predict primary production of CBM reservoir in CMG – GEM software. Hypothetical cases were assumed to obtain reservoir parameters and predict future performance from history matching mode. Results showed significant matrix shrinkage effect that is recommended to be inserted in the reservoir production estimation.

Modelling of CBM reservoir enhanced recovery allows predicting the difficulties that are connected with the coalbed reservoir performance. Investigations, sensitivity analysis and calculations carried in the different works summarise the limitations connected with CBM production activity. Therefore, studies allow to understand better the complicated processes and to optimise the future production.

Chapter 3
Methodology
3.1 Software description

Two types of software environment are used to reach the desirable results.

3.1.1 Petroleum Experts (Petex, IPM) (Petroleum Experts, 2017)

Programs used in his thesis from IPM Suite are PROSPER, MBAL and GAP

Programs used in this thesis from IPM Suite are PROSPER, MBAL and GAP

- PROSPER is Petex a tool allowing to design and model the various types of well configuration. Well performance and optimisation are important parameters that could be investigated with the support of the program. Different types of reservoirs models from conventional oil and gas seams to the unconventional shale and CBM reservoirs could be assisted with PROSPER. It allows building dependable and persistent well profiles and infrastructures considering highly detailed technical characterisation and complex calculations. This user – friendly software environment allows creating a system of production and injection wells, related to the real data by matching of to the hypothetically made production scenarios. This tool could be used to predict future reservoir behaviour by estimation of reservoir potential characteristics. (Petroleum Experts, 2017)
- While the previous tool is responsible for the design of the well, MBAL (Material Balance) is used to perform the analytical studying of the reservoir. With its assistance, it is possible to define the reservoir characteristics, to determine reservoir drive mechanism and also to calculate hydrocarbon volumes. MBAL consists of different engineering tools: for classical and modern reservoir engineering simulations, for tight gas and for convenient reservoirs. Material balance calculations allow building Pressure – Volume – Temperature (PVT) models for the different type of fluid. (Petroleum Experts, 2017)
- General Allocation Program (GAP) is an optimisation program that is used for the reservoir production prediction and performance of different activities and scenarios of reservoir behaviour. Models made previously in the PROSPER and MBAL could be gathered in the GAP complex field production model for the further optimisation. Different kinds of production and injection systems could be modelled with the help of GAP. Production system generally consists of such elements as wells, and connections, manifolds, separators and pipelines. The multiphase well flow and surface network could be analysed in GAP.

3.1.2 Computer Modelling Group (CMG)

Computer modelling group software is aimed to perform reservoir simulations, to explore and investigate new recovery methods. According to the creators of this software, it will help to face modern technological barriers and find a different kind of inventive solutions for them to reach desirable goals. (Computer modelling group, 2017)

CMG group consists of several modelling tools: CMOST, IMEX, GEM, STARS, COFLOW, BUILDER, RESULTS and WINPROP. Three tools from the suite were used in this thesis:

- BUILDER. It is a pre – processing tool that allows building the model of the investigated reservoir itself. The builder has an intuitive interface that provides a possibility to perform clear data input. It allows to design reservoir structure and to create 3D geomodels using contour maps etc. This tool prepares the model for all following simulators (IMEX, GEM). Thus it can build the model of conventional and also unconventional reservoirs such as shale gas, heavy oil or coalbed reservoirs. Wells modelling is also included to the BUILDER's possibilities: production and injection patterns with advanced wellbore modelling could be made using this tool. When the model is ready it could be easily exported; data output also could be selected in BUILDER. .(Computer modelling group, 2017)
- GEM is the next step of the simulation. It is the equation of state – based tool for compositional, chemical and unconventional reservoir modelling.(Computer modelling group, 2017) It could model a 3 – phase fluid flow and define complex phase behaviour. It was used in this project because it allows to model matrix – to – fracture system of the Coalbed methane reservoirs. GEM is functional reservoir simulator for modelling primary and enhanced recovery processes, for different types of unconventional reservoirs.
- RESULTS is a tool that helps to present simulated in 2 previously mentioned programs results. The main aim of that tool is to visualise the processes that take place during the simulation of the studied reservoir and to represent them in the most understandable way: for instance plots, grouped data or 3D visualisation. .(Computer modelling group, 2017)

3.2 Data, reservoir description

Reservoir data is collected from the literature: papers describing simulation experiments and geological characteristics of coalbed reservoirs. Different scientific researchers represent a wide range of values for the coalbed reservoir geological parameters. For this reason, two currently developing fields are studied to reference the data with realistic values San Juan Basin – Fruitland Formation and Black Warrior Basin – Pottsville Formation

Data collected from the simulations of coalbed reservoir in the different project was also used. (Mora & Wattenbarger, 2009) are comparing the computation methods for CBM Performance. This paper shows the predictions results of reservoir behaviour performed in such simulation environments as PRODECY, F.A.S.T. CBM, GEM and ECLIPSE. Some of the reservoir parameters and production data could be found in (Z. Dong et al.) paper which shows approximate estimation and distribution of the CBM recoverable resources worldwide. Numerical solutions are also represented by (Perera et al., 2015). The author performs simulations using COMET 3 tool to optimise enhanced CBM recovery. (Zuo – tang et al., 2009) represents CBM recovery and CO_2 sequestration simulation using Zhongliangshan coal mine in China as an investigated field. (Ibrahim & Nasr – El – Din, 2015) in their CBM simulations use both theoretical cases related to the real numerical solutions, and also reservoir properties (San Juan Basin and Black Warrior Basin). All mention data are analysed and averaged values of the range of parameters were chosen for the simulation model.

There is a summary of all data used in the further simulations.

Table 2 – Reservoir data

Parameter	*Value*
Initial reservoir pressure, psig [1,2]	700
Gas composition (CH_4), %	100
Reservoir temperature,°F [3]	100
Reservoir permeability, mD[3]	10
Fracture permeability, mD [4]	5
Matrix permeability, mD [4]	0.1
Reservoir porosity, % [3]	1
Fracture porosity, %[1]	0.01
Matrix porosity, %[1]	0.01
Reservoir thickness, ft	50
Reservoir area, acres	250
Coal bulk density, g/cm^3 [3]	1.43
Coal compressibility, 1/psi	7.1245e – 006

1 (Mora & Wattenbarger, 2009)
2(Kaiser & Ayers Jr, 1994)
3 (Ibrahim & Nasr – El – Din, 2015)
4 (Ayers Jr & Kaiser, 1994)

General reservoir data is shown in Table 2

Table 3 – Langmuir Isotherm Parameters[5]

	Units	*CH_4*	*CO_2*	*N_2*
Max. Gas content, Langmuir vol. constant	m3/tonne	23.720	35.900	21.700
Langmuir pressure constant	psi	559.845	435.114	928.238
Equivalent of Langmuir pressure, b	1/psi	0.00178622	0.00229823	0.00107731
Initial gas content	m3/tonne	13.179	22.139	9.329

5 (Özgen Karacan, 2013)

Table 4 – PVT parameters

Parameter	*Value*
Gas gravity, sp. gravity	0.6
Water salinity, ppm	25000
Gas to liquid ratio, scf/STB	0

Table 5 – Residual saturation table

	Residual Saturation, fraction	*End Point, fraction*	*Exponent*
Krw[3]	0.01	0.6	3.9
Krg[3]	0.01	0.72	2

Equipment data for Well 1 CBM Producer and Well 2 CBM Producer; Well 3, Well 4 and Well 5 (Injection wells)

Table 6 – Deviation survey

MD(feet)	*TVD(feet)*
0	0
2600[6,7]	2600

6 (Z. Dong et al.)

7(Ayers Jr & Kaiser, 1994)

Table 7 – Geothermal data

Formation TVD (feet)	*Formation MD (feet)*	*Formation Temperature (F)*
0	0	60
2600	2600	100

Table 8 – Average heat capacities

Cp Oil	0.53	BTU/b/F
Cp Gas	0.51	BTU/b/F
Cp Water	1	BTU/b/F

Downhole equipment data is described in Table 9.

Table 9 – Downhole equipment data for production and injection wells

Type	*MD*	*Tubing Inside Diameter*	*Tubing Inside Roughness*	*Tubing Outside Diameter*	*Tubing Outside Roughness*	*Casing Inside Diameter*	*Casing Inside Roughness*
Tubing	2500	2.875	0.0006	3.25	0.0006	6.1	0,0018
Casing	2600					6.1	0,0018

Table 10 – Pipeline data

Distance	*Segment Type*	*Length, m*	*TVD, m*	*Inside Diameter, inches*	*Roughness, inches*
Well – Joint	Line pipe	500	0	5	0.0006
Jointg –Separator	Line pipe	300	0	4	0.0006
Well – Manifold	Line pipe	500	0	5	0.0006

3.3 IPM: building the model

3.3.1 Model in PROSPER

In PROSPER it is possible to model CBM Producer well which allows performing both de – watering and gas production stages. Reservoir pressure reduces during the dewatering stage and gas desorbs from the coal matrix surface thus becomes available for the further production. A pump is typically installed at the tubing bottom and that allows to produce more fluid. Produced gas is directed to pass through the well annulus by the gas separator.

So, main challenges for modelling in PROSPER are:

- to create 2 models of CBM production wells;
- to select appropriate electrical submersible pumps;
- to create 3 models of injection wells for each case of injection fluid (N_2, CO_2 and their mixture);
- to export all data to GAP for the further modelling.

3.3.1.1 Production Wells In PROSPER

There is a set of parameters that should be determined in order to build the appropriate simulation model. The most important of them are PVT relation, Vertical lift performance (VLP), Inflow performance relationship (IPR).

Firstly, to predict pressure and temperature changes along the reservoir and wells it is necessary to enter data which describes coalbed methane properties in the PVT section of PROSPER. Fluid properties will be used in the further calculations. Equipment data should be entered to build Vertical lift performance curve.

Downhole equipment in the equipment section is defined by the given drilling data and equipment parameters. Here it is necessary to define the path which the well takes to surface – deviation survey. Formation temperature profile is used for heat transfer calculations to determine the difference between the fluid and surrounding rock. Default heat capacity data were used. Wells 1 and 2 were made identical.

Inflow performance relationship model for CBM reservoir is "CBM Producer model" – it shows the well inflow and possible productivity of the simulated reservoir. This model allows simulating each phase for the IPR separately. One of the most important parameters in this section is relative permeability of each phase (water and gas) and its influence on the production. Reservoir data and suggested Productivity Index (PI) were entered into the model (Petroleum Experts, 2015b).

Calculated absolute open flow (AOF) for the production well is 838.8 STB/day. Now when equipment is set and IPR data is entered it is required to specify the ESP data.

Table 11 shows chosen ESP characteristics for both production wells.

Table 11 – ESP characteristics

Pump Parameter	*Value*
Pump measured depth, feet	2500
Operating frequency, Hertz	50
Maximum Pump OD, inches	6
Length of cable, feet	2500
Gas separator efficiency, %	100
Liquid level, feet	2000
Number of stages	87
Voltage at surface, Volts	430
Pump wear factor, fraction	0
Current pump	CENTRILIFT FC450 4 inches (200 – 625 RB/day)
Current motor	Centrilift 450 24HP 430V 34A
Current cable	# 1 Copper 0.26 (Volts/1000ft) 123 (amps) max

VLP and Pump Discharge Pressure (PDP) curves intersection determines wells deliverability conditions. Pump discharge pressure shows at what pressure fluid leaves a pump. It is one of the main parameters in the system calculations. It was calculated that AOF for water production is 197.5 STB/day at the pump discharge pressure of 1199 psig – in the case of reservoir pressure 600 psig and GLR equal to 0.1.

3.3.1.2 Injection system

A similar procedure is made to build the injection wells model. Different cases of injection for enhances recovery are considered in this thesis project.

They are:

1. N_2 injection;
2. CO_2 injection;
3. N_2 alternating CO_2 injection;
4. N_2 and CO_2 mixture injection

For these scenarios injection system should consist of 3 wells. Well 3 – injected gas is N_2, Well 4 – injected gas is CO_2, Well 5 – injected fluid is a mixture of N_2 and CO_2. General information about the case and used wells is shown on the

Table 12 – Wells and cases: general information

Case 1	Well 3
Case 2	Well 4
Case 3	Well 3, Well 4
Case 4	Well 3, Well 4
Case 5	Well 5

To perform the simulation for all mentioned above cases, appropriate scheduling for the wells injection period should be used. PVT data is entered similarly to the production wells. Equipment data were entered for each well. To simplify the model, downhole equipment data was chosen similar to the production wells.

VLP calculation is performed. The model for IPR that appropriately fits the reservoir model is "Dual Porosity Model" (Petroleum Experts, 2015b). Also, all parameters are divided into 2 groups: characteristics of fracture system and characteristics of coalbed matrix. Some of the parameters as Interporosity (IC) coefficient and Storativity ratio (Ibrahim & Nasr – El – Din) for the coalbed methane reservoir are calculated using equations:

$$SR = \frac{\emptyset_f \cdot C_f}{\emptyset_f \cdot C_f + \emptyset_m \cdot C_m} \tag{7}$$

$$IC = \frac{k_m}{k_f} \cdot r_w^2 \cdot D \tag{8}$$

Where *k* is permeability, $\emptyset$ – porosity, *C* – compressibility, indexes *f* and *m* are for fraction and coal matrix parameter respectively

Storativity ratio is the ratio of fracture storativity to the total. Where total is equal to the sum of matrix and fracture (Petroleum Experts, 2015b). Interporosity coefficient is the ratio of matrix to fracture permeability multiplied by the effective well radius and a shape factor (Warren & Root). Dietz shape factor D is equal to 31.62 and that means that reservoir has the form of the circle.

In injection wells AOF value is not so important, since there is no limitation to what bottom hole pressure could be. While in the production well case, where AOF is limited by 0 psig (Petroleum Experts, 2015b). Additionally, rates which are going to be used in system calculation were generated manually. VPL and IPM calculations also were performed in the model building.

3.3.2 Reservoir Modelling in MBAL

3.3.2.1 Material balance and diffusion effect for the CBM reservoir

MBAL is a reservoir engineering tool that helps to perform the analytical study of the reservoir. In that case, it helps to make CBM reservoir calculations. Since the material balance is the main idea of that tool it is necessary to mention that it is the form of the conservation of mass in the reservoir. In general, it could be written as*: the Initial amount of fluids in the reservoir – Amount of the produced fluid = Remained amount of fluid.*

Material balance module for the tight gas is used for simulation. According to (King, 1993) Desorbed amount of gas is included in the material balance calculations including prediction simulation. Material balance calculations for the dual porosity system is represented by the equations 5 and 6. That equation assumes that Langmuir Isotherm type of curve is used for the coal adsorption characterization. (King, 1993)

$$G_p = \frac{V_{b2}\emptyset_i z_{sc} T_{sc}}{p_{sc} T}\left(\frac{p_i}{z_i^*} - \frac{p}{z^*}\right); \tag{9}$$

$$where\ z^* = \frac{z}{[1 - c_\emptyset(p_i - p)](1 - \overline{S_w}) + \frac{zTp_{sc}}{z_{sc}T_{sc}} \cdot \frac{V_L}{c_\emptyset(p_L + p)}} \tag{10}$$

Where G_p represents produced gas, V_{b2} is bulk volume of secondary porosity system, $\emptyset_i$ – initial porosity, dimensionless, fraction; z, z_{sc} – gas supercompressibility factors; $\mathbf{z}^*$ – gas factor for unconventional gas reservoir, dimensionless; $\boldsymbol{z_i^*}$ is initial gas an factor for unconventional gas reservoir, dimensionless; $\mathbf{p}, p_{sc}, p_i$ represent pressure, at reservoir conditions, standard contitions and initial conditions respectively; T, T_{sc} – temperature at reservoir and standard conditions respectively; p_L – Langmuir isotherm pressure constant; V_L – Langmuir isotherm volume constant; $c_\emptyset$ – porosity compressibility.

The main method of the CBM reservoirs simulation is the Langmuir Isotherm. It models the amount of adsorbed in the coal gas. As reservoir pressure decreases more gas is desorbed from the coal and released into free phase. The Langmuir Isotherm defines the relationship between the reservoir pressure and the amount of adsorbed in the coal matrix. This relation could be represented per volume or mass (Petroleum Experts, 2015b).

All methods for the coalbed methane in MBAL are modified methods from the tight gas tool. The method is described by (Bumb & McKee, 1988). It allows to create an approximate solution for the reservoirs where gas exists in both free and adsorbed form. Adsorption data is represented by the adsorption isotherm. Langmuir isotherm has limitation for the amount of adsorbed methane.

$$V_E = \frac{V_L \cdot p_g}{p_L + p_g} \qquad (11)$$

Where p_g – gas pressure, p_L – Langmuir pressure, V_E – volume of gas adsorbed at pressure p_g (per volume), V_L – Langmuir volume.

Langmuir pressure is the pressure at which total amount of volume is adsorbed. The volume of gas adsorbed at that pressure is equal to one – half of the Langmuir volume. Latter shows the maximum sorption capacity of the coal (Bumb & McKee, 1988). So, the model assumes that desorption follows a Langmuir isotherm. The model assumes that reservoir has homogeneous properties and single – phase gas flow, is at an isothermal condition (Bumb & McKee, 1988). Equation 3 for the Extended Langmuir isotherm is used in the model for the calculations.

In coalbed methane reservoirs, the value of compressibility increases the whole production. Original gas volume increases by the addition of expanded original gas and desorption of gas in coal matrix. Compressibility term for the tight gas model is corrected in order to include desorption term in the calculations, thus making the model for tight gas appropriate for the coalbed reservoir calculations (Petroleum Experts, 2014).

Langmuir Isotherm shows that connection between the pressure and the amount of adsorbed gas. If the time period for the 1 pressure drop is assumed non – instantaneous then there should be a delay because of the diffusion effect. (Petroleum Experts, 2014)

Modified form of the Fick's law equation proposed by King (Equation 8), based on time rather than on distance, is used in MBAL to simulate the diffusion effect. (Petroleum Experts, 2014), (King, 1993)

$$q_g = \frac{-DAz_{sc}RT_{sc}}{p_{st}} \frac{dC_m}{dx} \qquad (12)$$

Where D is a diffusion constant and C_m is molar concentration.

$$V_e = V_{e2} + (V_{e1} - V_{e2}) \cdot exp(-Dt) \tag{13}$$

If the diffusion process has started at the pressure where $Ve = Ve1$ and decreased to the pressure at what $Ve = Ve2$ then the desorbed amount of gas is equal to the equation 9. The principle is described in Figure 13. Superposition principle is used to add the effect from diffusion from each pressure step to the total pressure decline.

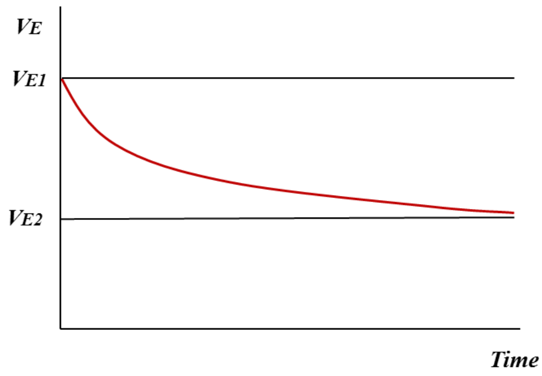

Figure 13 – Fick's Law representation for 1 pressure and time step, (Petroleum Experts, 2014)

3.3.2.2 Building of the Reservoir Model

In the Langmuir Isotherm Editor following parameters are chosen:

- Adsorption gas entry method – surface gas / volume (scf/tonne);
- Normally saturated reservoir;
- Extended Langmuir Isotherm;
- Test type – as received.

Langmuir volume and pressure and bulk coal density values are entered into the model. Rock compressibility is calculated from the correlation. By entering the dimensions of the reservoir it is possible to calculate appropriate initial gas and water content for a given Langmuir Isotherm.

After the estimation OGIP is equal to 10261.9 MMscf and initial water in place is equal to 0.966178 MMSTB. It is assumed that there is no free gas in the reservoir and it is initially fully saturated with water. The graph of Langmuir adsorption isotherm taken from MBAL is represented in Figure 14.

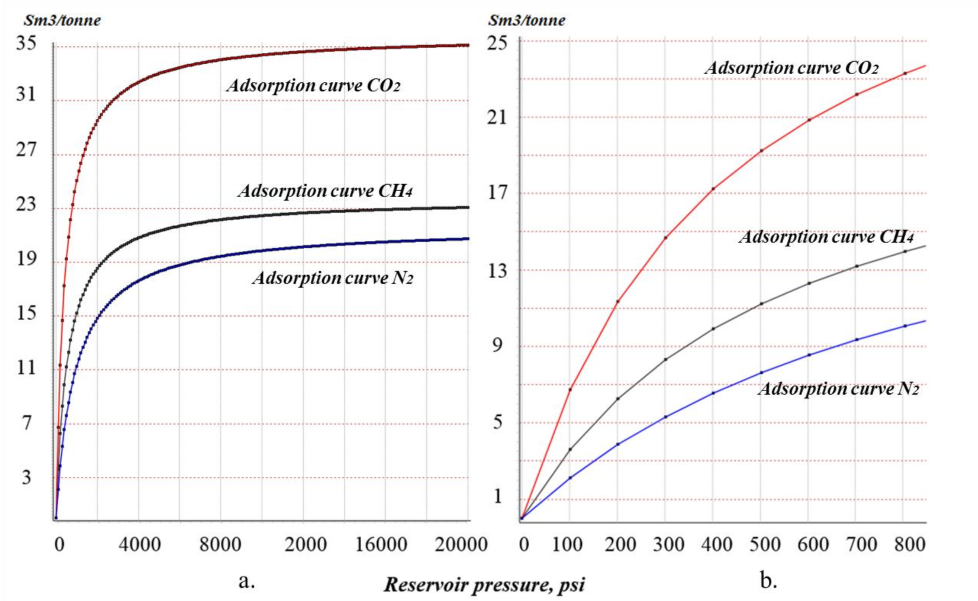

Figure 14 – Langmuir Isotherm (IPM): a. reservoir pressure range: 0 – 20000 psi; b. – reservoir pressure 0 – 800 psi

3.3.3 GAP

Two systems were made in this project: production and injection systems. Injection system was made to perform the enhanced coalbed methane recovery.

3.3.3.1 Production System

Principle scheme of the production system is represented in Figure 15.

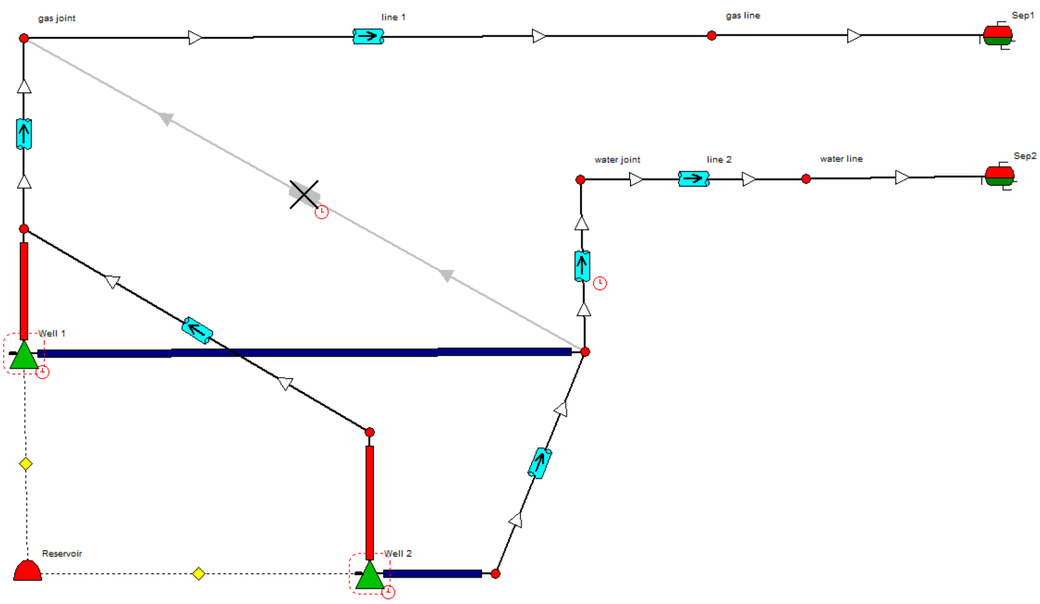

Figure 15 – Principle scheme of the production system

Production system consists of the reservoir with 2 production wells, which are connected to the corresponding separators through the gas and water pipes. In this project, production of the reservoir should be predicted in order to choose the appropriate moment for the start of the ECBM production.

3.3.3.2 Well definition in GAP

To define the reservoir and its properties, made before MBAL file is associated with the tank. Well model files are also associated with corresponding wells in GAP. The electrical submersible pumps (ESP) in the production wells should be replaced with a tubing and a packer after the massive dewatering period. Principle scheme of the well is represented on Figure 16. (Petroleum Experts, 2015a)

CBM production well has two production lines: gas production from annulus (red), water production from the tubing (blue). Two separators are used in that system because there are two periods of production:

1. Production with ESP with downhole separation of gas and water. Production starts in 01/01/2017. Since that each well produces gas and water separately to the Separator 1 (for gas lines) and Separator 2 (for water lines).
2. Production without ESP. In 2019 ESP was replaced by the annulus packer and all further production is redirected to by the tubing line to the Separator 1

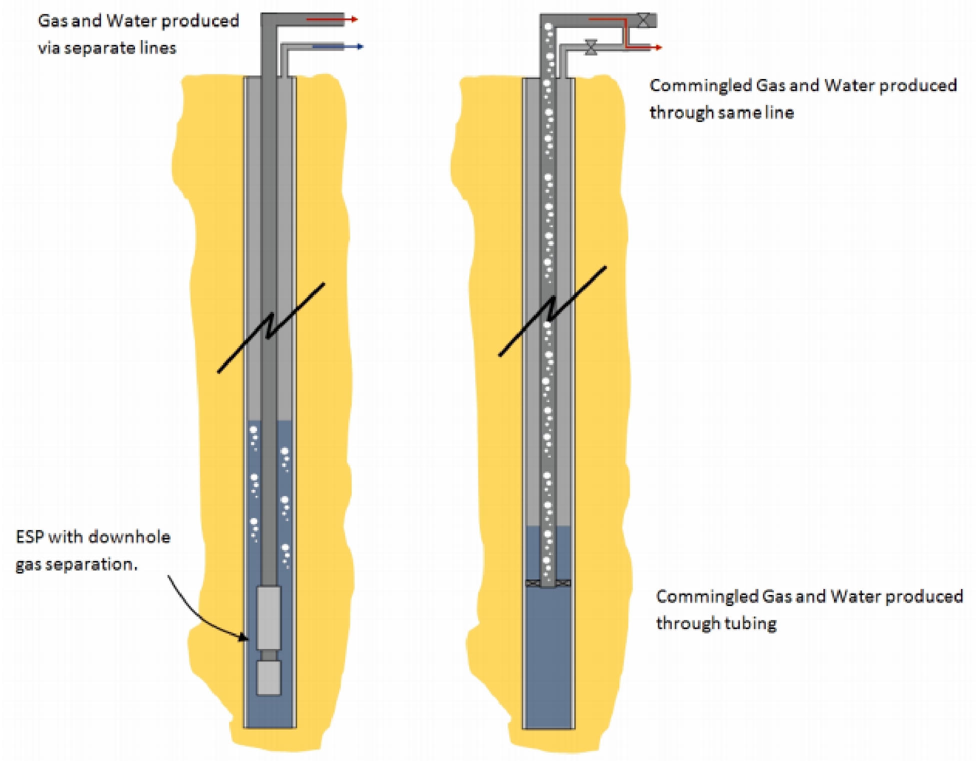

Figure 16 – Production wells with ESP and without ESP (Petroleum Experts, 2015a)

The date for the ESP removal was determined by performing different simulations. The prediction was performed until the 2047 (30 years) to observe the difference in the cumulative gas and water production used different options for the pump deactivation date. Sensitivity for the pump removal date was chosen as 4 dates: 1/1/2019, 1/1/2020, 1/1/2021 and 1/1/2022. Gas and water rates curves are described in Figure 17. Here it could be noticed that the earlier is the date of pump removal, the higher is the peak of gas and water rate: 1.95 MMscf/day for gas and 280 STB/day for water.

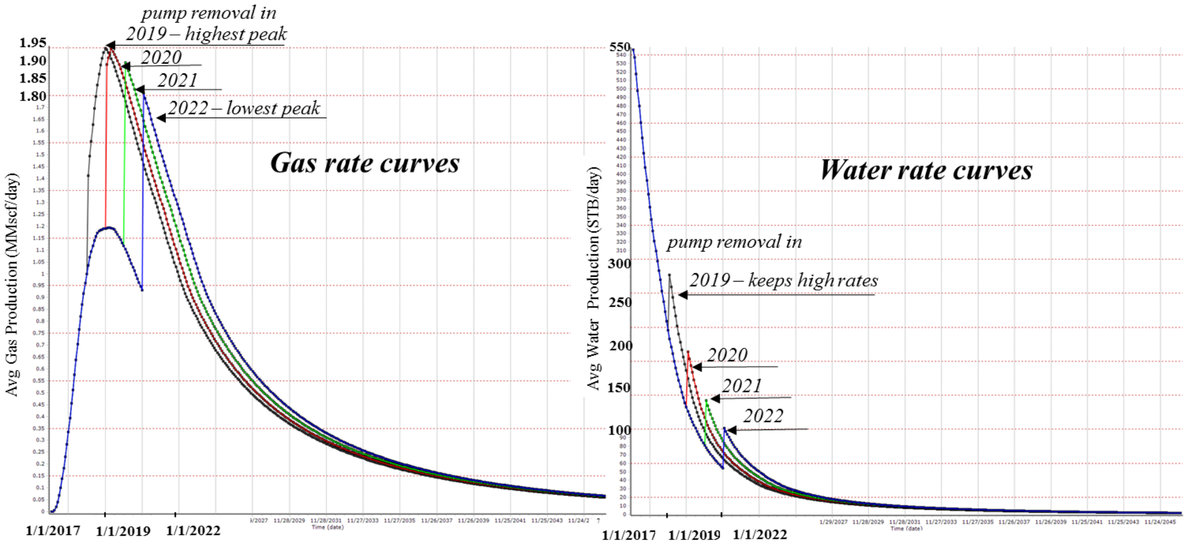

Figure 17 – Gas and water rates for the pump removal sensitivity case

Table 13 – Cumulative water and gas production for the pump removal sensitivity case

Date of the switch off the ESP	*Cumulative water production, MMstb*	*Cumulative gas production, MMstb*
1/1/2019	0.5251	5410.158
1/1/2020	0.5248	5403.009
1/1/2021	0.5244	5393.826
1/1/2022	0.5242	5383.085

From the Table 13, it could be observed that more gas and water was produced in during the shortest period of pump exploitation. This date – 1/1/2019 was chosen as pump removal date for the further investigations.

Scheduling was used for switching between periods with and without ESP. Masking and respectively unmasking of the pipelines for the several periods are desirable to redirect the flow.

A well model should be able to predict the production rate and pressure characteristics such as bottom hole pressure. These predictions are made related to wellhead pressure, GOR, WC and other conditions. This prediction is made from the results of IPR and VLP intersection, which determines the flowing rate and bottom hole pressure in the conditions of the building model. Thus, to make the accurate and full well model, it is needed to know the solution of these two relationships (Petroleum Experts, 2015a). IPRs and VLPs were generated for the selected well models. The model of the production system is full and ready for the further prediction.

3.3.3.3 Injection System

Injection system principle scheme is represented in Figure 18.

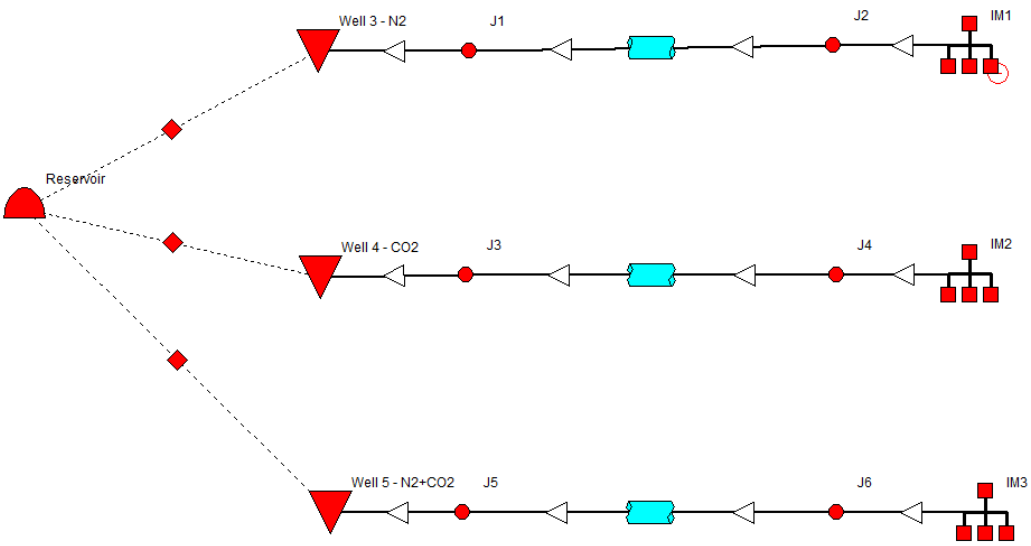

Figure 18 – Principle scheme of the injection system

The injection system is represented by the reservoir, three injection wells and three injection manifolds. Manifold models are built separately to allow the simultaneous injection from different injection wells. The procedure of making the model is similar to the production one.

3.4 CMG: building the model

To be able to compare the results of the study, the model in CMG wad made very similarly to the one in IPM. All the same, data was used for the following model development.

3.4.1 Reservoir model in Builder

The first thing that was made in the Builder was the division of the reservoir on the grid blocks. It contains 9 blocks along the radius (r divisions), each of them has a width of 206.87; 20 angular blocks ('theta divisions') with a width of 18 degrees (in sum 360); and 10 vertical divisions. The overview is displayed in Figure 19.

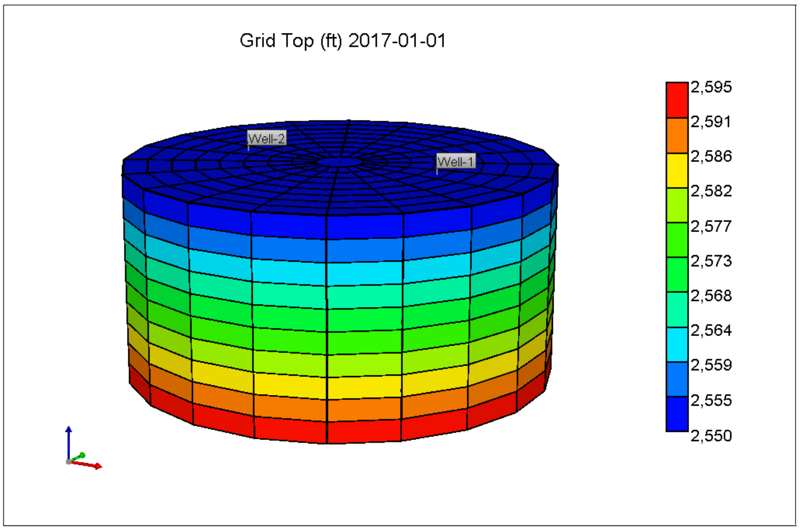

Figure 19 – Reservoir overview in Builder

All needed reservoir data was entered to the "Specify property" section and then missing parameters for the simulation were calculated by Builder.

Adsorption modelling in CMG is also represented by the Langmuir Isotherm. If the pressure and temperature conditions of the investigated reservoir are known, Langmuir Isotherm could be used to calculate the maximum amount of gas (methane) which is adsorbed on the coal surface. Also it is possible to estimate at what pressure the desorption process will start. (Computer modelling group, n.d.)'

Equation 7 described before is used to build the Langmuir Isotherm. Equation 3 for the Extended Langmuir isotherm which is based on the single component Langmuir Isotherm is used by GEM for the calculations. It makes a multi – componential model construction available.

Section "Quick CBM Set Up" allows entering all the data required for the isotherm calculations. Maximum adsorbed mass, Langmuir constants were added to the model.

Diffusion of gas to the fractures model in CMG is also based on the Fick's Law which could be represented by the equation 10

$$Q = [Vol \cdot Shape \cdot D] \cdot F(Sg) \cdot [C(k,m) - C(k,f)] \qquad (13)$$

Where *Vol* is cell volume; *D* – diffusion value; *F(Sg)* – function of fracture gas saturation modelling water blocking; *C (k, m)* – mass concentration of species k in the free gas phase in the matrix; *C(k, f)* – mass concentration of species k in the free gas phase in fractures.(Computer modelling group, n.d.)

Also, it could be calculated using another method by the equation 11

$$Q = [Vol \cdot Shape \cdot D] \cdot F(Sg) \cdot [Lang(k,m) - Lang\ (k,f)] \qquad (14)$$

Where Lang *(k, m)* is an extended Langmuir Isotherm for the coal, multiplied by coal density evaluated at the composition and pressure of matrix, and Lang *(k, f)* is the same parameter for the fracture.(Computer modelling group, n.d.)

There are several suggested by the software initialization method for the Langmuir isotherm calculations. "Vertical depth ave water gas" was used to create 2 initialisation regions: 1st region is characteristics for coal matrix, 2nd region – fracture system characteristics.

Then "Quick" method of region type selection was chosen: it implies that one Langmuir curve corresponds to each component for the whole reservoir model. The advanced parameter in this tool allows setting reservoir fluid as a 100% CH_4.

After entering the adsorption data, equilibrium pressure at the initial gas content was calculated and it is equal to the 700 psi in the case of each gas. That means that fracture pressure is equal to the matrix pressure and the reservoir is saturated.

Received Langmuir Isotherm curves are represented in Figure 20.

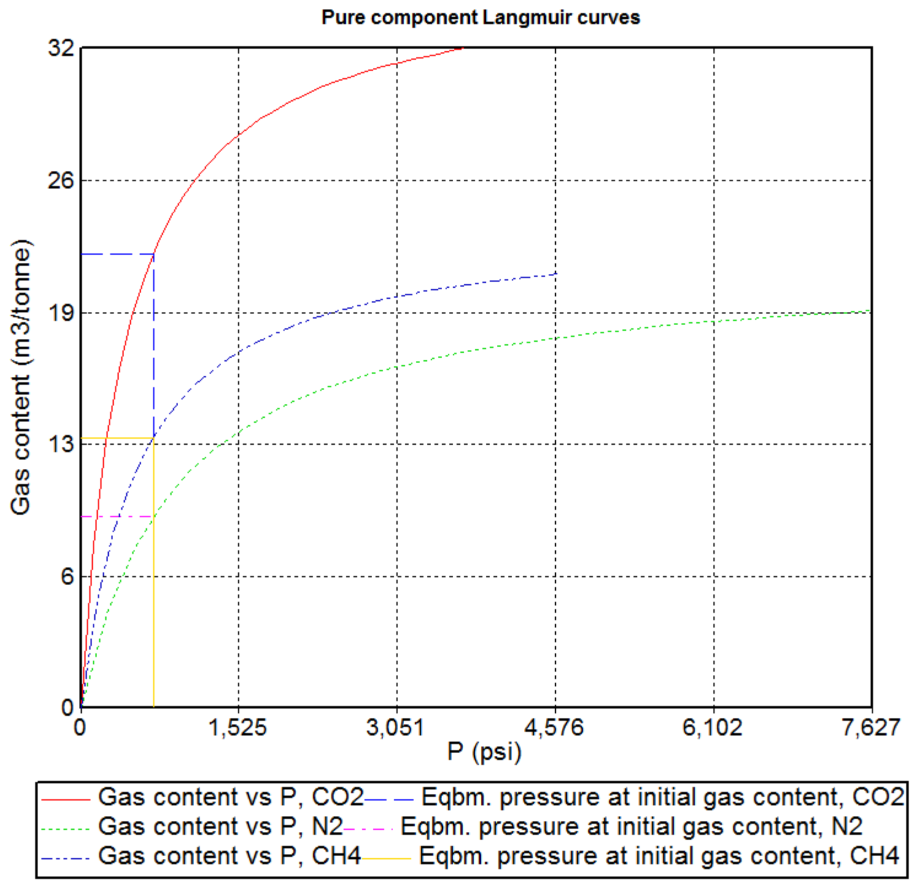

Figure 20 – Langmuir Isotherms from the Builder (CMG)

Gas in place is calculated on the base of volumetric in the fracture system. That amount is added to the gas in place estimated in the matrix by the Langmuir Isotherm calculations.(Computer modelling group, n.d.) Gas in place is equal to the 10350 MMscf. This value is slightly higher than the value estimated by the IPM but the result is comparable.

3.4.2 Production and injection wells in Builder

Wells data was entered into the well definition section. Several model files were made to cover all investigated cases. E.g. in the case with no enhanced recovery only 2 production wells were simulated. While in the case of alternating injection there were 2 more additional injection wells: one for CO_2 injection and another for the N_2 injection. In the case of the mixture injection, there was made one compositional injection well. In total, 43 models were built for different studied cases: originally investigated and also additional cases. Injection wells are situated in the centre of the reservoir. Production and injection pattern is represented in Figure 21.

Figure 21 – Principle scheme if the production and injection wells pattern

3 perforations in the lowest grid levels were made for the production wells and only 1 perforation for the injection wells. 3 perforations in the low layers in the production wells allows to perform dewatering more effectively, so less no water will be trapped under the point of the perforation.

Well event manager allows to schedule well performance, change parameters (constraints) and switch on or off injection wells. The constraint of the wells are represented in Table 14:

Table 14 – Well constraints, Builder

Production well	
Surface water rate, bbl/day	600
Surface gas rate, ft3/day	130000000
Wellhead pressure, psi	100
Injection well (100% N_2 injection)	
Bottom hole pressure, psi	1000
Surface gas rate, ft3/day	650000
Injection well (100% CO_2 injection)	
Bottom hole pressure, psi	1000
Surface gas rate, ft3/day	1200000
Injection well (mixture injection)	
Bottom hole pressure, psi	1100
Surface gas rate, ft3/day	1000000

3.4.3 Additional cases modelling

3.4.3.1 Case 6 – 4 production wells

During the process of the simulation, some of the models had to be changed and re – simulated as additional cases.

To show that the reservoir production could be increased if production wells pattern is distributed through the whole field case 6 was performed. 2 more production wells were added to the original pattern as it is it shown Figure 22. Case 5.5 (87% N_2 and 13% CO_2 mixture injection) was repeated with new production conditions and injection wells properties stayed the same. Wells constraint was not changed.

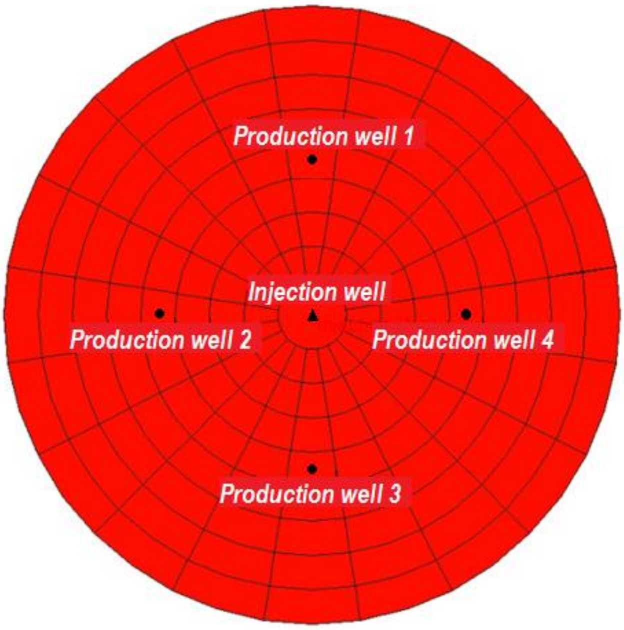

Figure 22 – 4 production wells pattern scheme

3.4.3.2 Additional cases 3 and 4

Additional cases 3 and 4, fully described in the results and discussion chapter, were made to perform the sensitivity study in the alternating type of injection. Implementation of the N_2 - CO_2 and also CO_2 - N_2 alternation injection is not completely studied yet. It is important to understand what factors affect more on the production recovery in the case of alternation injection, to optimise explicitly the process of injection and also to reach the enhanced recovery goals. In this thesis, 3 possible factors of influence were made as a sensitivity study,

1. If there is a certain definite repeating period of injection – 5 – year cycle: in what proportion should N_2 and CO_2 be to reach the highest results values. How the short or long duration of Nitrogen or Carbon Dioxide injection effect on each other. The other point of the investigation is what gas should be injected first and is there any difference in the coal interaction with gases in these cases.

4 cases with the gradually increasing amount of CO_2 relative to Nitrogen with each scenario (giving 5 years in total) were made for the case where N_2 is the first injected gas. Respectively, 4 cases with the gradually increasing amount of N_2 relative to CO_2 with each scenario were made for the case where CO_2 is the first injected gas.

2. If the ratio between the N_2 and CO_2 injection period is kept constant as 1 – to – 1, with what frequency is it more efficient to perform the injection cycles. 5 injection scenarios were made for each additional case: N_2 - CO_2 alternation and CO_2 - N_2 alternating injection. Injection cycle duration was changed from 1 year (where half of the injection cycle is the injection of 1st gas and another half – 2nd gas) to 10 years.
3. If ratio between the N_2 - CO_2 or CO_2 - N_2 injection is changed, which scenario would be the most efficient with ratio 1:2, 1:3 or 1:4

Builder models were made on the basis of already performed injection cases 3 and 4, while well events in the well manager were changed respectively to the needed injection scenario conditions. Thus 24 new models were made and simulations were performed in the way described before. Additional case with new production and injection well pattern

To prove that the results tendency would be the same if both production and injection well distribution will be made in the other way that is already performed in the thesis, this case was made. New injection and production pattern are represented in Figure 23.

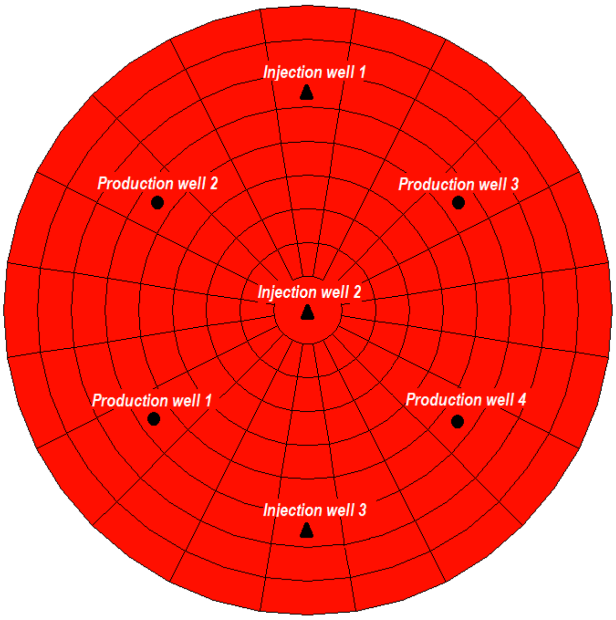

Figure 23 – New production and injection wells pattern

3 cases were re-simulated in order to compare the production prediction results.

Results of all performed simulations are represented in the next chapter.

Chapter 4
Results and Discussion

As it was already described in the methodology and model description section, there are several ways of getting the high methane production from the coalbed reservoir. First of all, it is water removal technique that allows producing almost the half of the reservoir in place fluid. Another way to enhance production recovery is to use gas injection: CO_2, N_2 or mixture of them.

To ascertain the effect of the ECBMR technique it's necessary to find out its dependence on the following factors:

- ✓ Injection gas composition;
- ✓ Duration of the injection period;
- ✓ Adsorption characteristics of injected gases;
- ✓ Injection fluid interaction with coalbed seam and CH_4

Also in this thesis, the important discussion question is the influence of the simulation software on the prediction results.

4.1 Cases Description

Taking in consideration different enhanced recovery methods, 5 cases of injection were done to perform the sensitivity study. All cases were performed with the constant wellhead pressure of 100 psi.

4.1.1 Case 1

Enhanced recovery method chosen for the ECBMR is 100% Nitrogen injection. The injection well is located in the centre of the reservoir.

4.1.2 Case 2

Same as the 1^{st} case but chosen for injection gas concentration in 100% CO_2.

4.1.3 Case 3

Nitrogen injection has been started in 01/01/2027. Sensitivity study, in this case, is made to show the dependence of the recovery from the time of injection. For that purpose, N_2 and CO_2 injections were performed alternatively. The time scheduling for the predicted scenarios is represented in the table. The date of CO_2 injection for the case 3.3 is 1/1/2040 to avoid too large concentration of N_2 produced with the total gas production (breakthrough). The limitation here is 50% of N_2 in the production stream before the implementation of the CO_2 injection. The amount of N_2 greater that 50 % or the half of the reservoir gas production is theoretically possible, but not realistic and is obviously beyond the purpose of the enhanced production.

Table 15 – Schedule of injections performed in Case 3

Case 3	*Date of the N_2 injection*	*Date of the CO_2 injection*	*% of N_2 in the CH_4 production in the year of CO_2 injection*
Case 3.1	1/1/2027	1/1/2032	25
Case 3.2	1/1/2027	1/1/2036	40
Case 3.3	1/1/2027	1/1/2040	50

Thus, N_2 and CO_2 injections were made for 5, 9,13 and 15, 11, 7 years respectively.

4.1.4 Case 4

Carbon dioxide alternating nitrogen injection. This case is repeating the sensitivity study performed in the Case 3 but the order of the injection gases is opposite. CO_2 injection has also been started in 01/01/2027. Injections were made for 7, 11, 15 and 13, 9, 5 years in for CO_2 and N_2 respectively. Dates for the N_2 injection were chosen similarly to the case 3.

Table 16 – Schedule of injections performed in Case 4

Case 4	*Date of the CO_2 injection*	*Date of the N_2 injection*	*% of CO_2 in the CH_4 production in the year of N_2 injection*
Case 4.1	1/1/2027	1/1/2034	25
Case 4.2	1/1/2027	1/1/2038	40
Case 4.3	1/1/2027	1/1/2042	50

4.1.5 Case 5

Injection gases have been mixed up in different proportions, represented in Table 17. N_2 presence in the injection mixture is decreasing in cases 5.1 – 5.4 from 80 to 20 %. Case 5.5 is made close to the common fuel gas composition. Injected composition is 87% of N_2 and 13% of CO_2. (Perera et al., 2015) describe this composition as one of the most effective for the ECBMR. Theoretically, the response for the injection, in this case, is higher than with 100% N_2 or 100% CO_2 because of the higher interacting of these gases together with the coal seam. From the other hand, this composition requires less pre – treatment for the injection gases and therefore could reduce ECBMR cost. Case 5.6 represents mixture injection with the equal concentration of CO_2 and N_2 is considered to find out which of these gases effects more on the production behaviour.

Table 17 – Case 5. Description

Case 5	*% of N_2 in the mixture*	*% of CO_2 in the mixture*
Case 5.1	80	20
Case 5.2	60	40
Case 5.3	40	60
Case 5.4	20	80
Case 5.5	87	13
Case 5.6	50	50

4.2 IPM Simulation Results

4.2.1 Primary Coalbed Methane Recovery

The prediction was performed for 30 years. Production prediction period is 1/1/2017 – 1/1/2047. Before investigating the enhanced recovery sensitivity study it is necessary to determine primary production simulation results.

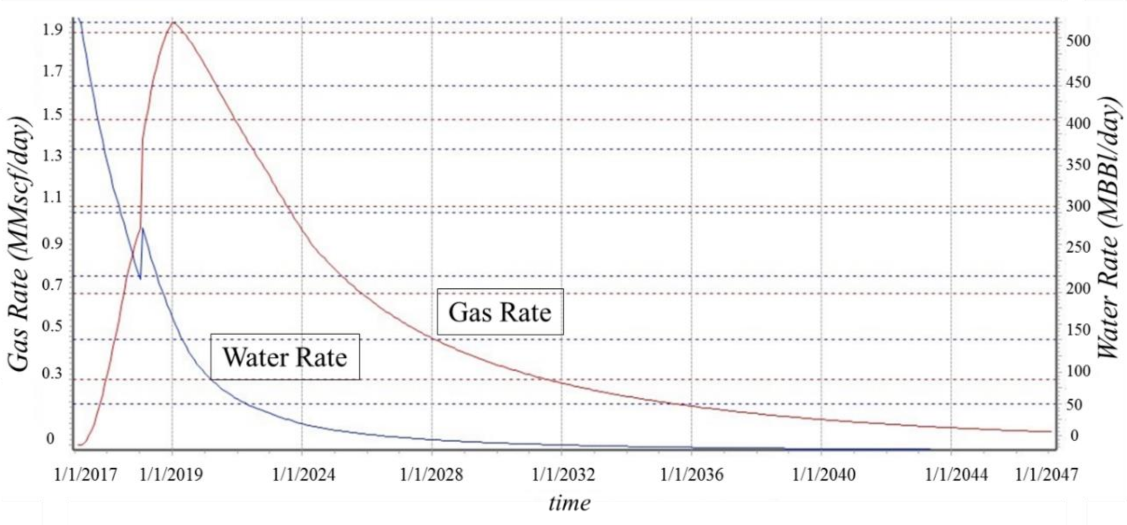

Figure 24 – Water and gas rate curves. Production Period (1/1/2017 – 1/1/2047)

Figure 24 shows production rate curves from 2 production wells. Gas rates increase as the water rates decrease. This figure shows the most typical behaviour of the CBM reservoir. Production stages described earlier could be determined from the graph:

1. Dewatering stage: water rate increases significantly because of the implementation of the ESP. Pump work period was 2 years since the start of field production. Rapid production of water induces methane desorption from the seam. Gas production, therefore, increases. The model considers that the conventional production wells replace ESP wells. At this moment (1/1/2019) instability on the water rate curve can be observed.
2. The 2nd stage implies the high gas production rates and the peak of the gas rate curve. At the same time, almost the half of water in place has already been produced and water rate becomes relatively small.
3. During the 3rd production stage, water production rates remain low while gas rates start to decrease with the reservoir pressure decline.

Reservoir pressure decline and cumulative gas production curves are represented in Figure 25.

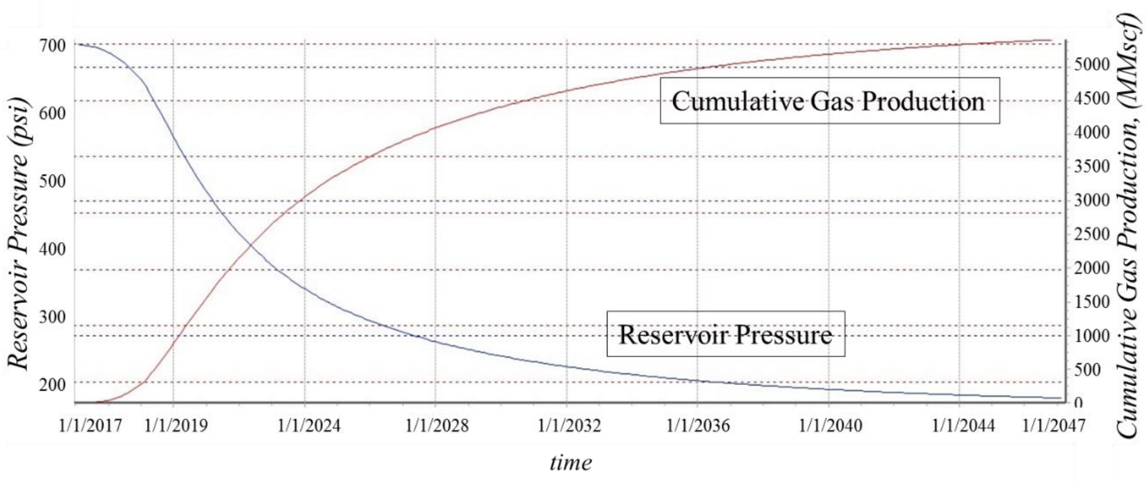

Figure 25 – Cumulative gas production and pressure decline curves production period (1/1/2017 – 1/1/2047)

From the production rates profile, it could be observed that gas rates reduce significantly from the peak values (1.9 MMscf/day in 2020) to the low values (lower than 0.3 MMscf/day since 2035).

Recovery is equal to 53.1%. That number could be increased by considering enhanced recovery technology. To improve the gas rate behaviour and to increase cumulative gas production it is considered to apply stimulating gas injection in the 1/1/2027.

4.2.2 General Data

Simulations were performed and results are represented in Table 18.

Table 18 – Prediction results. Cumulative CH_4, N_2 and CO_2 production for all simulation cases

Type of injection	*Case*	*Cumulative production, 1/1/2047, MMscf*		
		CH_4	*CO_2*	*N_2*
no injection	Case 0	5388.790	–	–
N_2 injection	Case 1	7734.405	–	2377.484
CO_2 injection	Case 2	7990.256	2070.344	–
N_2 and CO_2 injection	Case 3.1	7781.629	1127.454	904.615
	Case 3.2	7723.379	512.948	1596.016
	Case 3.3	7717.080	195.390	2056.455
CO_2 and N_2 injection	Case 4.1	7859.747	1093.634	1230.492
	Case 4.2	7901.394	1534.015	706.727
	Case 4.3	7921.415	1898.207	193.616
N_2 and CO_2 mixture injection	Case 5.1	8237.610	369.465	3429.468
	Case 5.2	8138.199	715.994	2529.156
	Case 5.3	8015.501	1031.558	1648.061
	Case 5.4	7860.997	1304.474	798.676
	Case 5.5	8267.760	242.443	3747.534
	Case 5.6	8079.843	878.319	2085.522

Cumulative production of methane, nitrogen and carbon dioxide has been calculated. The prediction was made for 30 years of production from 1/1/2017 to 1/1/2047. Simulation of injection has started in 1/1/2027 and lasted for 20 years in all cases.

Cumulative CH_4 production has been simulated. In the scenario, without ECBMR it is equal to 5388,790 MMscf. This amount will be compared to the rest of results to find how much extra methane has been produced with ECBM recovery.

4.2.3 Case 1 – 100% N_2 injection, Case 2 – 100% CO_2 injection results

Regarding the nitrogen ECBM technique, this injection into the coalbed reservoir should possibly induce methane production characteristics. Injection of 100% Nitrogen significantly increases (to 7734,405 MMscf) amount of gas produced. In theory, N_2 instead of adsorbing to the seam remains in the free phase and thus decreases CH_4 partial pressure. Latter allows methane to release for the further production.

When injected gas composition is changed to the 100% of CO_2 the result of the enhanced recovery is improved more. The mechanism for the CO_2 interaction with the coal seam is contrasting from the N_2 mechanism. CO_2 is adsorbed in greater quantities than methane thus replacing it and stimulating production. As far as this process causes such problems as matrix swelling, methane production should be probably reduced at some point. Petroleum Experts Software doesn't allow to observe that effect since it is not considered in the reservoir modelling and calculation in MBAL. Results of case 2 with pure CO_2 as an injection fluid are higher than in the case 1 with pure N_2. Cumulative methane production for the case 2 is equal to 7990.256 MMscf.

Table 19 illustrates a number of different gases produced during the injection period. The cumulative production of methane, nitrogen and carbon dioxide is calculated for cases 0, 1, and 2. These numbers show the amount of gas produced only during the injection period: since 01/01/2027 to 01/01/2047, where 01/01/2027 is the moment of injection implementation and 01/01/2047 is the ending point of prediction.

Table 19 – Gas produced during the injection period (01/01/2027 – 01/01/2047)

Case	*Gas produced during the injection period (01/01/2027 – 01/01/2047), MMscf*		
	CH_4	*N_2*	*CO_2*
Case 0	1474.79	–	–
Case 1	3820.41	2377.48	–
Case 2	4076.26	–	2070.34

It is essential to know if the amount of produced methane is lower than amount of N_2 or CO_2. Case 0 shows the methane production of 1474.79 MMscf which is simulated without reservoir stimulation. This amount considerably increases with the injection of N_2 or CO_2 in the cases 1 and 2 respectively. On the other hand, the amount of produced injected gas is relatively large.

Another important factor is the amount of gas adsorbed by the end of simulation of ECBMR: CH_4, N_2 and CO_2. It is calculated by the MBAL using the given properties of the Langmuir Isotherm for the reservoir. Thus, according to the isotherm, for the pressure of 700 psig, the amount of methane which is presented in the reservoir in the adsorbed state is equal to 18.84 SCF/ft3. Adsorbed amount of used in simulation gases is shown in Table 20.

Table 20 – Adsorbed in the seam gas by the end of simulation (01/01/2047), scf/ft3

Case	*Adsorbed in the seam gas by the end of simulation (01/01/2047), scf/ft3*		
	CH_4	*N_2*	*CO_2*
Case 0	8.84	–	–
Case 1	4.59	4.10	–
Case 2	4.11	–	12.31

Table 20 shows that the amount of adsorbed methane is decreasing from case 0 to case 2, meaning that more methane in total was desorbed and released from the coal in the case 2. Possibly that is because of the high amount of adsorbed to the coal CO_2 (3 times larger than CH_4) which replaces methane. N_2 is less adsorbing than CO_2 and adsorbed amount is approximately the same with CH_4. Despite that fact, it is necessary to remember that great amount of N_2 leaked to the production.

Possible CO_2 Sequestration process could be studied during the case with only CO_2 injection. CO_2 adsorption to the seam is high. During the 20 – year injection period, the specific volume of 12.31 scf/ft3 (IPM) remained in the coal. Short – time N_2 injection, performed with sequestration process, could prevent coalbed matrix from massive swelling. This option could be possible in more long – term perspective.

Hence, adsorption values allow to estimate the recovery factor (RF) which could be reached in the simulation:

- Case 1 – 0.757
- Case 2 – 0.782

There are some factors that effect on the results of the predictions results. One of them the matrix swelling effect because of CO_2, and the second is a too early breakthrough of injected gas. Literally, gas leakage to the production begins at the moment of the injection. Leaked to the production gas is separated at the surface and then re – injected to the seam.

4.2.4 Case 3 – N_2 – Alternating – CO_2 injection results

The results for the total cumulative production from 2017 up to 2047 are represented in Table 18 As in the previous cases, gas production during injected period (since 01/01/2027) is analysed.

Cumulative methane production is decreasing from case 3.1 to case 3.3. The later the CO_2 injection has been started, the more nitrogen and fewer CO_2 are produced. The largest amount of CH_4 is produced in the case 3.1. It has 25% of N_2 in production at the moment of the CO_2 injection. This gas is considered to be separated from the surface and then re – injected to the seam. This 25% of N_2 could be used as a limitation factor. This amount is sufficient to allow the significant increase in the methane production.

Sensitivity study in the case 3 showed that there is a tendency of decrease the CH_4 production with an increase of the period of N_2 injection, also causing to its larger breakthrough to the production. After that, injection of CO_2 becomes less effective, following the same tendency.

Likewise, it is necessary to pay attention to the adsorption characteristic. Later CO_2 injection is performed, more N_2 stays in the adsorbed form by the end of the simulation. That negatively affects the CO_2 adsorption volume. It could be noticed from the graph that if more CO_2 is adsorbed – less amount of CH_4 remain in the seam, increasing the recovery from the CBM reservoir.

More likely, after injection CO_2 replaces and releases both CH_4 and N_2 from the seam for production, thus decreasing the remained in the coal amount of these gases. These values are represented in Table 21.

Table 21 – Adsorbed in the seam gas by the end of simulation (01/01/2047), scf/ft3

Case	*Adsorbed in the seam gas by the end of simulation (01/01/2047), scf/ft3*		
	CH_4 01.01.2047	*CO_2 01.01.2047*	*N_2 01.01.2047*
case 3.1	4.41	10.05	0.45
case 3.2	4.55	7.40	1.15
case 3.3	4.56	4.76	1.99

Recovery factor for all cases is calculated and equals to:

- Case 3.1 – 0.766
- Case 3.2 – 0.759
- Case 3.3 – 0.757

Thus, Case 3.1 is the most efficient in the Case 3 simulations.

4.2.5 Case 4 – CO_2 – Alternating – N_2 injection results

Injection of CO_2 and subsequent injection of N_2 are considered in the case 4.

Cumulative production of CH_4, CO_2 and N_2 since the beginning of the simulation is represented in Table 18.

Case 4.3 shows best results in terms of cumulative production. At this case, the CO_2 injection was performed since 01/01/2027 to 09/01/2042 The behaviour of the graph, in this case, is opposite to the case 3. The amount of produced CO_2 increases with the prolonging of its injection period. More CO_2 is injected, less N_2 and CH_4 are produced.

Table 22 – Case 4. Adsorbed in the seam gas by the end of simulation (01/01/2047), scf/ft3

Case	*Adsorbed in the seam gas by the end of simulation (01/01/2047), scf/ft3*		
	CH_4 01.01.2047	*N_2 01.01.2047*	*CO_2 01.01.2047*
case 4.1	4.30	3.12	3.82
case 4.2	4.21	2.31	6.66
case 4.3	4.18	1.47	9.13

Table 22 shows adsorption data for the gases used in the simulation. The amount of adsorbed CO_2 increases with the duration of CO_2 injection period and decreases when N_2 injection starts. More CO_2 is adsorbed, less N_2 and CH_4 is adsorbed. It is replacing them from the seam, thus increasing their production. For the case 4.6, the amount of CO_2 adsorbed in the coal at the end of simulation is twice higher than the amount of CH_4 and almost 5 times higher than N_2 adsorbed.

According to the simulation data, the year of N_2 injection influences on how much CO_2 will be adsorbed onto the coal. These results, probably are not completely relevant, because swelling effect of CO_2 should've created unstable conditions for the injection gases and, also for the coalbed CH_4 production. Since IPM couldn't simulate that effect, CH_4 production increases directly as the amount of CO_2 adsorbed to the seam increases.

Calculated RF for the case 4 is estimated:

- Case 4.1 – 0.7719
- Case 4.2 – 0.7768
- Case 4.3 – 0.7781

4.2.6 Case 5 – Mixture injection

To ascertain the effect of the mixture of N_2 and CO_2 used for the ECBM case 5 was considered. Table 18 represents the produced amount of CH_4, N_2 and CO_2. Adsorbed in the seam gas by the end if the simulation is estimated in Table 23.

Table 23 – Case 5. Adsorbed in the seam gas by the end of simulation (01/01/2047), scf/ft3

Case	*Adsorbed in the seam gas by the end of simulation (01/01/2047), scf/ft3*		
	CH_4 01.01.2047	*N_2 01.01.2047*	*CO_2 01.01.2047*
case 5.1	3,59	4,33	1,99
case 5.2	3,78	3,36	4,04
case 5.3	4,00	2,33	6,16
case 5.4	4,29	1,22	8,39
case 5.5	3,54	4,67	1,29
case 5.6	3,88	2,85	5,09

In all scenarios suggested for that case, the amount of N_2 produced since 2027 is smaller than the amount of Methane. There is a tendency to equalise this amount with the increase of N_2 content in the mixture. In the case of 87% of N_2 in the injection gas, which is similar to the flue gas composition, the difference between N_2 and CH_4 produced becomes small, which is undesirable.

In the case 1, we don't observe this tendency. Possibly, the reason for that is the amount of CO_2 in the injection gas. As it could be observed from the graphs, cumulative production in case of 87% N_2 +13%CO_2 is higher than in the case of 100% N_2. CO_2 causes that stimulation effect on both, CH_4 and N_2 production.

4.2.7 Gas rates and cumulative production comparison for different simulated cases

Gas production rates for the best scenario in each simulation case are represented in Figure 26. There rates show total gas flow: CH_4 with N_2 and CO_2 together. It could be noticed that rate values are the highest in the case of mixture injection.

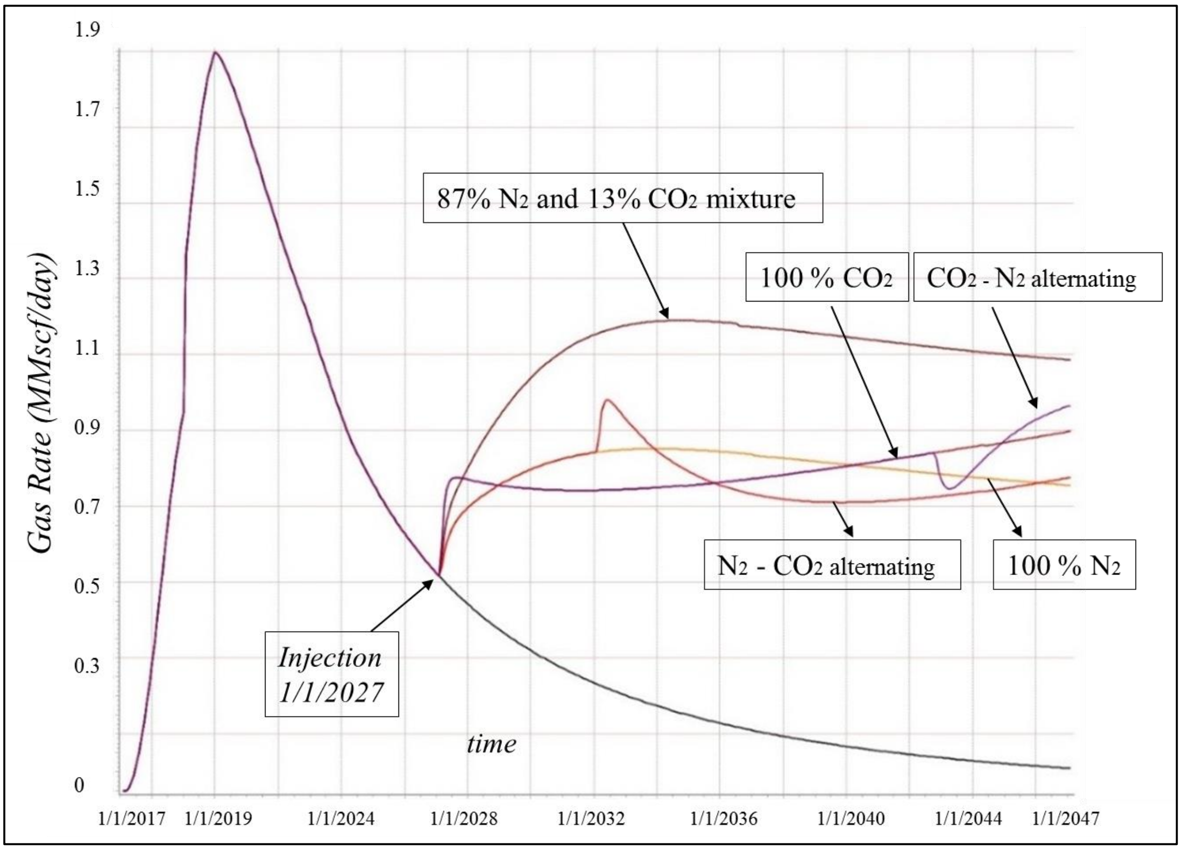

Figure 26 – Gas production rates for the best scenario in each simulation (Cases 5.5, 2, 4.3, 3.1, 1 and 0)

Possibly, production rate in case of 100% N_2 is firstly higher than for the case with 100% CO_2 injection. CO_2 injected in the seam goes through the 2 stages: firstly, it like any gas in the gas mixture, decreases the partial pressure of the other gas mixture components, thus triggering the CH_4 desorption. During that stage is adsorbs to the seam replacing CH_4 from the matrix. On the other hand, N_2 main goes only through the first stage as it is main mechanism of N_2 interaction with the coalbed methane. On the gas rates graph it could be observed that during the assumed 1st stage CO_2 injection case gas rate increases slower than in the N_2 injection case. Whereas, when adsorption process starts the curve line increases and in the end, shows the better production values.

The curves for simulated cumulative gas production data are represented in Figure 27.

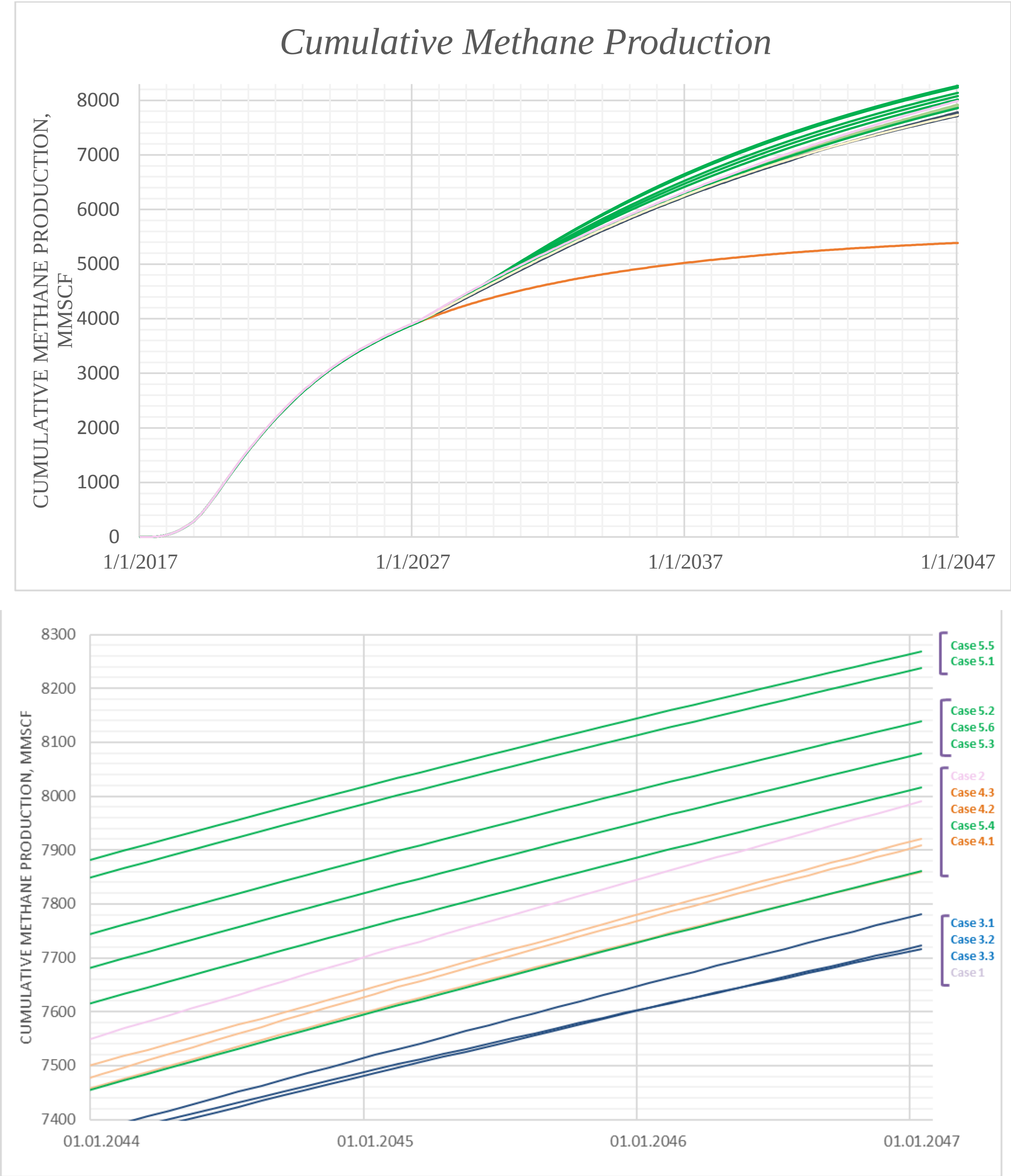

Figure 27 – Cumulative methane production – IPM

The red curve on Figure 27 describes original reservoir production. Parameters for this curve were determined as Case 0 in the table. Cumulative methane production rapidly increases during first 10 – 15 years, and after that, the line becomes more horizontal. The value of cumulative methane production by 01/01/2047 reached 5388,790 MMscf. (0.531 RF).

All cases of the ECBM recovery are represented on this graph. The difference in the cumulative production by the 01/01/2047 could be observed. Almost all scenarios from the case 5 have the highest results among other cases. Case 4 is in the middle, and case 3 are the less efficient regarding production. Variation of the results is noticeable but not significant. The difference between the least and the most efficient scenario is equal to 0.0554.

The highest cumulative production of methane is reached in the case 5.5 when flue gas composition was injected to the seam. Recovery factor, in that case, is equal to 0.809, and that is 27.8% more than the natural primary recovery of the case 0.

Nevertheless, the smallest cumulative methane production from all the cases of enhancing recovery provide the increase of the recovery factor by 0.226.

Figure 24 illustrates the recovery factor that can be reached by the enhanced recovery application.

Table 24 – Recovery factor for all simulation cases

<table>
<tr><th colspan="9">recovery factor, fraction</th></tr>
<tr><th>case 0</th><th>case 1</th><th>case 2</th><th colspan="2">Case 3</th><th colspan="2">Case 4</th><th colspan="2">Case 5</th></tr>
<tr><th>no injection</th><th>N_2 injection</th><th>CO_2 injection</th><th colspan="2">N_2 and CO_2 injection</th><th colspan="2">CO_2 and N_2 injection</th><th colspan="2">N_2+CO_2 mixture injection</th></tr>
<tr><td rowspan="6">0,531</td><td rowspan="6">0,757</td><td rowspan="6">0,782</td><td rowspan="2">case 3.1</td><td rowspan="2">0,7660</td><td rowspan="2">case 4.1</td><td rowspan="2">0,7719</td><td>case 5.1</td><td>0,8094</td></tr>
<tr><td>case 5.2</td><td>0,7996</td></tr>
<tr><td rowspan="2">case 3.2</td><td rowspan="2">0,7588</td><td rowspan="2">case 4.2</td><td rowspan="2">0,7768</td><td>case 5.3</td><td>0,7875</td></tr>
<tr><td>case 5.4</td><td>0,7722</td></tr>
<tr><td rowspan="2">case 3.3</td><td rowspan="2">0,7581</td><td rowspan="2">case 4.3</td><td rowspan="2">0,7781</td><td>case 5.5</td><td>0,8124</td></tr>
<tr><td>case 5.6</td><td>0,7939</td></tr>
</table>

4.3 CMG Simulation Results

4.3.1 Primary production

The model in CMG was developed as it was explained in the methodology chapter.

Considered cases were predicted from 1/1/2017 until 1/1/2047.

The simulation of the primary production shows that gas rate behaviour predicted by CMG is different from the results of IPM. Possible explanation for is that IPM considers ESP to be used, while CMG does not. The cumulative production is almost the same, but the curves patterns are different. In IPM ESP is installed to improve the well performance at the dewatering stage. A considerable amount of water was produced with this method. That possibly causes the larger pressure drop and allows more gas to desorb from the seam and be produced.

Gas and water rate curves are represented in Figure 28. The peak of the gas rate curve is smoother than in IPM case, and the maximum gas rate from 2 production wells is 0.75 MMscf/day against the 1.9 MMscf/day in the IPM case.

To match models and to make them more similar in initial conditions, it was decided to reduce the Initial amount of water in place in CMG model by the half. That would possibly compensate that effect from the ESP pump. Curves for the 50% initial water case are represented in Figure 28. Gas production starts almost from the gas rate maximum values. New gas rate from 2 production wells became 1.61 MMscf/day. That case is considered as Case 0 for the further investigation.

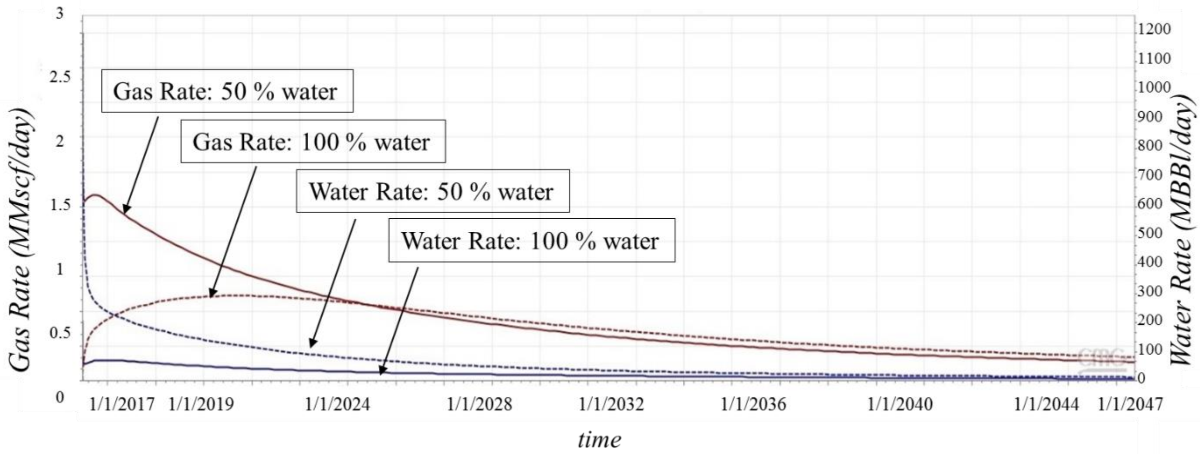

Figure 28 – Gas and water rate curves for cases with 100% and 50% of initial water in place

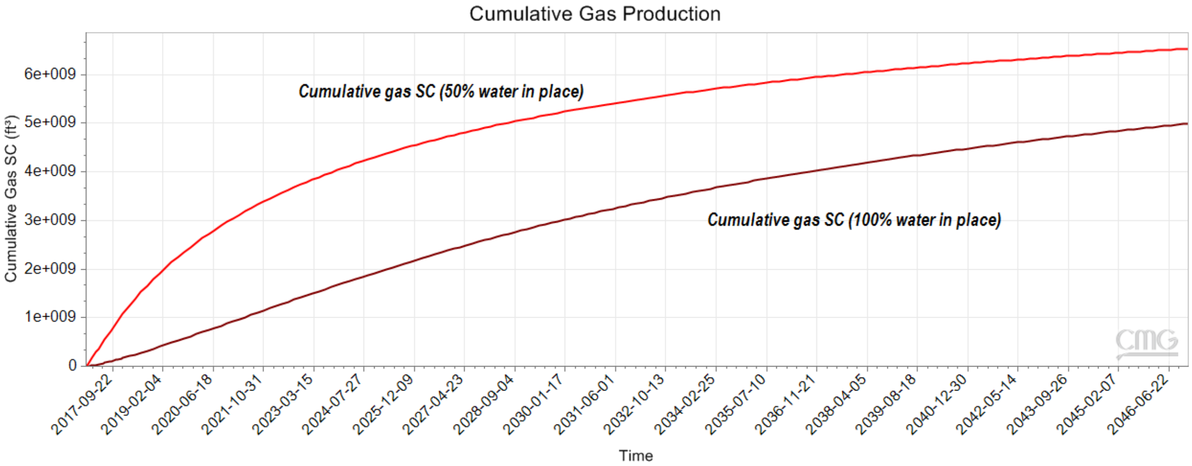

Figure 29 – Cumulative production: 50% water in place and 100% water in place situations

Cumulative gas production has slightly increased and became 4546.32 MMscf. This amount is equal to the 54.97 % Recovery. It is shown in Figure 29.The distribution of the gas saturation during the production period is visualised in Figure 30. The most amount of water has been released during the first years of primary recovery. That allowed to achieve good gas production values. It could be noticed that gas saturation drastically increases during the first ten years of production. Perhaps that is because of the dewatering period. However, since 2027 this growth remains very slow.

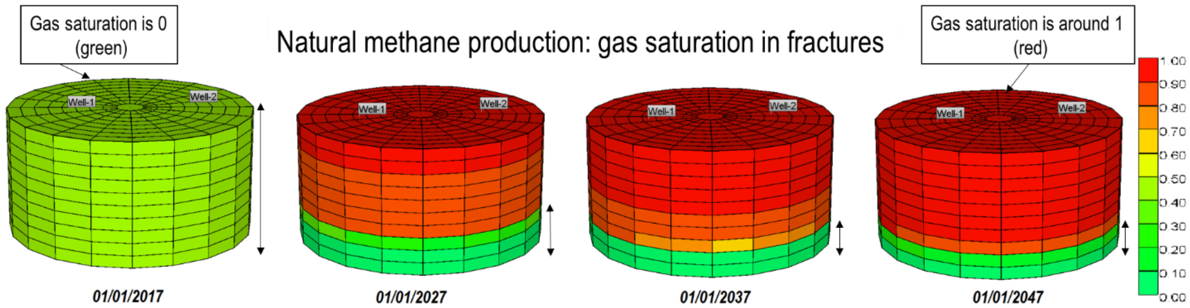

Figure 30 – Gas saturation in the fracture. From left to right:2017, 2027, 2037, 2047

4.3.2 General Data

Cumulative production of CH_4, CO_2 and N_2 at the end of 1/1/2047 are collected in Table 25.

Table 25 – Cumulative production of CH_4, CO_2 and N_2 at the end of 1/1/2047

Type of injection	*Case*	*Cumulative production, 1/1/2047, MMscf*		
		CH_4	*CO_2*	*N_2*
no injection	Case 0	5690.000	–	–
N_2 injection	Case 1	5817.419	–	2897.181
CO_2 injection	Case 2	5957.976	3543.224	–
N_2 and CO_2 injection	Case 3.1	5924.703	2145.747	969.850
	Case 3.2	5922.024	1161.466	1697.110
	Case 3.3	5917.756	398.344	2215.100
CO_2 and N_2 injection	Case 4.1	5971.874	1680.141	1593.185
	Case 4.2	5970.842	2511.482	948.076
	Case 4.3	5973.271	3348.040	397.589
N_2 and CO_2 mixture injection	Case 5.1	6045.547	506.339	3798.115
	Case 5.2	5959.559	1038.754	2845.388
	Case 5.3	5969.196	1607.235	1897.369
	Case 5.4	5940.159	2173.623	941.718
	Case 5.5	6059.944	325.095	4125.961
	Case 5.6	5987.339	1324.033	2375.529

4.3.3 100% N_2 injection (Case 1) and 100% CO_2 injection (Case 2) Results

Production behaviour of the reservoir in the CMG model is very comparable to the one in the IPM model. The 100% N_2 and 100 % CO_2 injection results are given in the table.

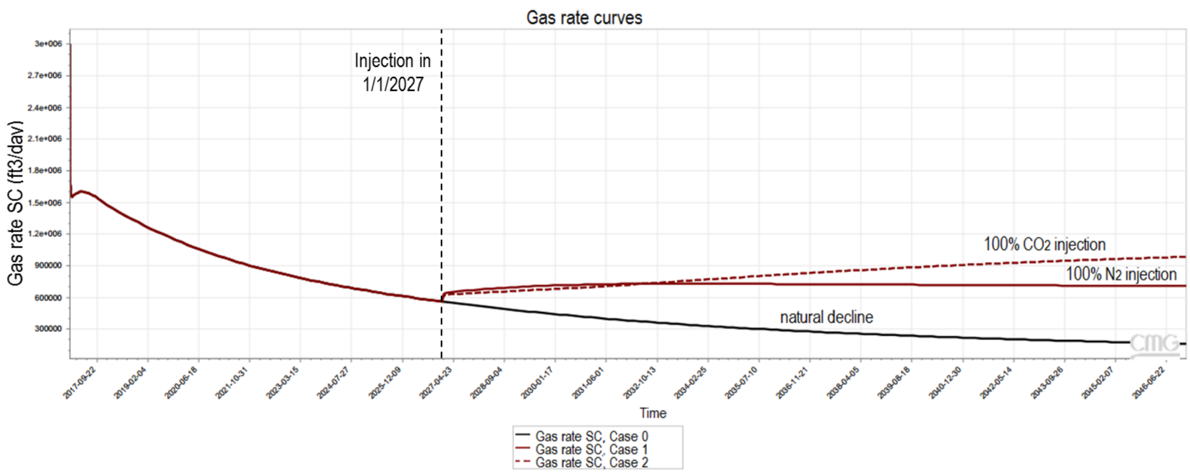

Figure 31 – Gas production rates (Case 0, Case 1, Case 2)

Figure 31 represents production gas rate increase after the injection year. 100% CO_2 injection have a greater effect on the production gas rate curve than 100 % N_2 injection case. However, these gas curves show total gas rates: CH_4 with the injected gases breakthrough to the production wells. That illustrates that N_2 and CO_2 breakthrough take place right after the injection implementation.

Table 26 – Adsorbed in the seam gas by the end of simulation (01/01/2047), scf/ft3

Case	*Adsorbed in the seam gas by the end of simulation (01/01/2047), scf/ft3*		
	CH_4	*N_2*	*CO_2*
Case 0	8.35	–	–
Case 1	7.91	3.26	–
Case 2	7.81	–	9.42

It could be noticed that amount of methane remained in the seam after the production period differs very slightly from the Case 0 value. These results are opposite to the IPM results.

As it was mentioned in Table 26, values for case 1 and 2 were 4.59 and 4.11 scf/ft3 respectively. On the other hand, the amount of adsorbed N_2 and CO_2 remained in the seam by the end of simulation period is higher in cases made in IPM.

Methane mole fraction curve for the matrix goes slightly higher in than the same curve for the fracture because the volume of the matrix is greater that the fracture volume.

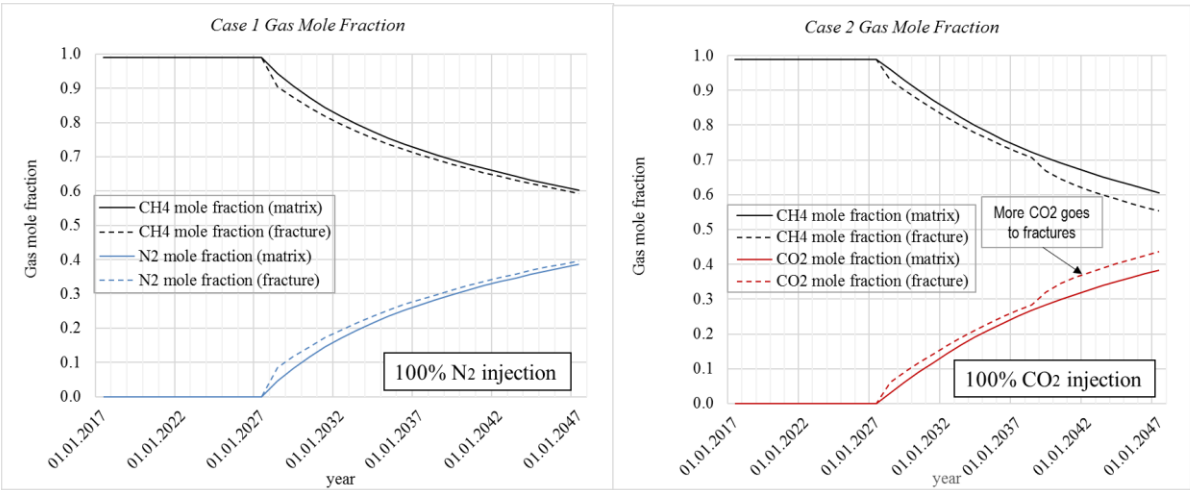

Figure 32 – Gas mole fraction, case 1 and case 2

Consider Case 2 (IPM) and Case 2 (CMG). The main difference here is that in the case of IPM model, CH_4 is easily removed by the adsorbing CO_2. CO_2 has a high affinity for adsorption, and it replaces CH_4 and after that stays in the seam.

Amount of CO_2 adsorbed in the seam in 1/1/2047 is much less than in IPM case. That could inform that matrix swelling effect occurs there. That could be partly confirmed by the Figure 32. The right part of the figure describes case 2. It could be observed that there is a change in the behaviour of CO_2 and CH_4 fracture curves since the 2038 year. More CO_2 starts to go to the fractures. Probably, the amount of CO_2 injected to the seam has caused coal swelling. CO_2 as a free gas occupies more space. This effect does not present on the N_2 fracture curve for case 1. Therefore, CO_2 adsorption does not give an expected effect because it could close micropores and prevent CH_4 from the further production. Thus, a large part of the injected gas goes to the production wells. The amount of produced CH_4, N_2 and CO_2 in moles are represented in Figure 33. While adsorption characteristics of CO_2 are the highest, it also has a highest gas breakthrough value relatively to the case with 100 % N_2 injection.

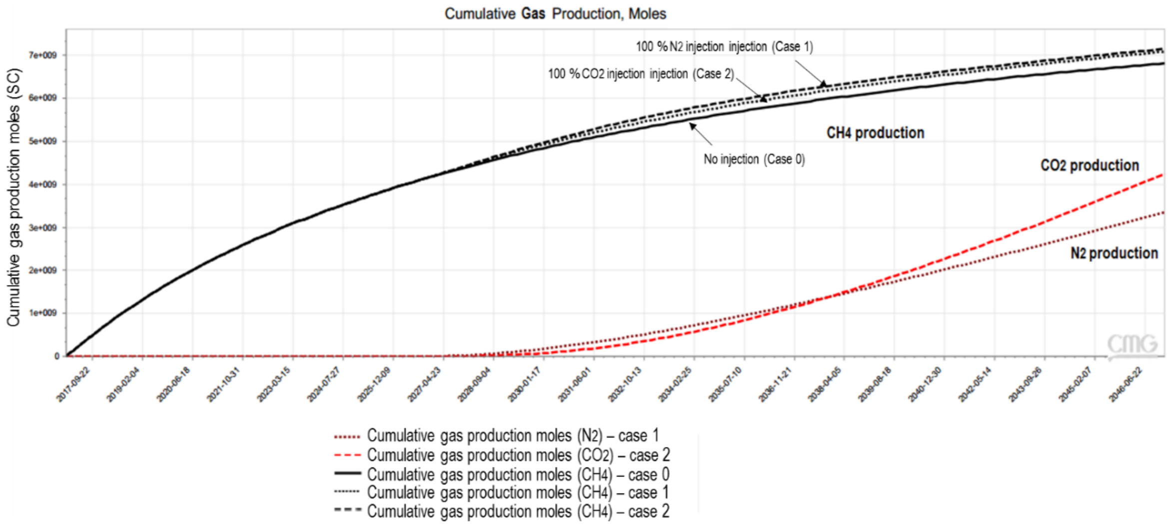

Figure 33 – Cumulative gas production, moles SC. Case 0, 1, 2

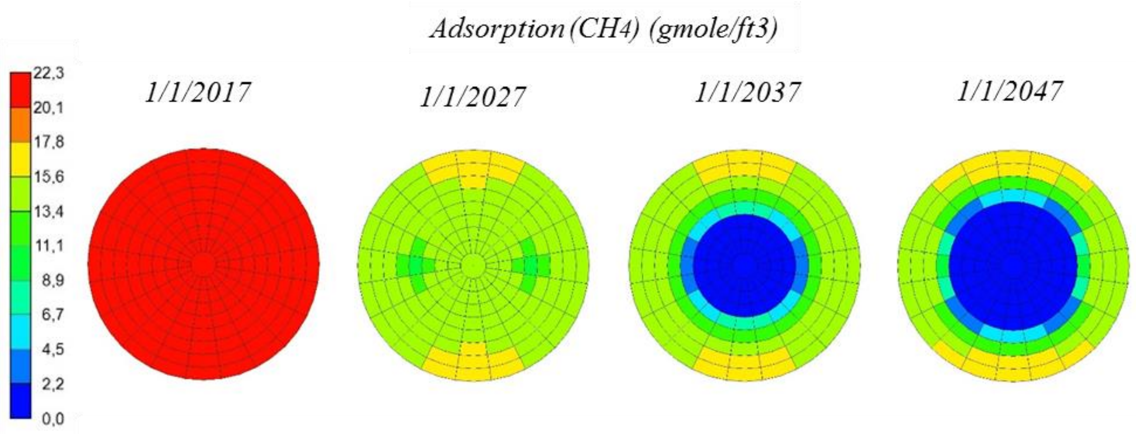

Figure 34 – Adsorption process. Case 2

The visual presentation of the methane desorption process is shown in Figure 34. First of all, it could be noticed that reservoir model is not homogeneous. Even before the injection period starts, CH_4 desorption was not fully distributed through the reservoir (e.g. yellow margins). It concentrated mostly near production wells. Since injection started (3rd image), CO_2 replaced the central part of the reservoir and occupied the regions near the production wells, thereby going directly to the production wells and blocking CH_4 production. However, increase in cumulative methane production is not as significant as in IPM case. However, in the case of 100%, CO_2 injection recovery is still higher than in the case of 100% N_2 injection.

A recovery factor of the cases 1 and 2 is:

- Case 1 – 0.5620
- Case 2 – 0.5756

4.3.4 Case 3: N_2 - CO_2 alternation injection

Adsorbed amount of the gases used in the simulation is estimated and presented in Table 27

Table 27 – Adsorbed in the seam gas by the end of simulation (01/01/2047), scf/ft3

Case	*Adsorbed in the seam gas by the end of simulation (01/01/2047), scf/ft3*		
	CH_4 01.01.2047	*CO_2 01.01.2047*	*N_2 01.01.2047*
case 3.1	7.88	7.99	0.37
case 3.2	7.90	6.60	0.75
case 3.3	7.92	4.81	1.25

Adsorbed in the seam amount of CH_4 summarised in Table 27 stays high, as in the cases 1 and 2. In Figure 35 for the case 3.1, it could be noticed that values on the CO_2 adsorption curve increase during the time. N_2 adsorption values, in turn, slightly increase until the data of CO_2 injection. Since then N_2 with CH_4 are replaced by the CO_2. Also, that fact could be demonstrated by Figure 37 that after the end of N_2 injection period it is still produced from the seam until the end of the simulation period. Figure 35, Figure 36 describe adsorption of CO_2, N_2, and CH_4 in the seam. N_2 injection with CO_2, consequently, becomes more efficient than the case of only N_2 injection.

Injected CO_2 replaces both CH_4 and N_2 from the seam and also distributes N_2 already contained in the coal, closer to the borders of the reservoir. In other words, N_2 injected in the first order prepares the reservoir and makes seam ready for the CO_2 injection, decreasing methane partial pressure and adsorbing to the coal. Then an injection of CO_2 with much higher adsorption affinity than methane allows producing more methane.

The general tendency of the N_2 - CO_2 alternating injection is that: the shorter is the N_2 injection period, the better would be CH_4 recovery. One of the possible reason for that is that the shorter is that period – less amount of N_2 is produced. N_2 has a great affinity to be produced with the CH_4, consequently cutting its recovery. It could be seen from the Figure 37 that the case with the relatively highest recovery value – case 3.1 (N_2 injection in 2027, CO_2 injection in 2032) – has the lowest amount of produced N_2. However, it has a high amount of produced CO_2 (Figure 38).

The other thing that could be observed from the Figure 36 is that CH_4 mole decline curve could be divided into 2 periods: N_2 injection, when only CH_4 and N_2 are on the seam and the 2^{nd} period, when CO_2 injection starts and CH_4, CO_2 and N_2 occur in the seam. It could be noticed that during the 1^{st} period only N_2 effects the CH_4 decline curve and it has more rapid slope than for the second period when both CO_2 and N_2 affect the CH_4 concentration in the seam. That could indicate that during the second – period main mechanism of the gas interaction is preferential adsorption and as it was described previously: N_2 has 1 stage mechanism of interaction with CH_4 (mostly partial pressure reduction) and CO_2 has 2 – stage mechanism (both pressure reduction and adsorption).

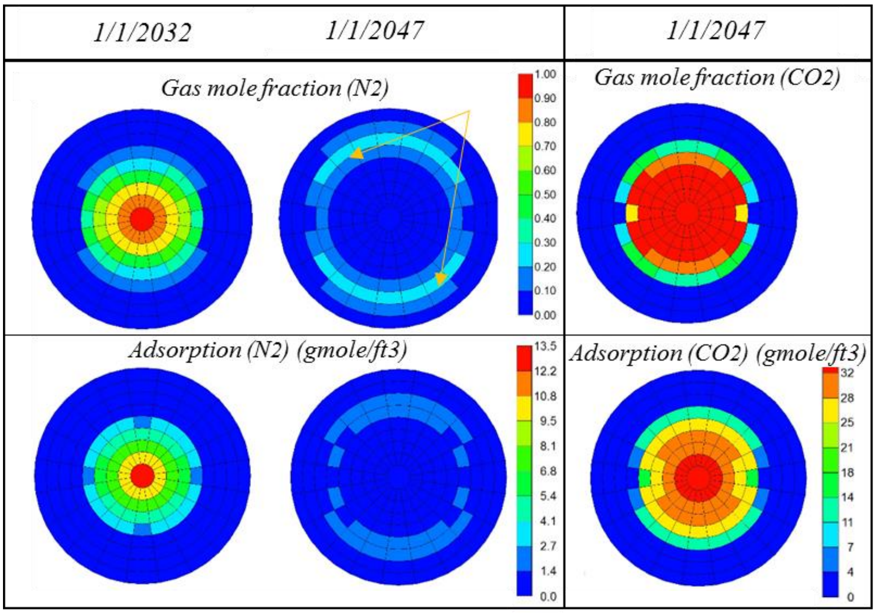

Figure 35 – Gas mole fraction and adsorption patterns Case 3.1

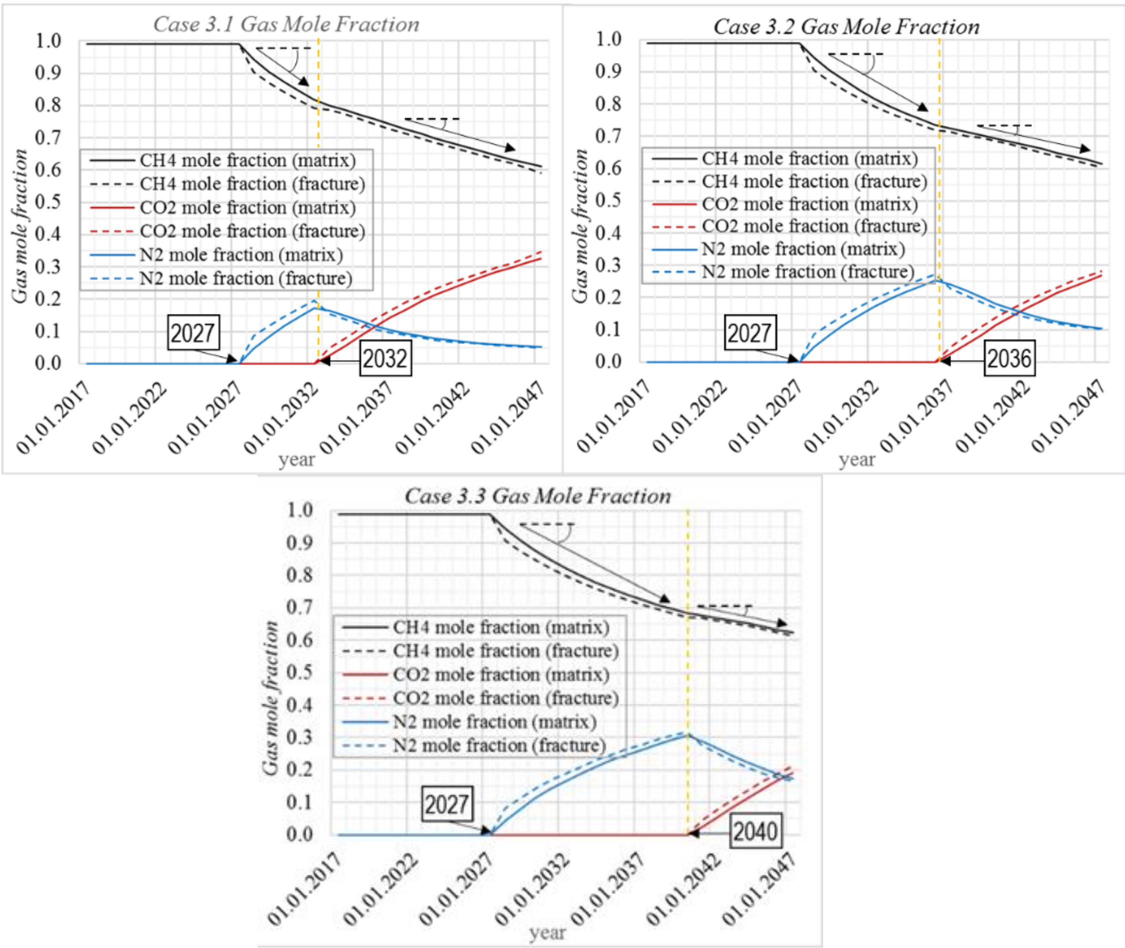

Figure 36 – Gas mole fraction. Summary. Case 3

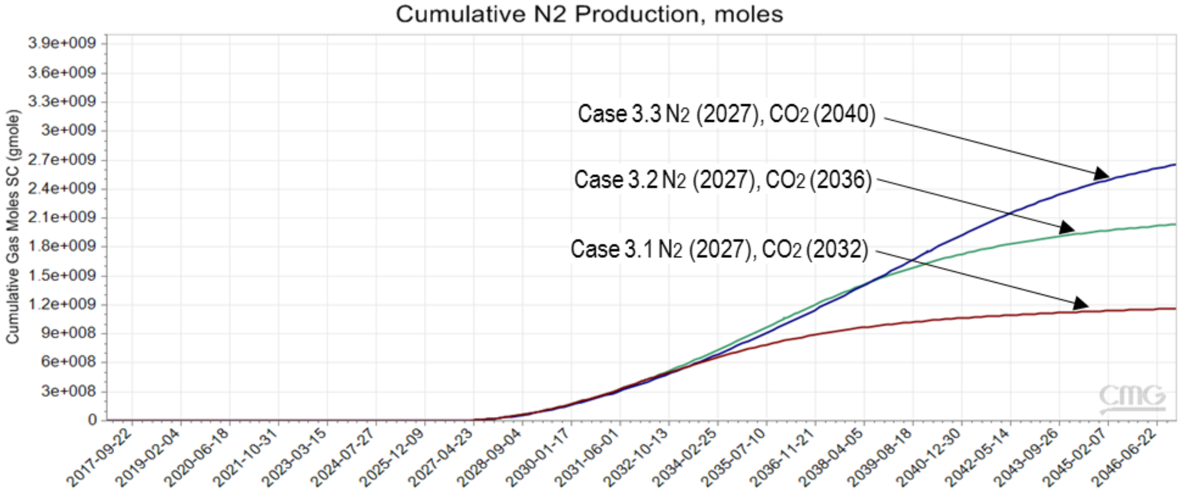

Figure 37 – N2 cumulative production, N2 - CO2 alternating injection

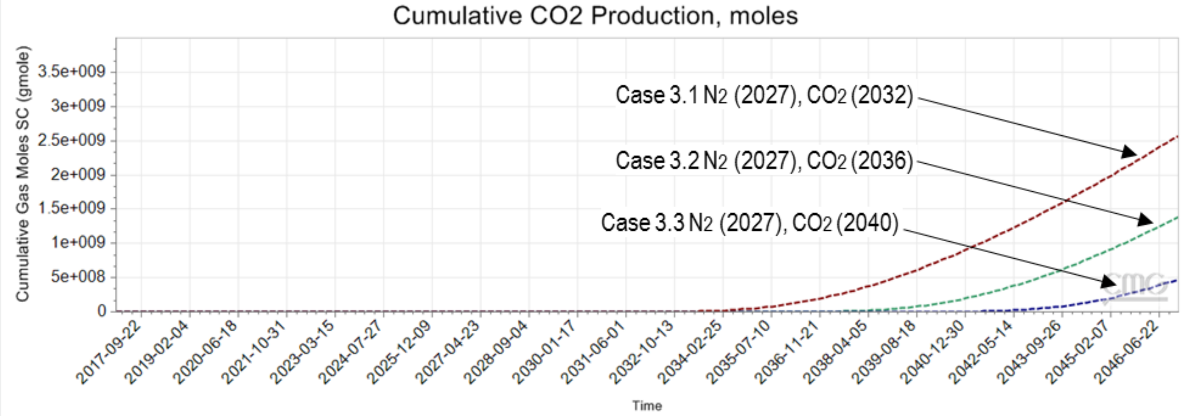

Figure 38 – CO2 cumulative production, N2-CO2 alternating injection

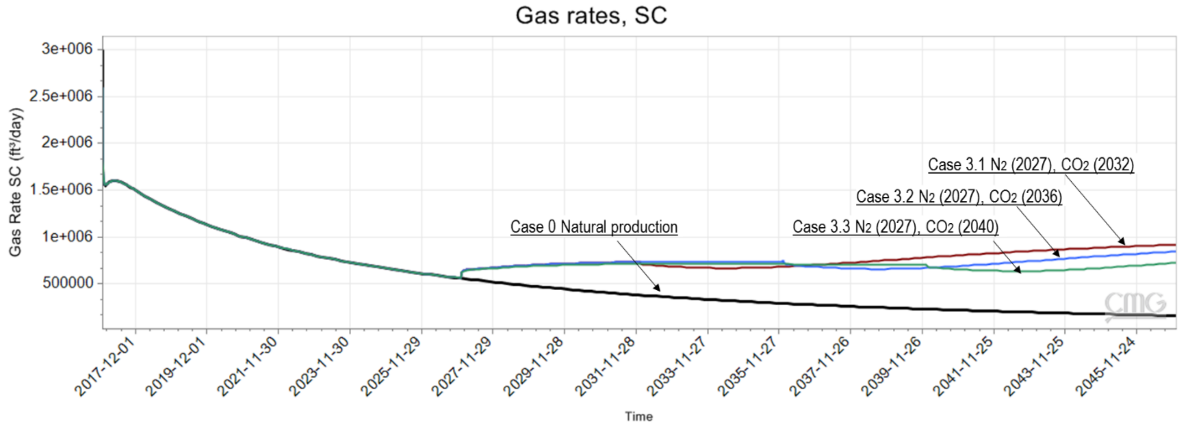

Figure 39 – Gas rates. N2 - CO2 alternating injection

Gas rates for all scenarios in the case 4 shows that the highest production rates occur in the case 3.1. (Figure 39). In general, production behaviour tendency for the case 3 is almost the cases in IPM in a way that case 3.1 has the highest amount of cumulative methane production among other scenarios in that case. Estimated recovery factor for case 3 is:

- Case 3.1 – 0.5724
- Case 3.2 – 0.5721
- Case 3.3 – 0.5717

4.3.5 Case 4: CO_2 - N_2 alternation injection

Adsorbed amount of gases in case 4 is represented in Table 28.

Table 28 – Adsorbed in the seam gas by the end of simulation (01/01/2047), scf/ft3

Case	Adsorbed in the seam gas by the end of simulation (01/01/2047), scf/ft3		
	CH_4	CO_2 01.01.2047	N_2 01.01.2047
case 4.1	7,81	2,52	2,58
case 4.2	7,80	4,20	2,05
case 4.3	7,78	6,35	1,35

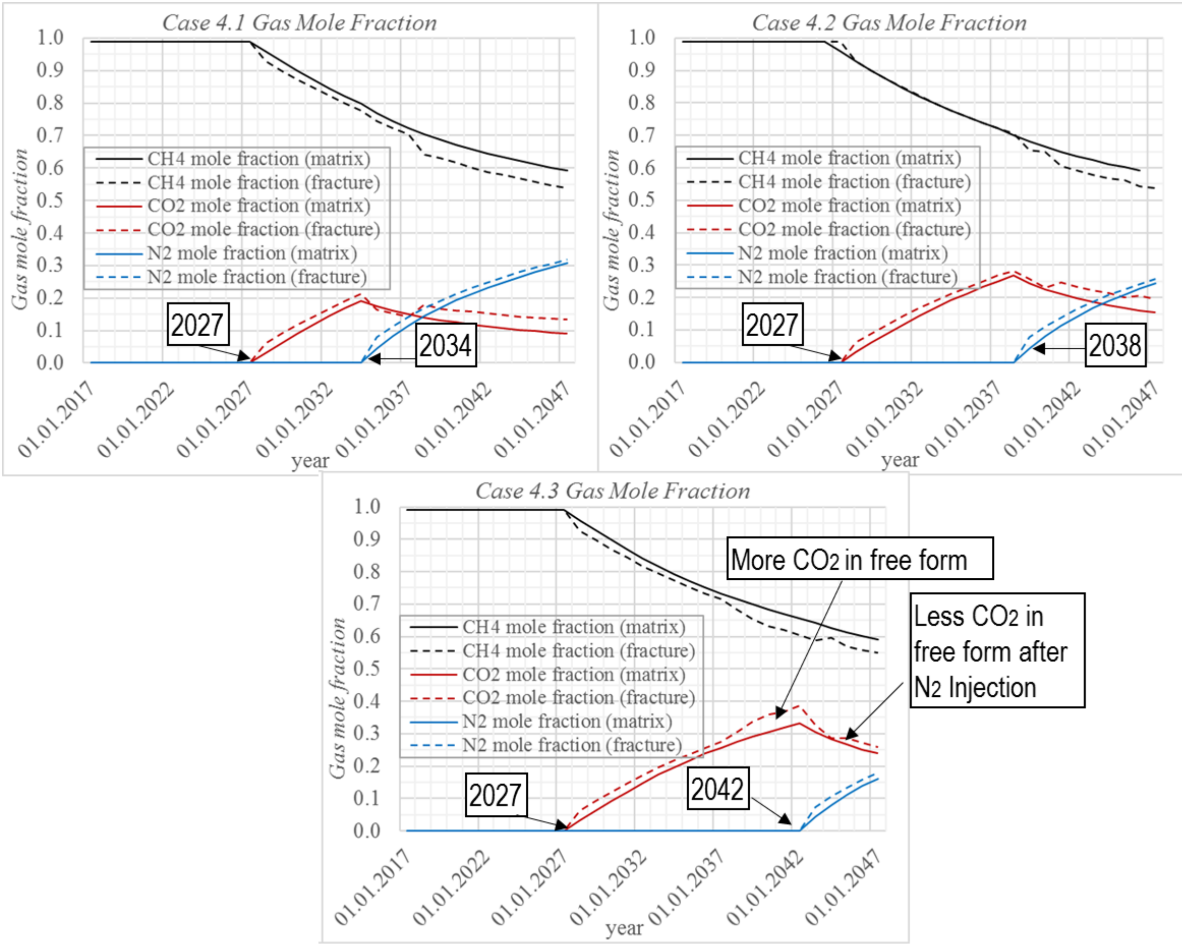

Figure 40 – Gas mole fraction. CO_2 - N_2 alternating injection

The best scenario among the case 4 is the case 4.3. The highest amount of CO_2 (6.35 scf/ft3) and the lowest amount of N_2 (1.35 scf/ft3) is adsorbed to the seam in this case. CO_2 adsorbs from the seam less readily during the N_2 injection.

From Figure 40 it could be noticed that during the N_2 injection in all cases from group 4 CO_2 mole fraction in the fracture is increasing. In the case 4.3 it reaches 0.38, while in the case 3 this phenomenon does not occur and this curve goes slightly lower. The possible reason for that is the CO_2 swelling effect that occurs similarly to the case 2 (100% CO_2 injection), where after around ten years the concentration of the CO_2 reaches a certain value that induces coal swelling.

Thus, more CO_2 remains in the free gas phase. After the N_2 injection implementation, that effect is reduced, but there is still a certain amount of CO_2 in the fractures because of its desorption during the inert gas injection. Injection gases adsorption patterns are represented in Figure 42.

For CO_2 - N_2 alternation injection general tendency is that the longer in performed CO_2 injection, better CH_4 recovery wold be received. CO_2 injection releases a large part of CH_4, and after that N_2 sweeps, the remained after that CH_4.

In case 3 first injection is N_2, and during the period of its injection it adsorbed to the empty pores, left from the methane desorption. As it was shown earlier during the later injection of CO_2, both CH_4 and N_2 were replaced by CO_2 because of less adsorption affinity. In case 4 the second injection is N_2. CO_2 and CH_4 are already absorbed in the seam. Theoretically large part of adsorbed CO_2 remains in the seam, and that allows N_2 to affect more directly on the CH_4 still left in the seam after CO_2 injection.

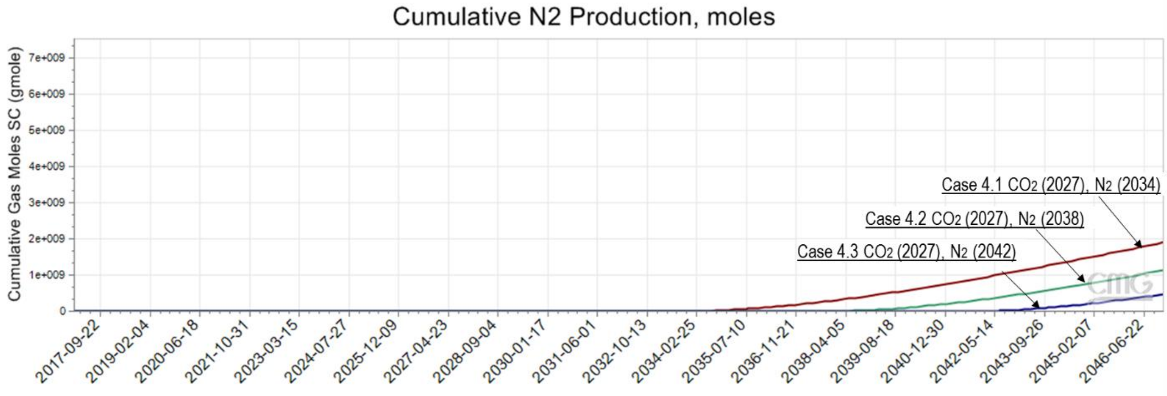

Figure 41 – Cumulative N_2 production. CO_2 - N_2 alternating injection

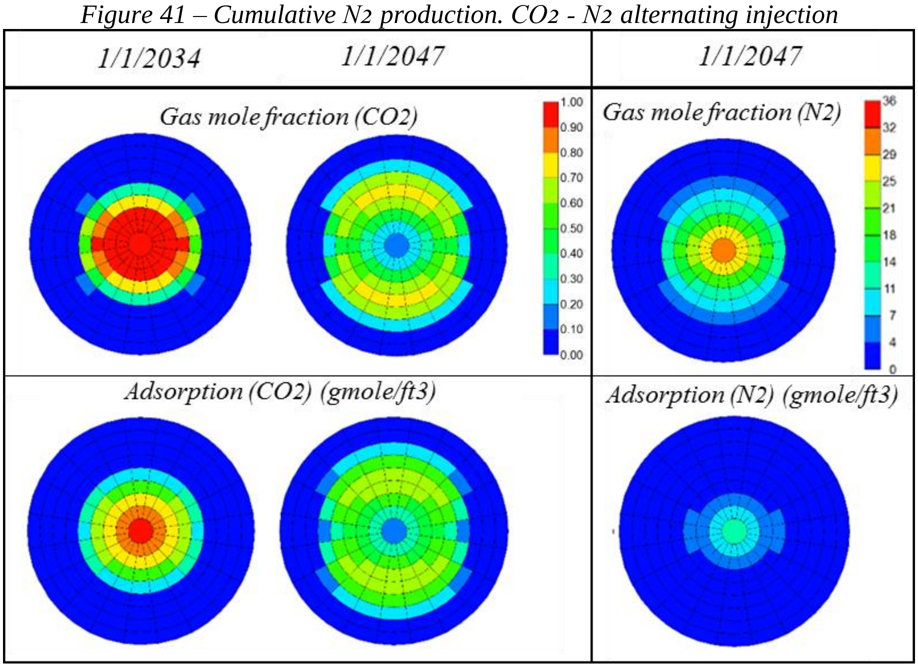

Figure 42 – Adsorption and molar fracture change with time, visualisation

Production rates are shown in Figure 44. Methane rates are enhanced in all scenarios of case 4. CH_4 production rates increase more with the CO_2 injection and start to decrease slightly during the N_2 injection. The highest rates were reached in the case 4.3 – around 1 MMscf/day.

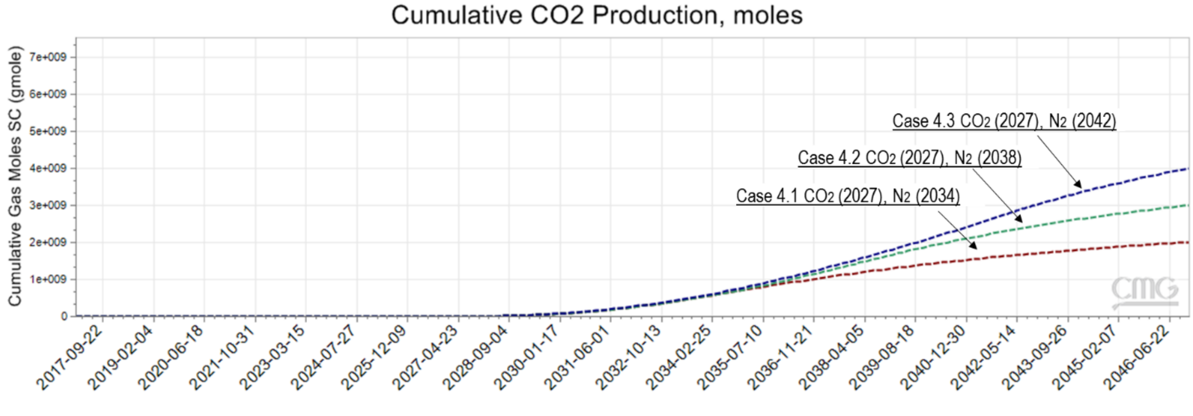

Figure 43 – Cumulative CO_2 production. CO_2 - N_2 alternating injection

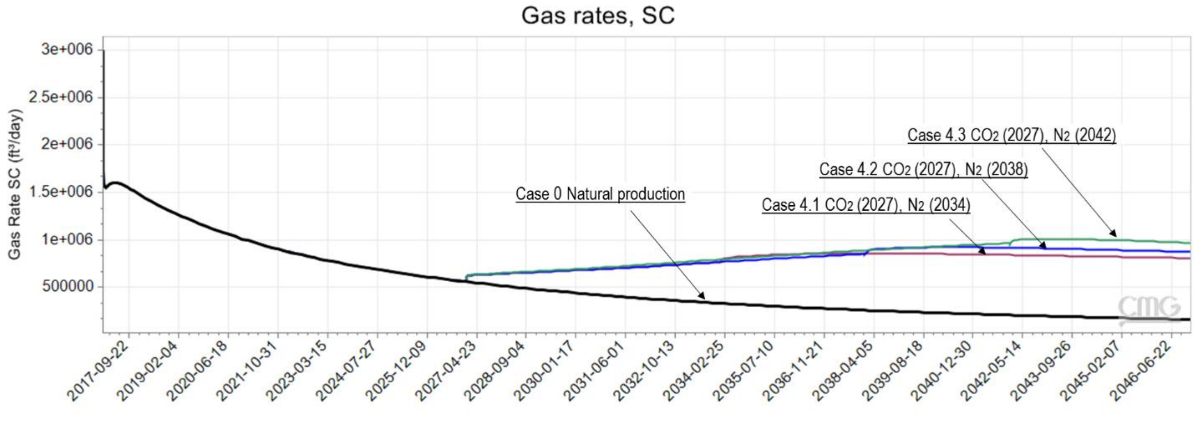

Figure 44 – Gas rates. CO_2 - N_2 alternating injection

Case 4.3 results show that during the CO_2 injection its adsorption to the seam was increasing and reached relatively high values. It decreased during the N_2 injection period because the partial pressure of CO_2 as far as a CH_4 is decreasing and that allows it to come to the fractures and be produced. As in the case 3, it could be concluded that to increase CH_4 production it is necessary to prolong CO_2 injection period, but it is very important to schedule it before the N_2 injection because that combination gives the highest result among all alternation cases.

Recovery factors for the case 4 are equal to:

- Case 4.1 – 0.5769;
- Case 4.2 – 0.5768
- Case 4.3 – 0.5771

4.3.6 Case 5 –Mixture injection

As in the IPM model, case 5.5 shows the highest results in the cumulative CH_4 production (Table 25). Simulated adsorption characteristics for all scenarios are shown in Table 29 and in Figure 45. In the case 5.5 CO_2 adsorption in the seam is the lowest among the Case 5 scenarios – 1.12 scf/ft3 and N_2 adsorption is the highest – 3.84 scf/ft3

Table 29 – Adsorbed in the seam gas by the end of simulation (01/01/2047), scf/ft3

Case	*Adsorbed in the seam gas by the end of simulation (01/01/2047), scf/ft3*		
	CH_4 01.01.2047	*CO_2 01.01.2047*	*N_2 01.01.2047*
case 5.1	7.69	1.72	3.53
case 5.2	7.83	3.39	2.65
case 5.3	7.81	5.00	1.77
case 5.4	7.86	6.62	0.90
case 5.5	7.66	1.12	3.84
case 5.6	7.78	4.20	2.20

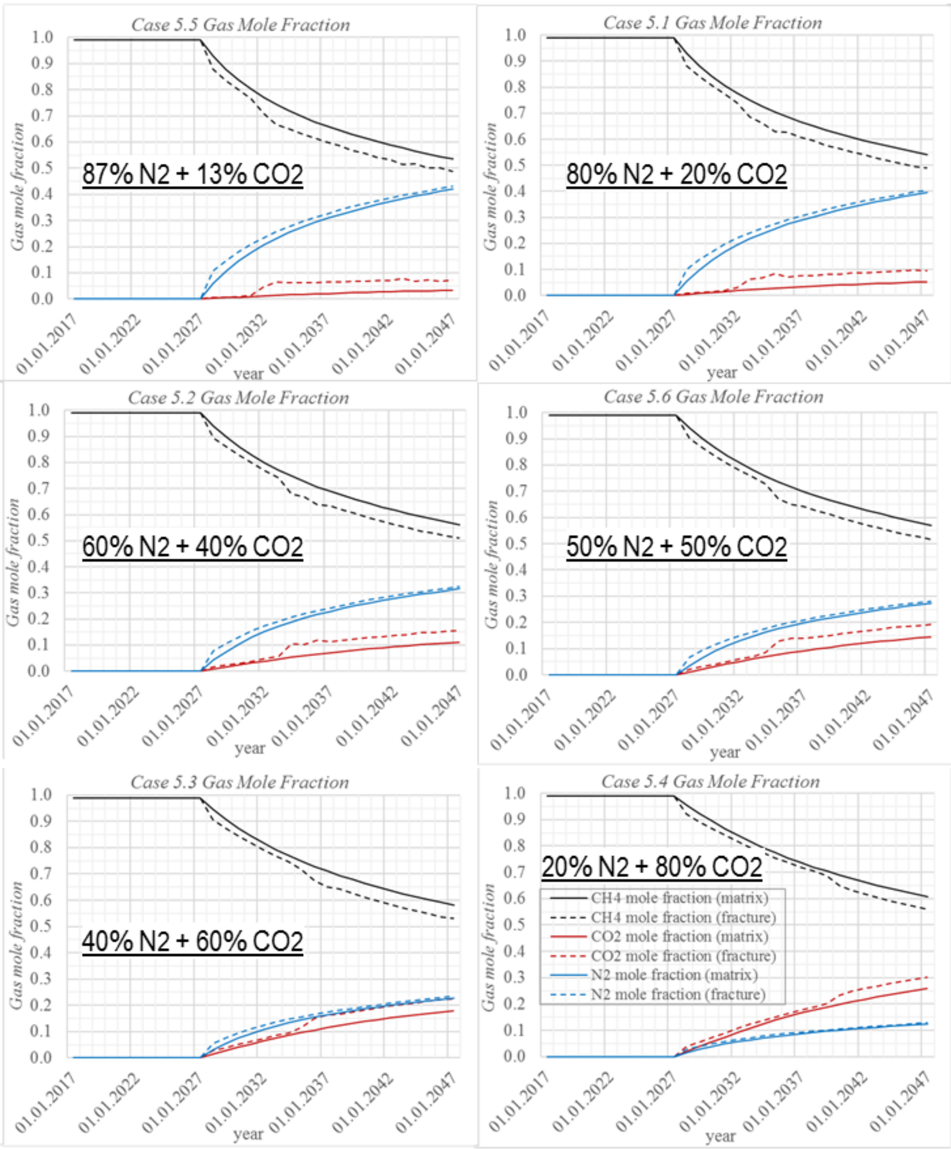

Figure 45 – Case 5. Gas mole fraction

The order of cases on Figure 45 was made in the way that the first picture represents the case with the highest amount of N_2 in the injected gas (87%) and the last with lowest (20%). Case 5.5 showed the highest results. The lowest amount of CO_2 and highest amount of N_2, in this case, could also be noticed from this figure. Regarding produced gas, Figure 46 represent that the N_2 breakthrough to the CH_4 production increases with increasing the % of CH_4 in the injection mixture. The opposite trend for CO_2 production is demonstrated in Figure 47.

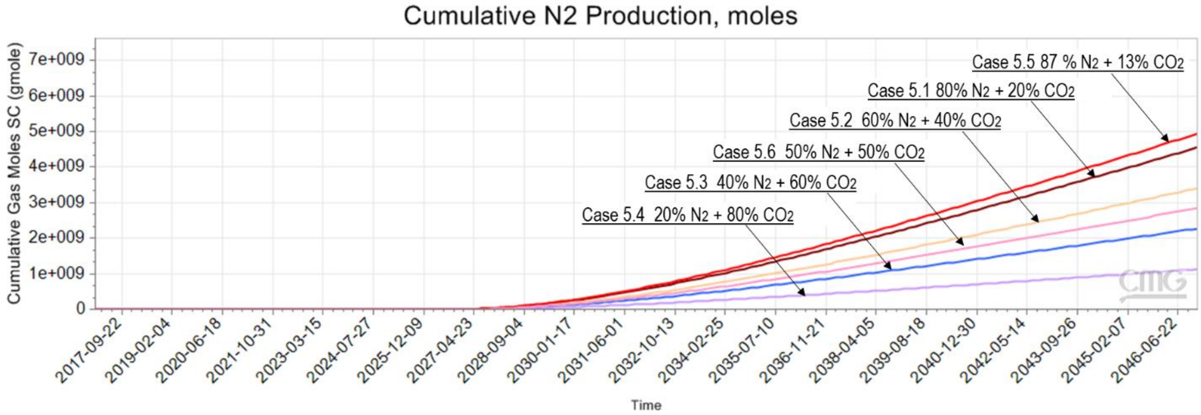

Figure 46 – Cumulative N_2 production. Mixture Injection

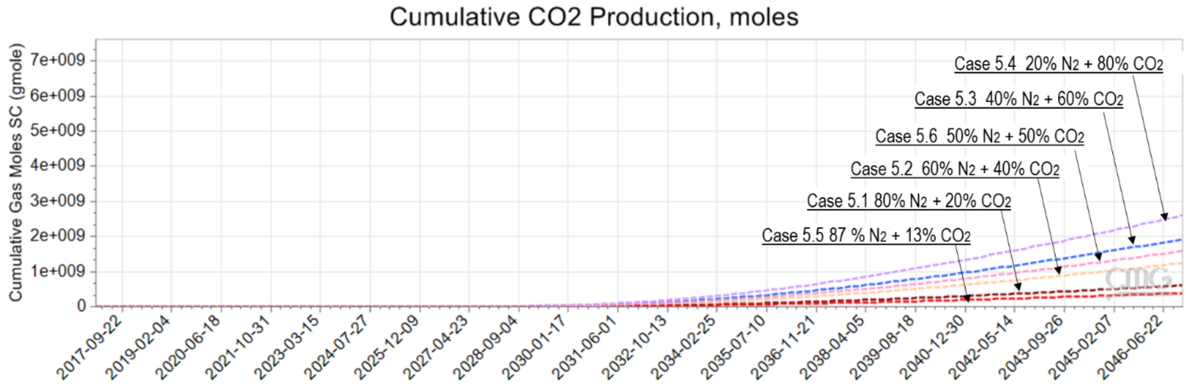

Figure 47 – Cumulative CO_2 injection. Mixture Injection

Thus, demonstrated results are possibly caused by two main tendencies:

- Reduced amount of CO_2 in the injection fluid allows preventing massive coal swelling or gas trapping in the seam. Also, a lower amount of CO_2 goes into the production.
- Less amount of N_2 would breakthrough to the production if the % of N_2 in the injection gas is reduced.

However, simulation results showed that the optimal combination of N_2 and CO_2 is as in the flue gas: 87% of N_2 and 13% of CO_2. An interesting fact is that 100% N_2 injection is less efficient than this scenario, recovery factor is 0.562. While recovery factor for the case 5:

- Case 5.1 – 0.5841;
- Case 5.2 – 0.5758;
- Case 5.3 – 0.5767;
- Case 5.4 – 0.5739;
- Case 5.5 – 0.5855;
- Case 5.6 – 0.5784.

4.3.7 Recovery results CMG

Table 30 contains recovery factors for all simulated cases. The best case regarding recovery is Case 5.5 with flue gas composition used as an injected gas.

Difference of the best case from the case 0 is only 3.6%

Table 30 – Recovery factor for all simulated in CMG cases

<table>
<tr><th colspan="9">recovery factor, fraction</th></tr>
<tr><th>Case 0</th><th>Case 1</th><th>Case 2</th><th colspan="2">Case 3</th><th colspan="2">Case 4</th><th colspan="2">Case 5</th></tr>
<tr><th>no injection</th><th>N2 injection</th><th>CO2 injection</th><th colspan="2">N2 and CO2 injection</th><th colspan="2">CO2 and N2 injection</th><th colspan="2">N2+CO2 mixture injection</th></tr>
<tr><td rowspan="6">0.549</td><td rowspan="6">0.562</td><td rowspan="6">0.576</td><td rowspan="2">case 3.1</td><td rowspan="2">0.5724</td><td rowspan="2">case 4.1</td><td rowspan="2">0.576</td><td>case 5.1</td><td>0.584</td></tr>
<tr><td>case 5.2</td><td>0.576</td></tr>
<tr><td rowspan="2">case 3.2</td><td rowspan="2">0.5721</td><td rowspan="2">case 4.2</td><td rowspan="2">0.577</td><td>case 5.3</td><td>0.577</td></tr>
<tr><td>case 5.4</td><td>0.574</td></tr>
<tr><td rowspan="2">case 3.3</td><td rowspan="2">0.5717</td><td rowspan="2">case 4.3</td><td rowspan="2">0.578</td><td>case 5.5</td><td>0.585</td></tr>
<tr><td>case 5.6</td><td>0.578</td></tr>
</table>

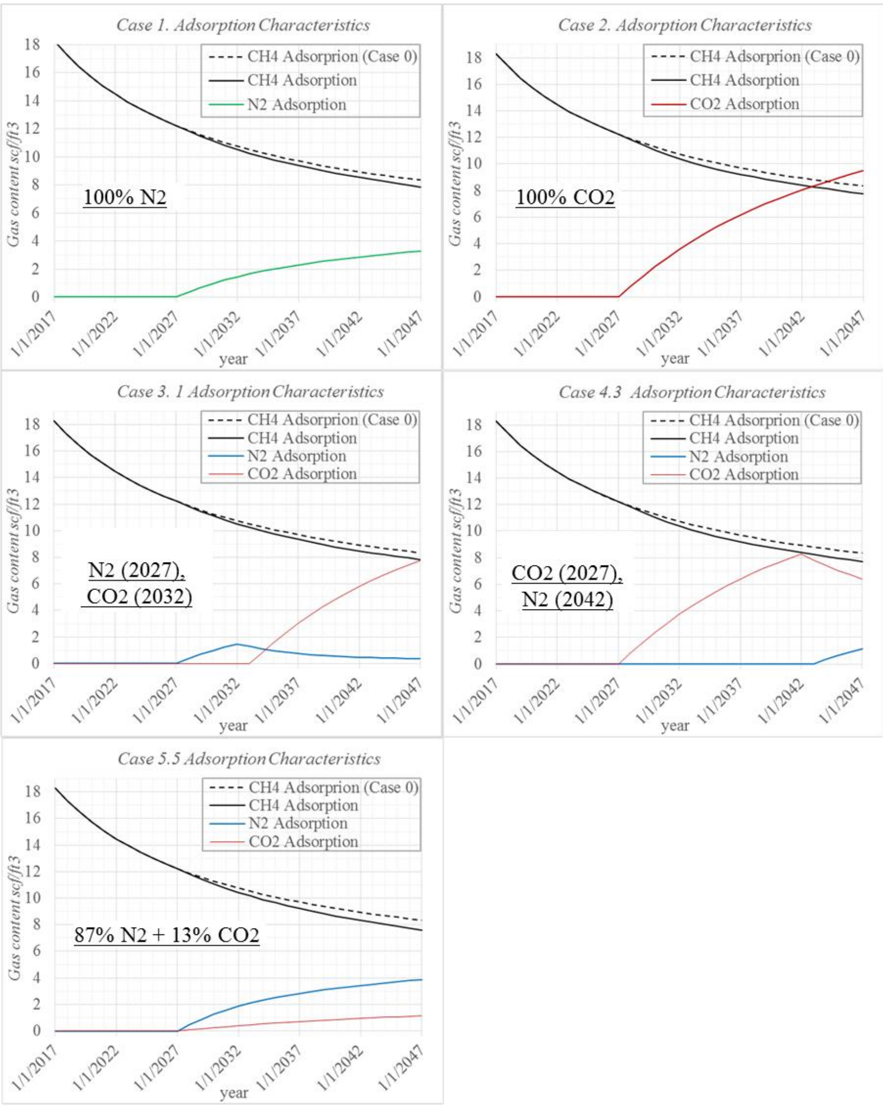

Figure 48 – Adsorption characteristics for cases 1, 2, 3.1, 4.3, 5.5

Adsorption curves for CH_4, CO_2 and N_2 are represented in Figure 48 It describes cases with 100% N_2, 100% CO_2 injection and best scenarios from N_2 – CO_2, CO_2 - N_2 alternating and mixture injection cases. CH_4 adsorbed in the seam in represented closely in Figure 49.

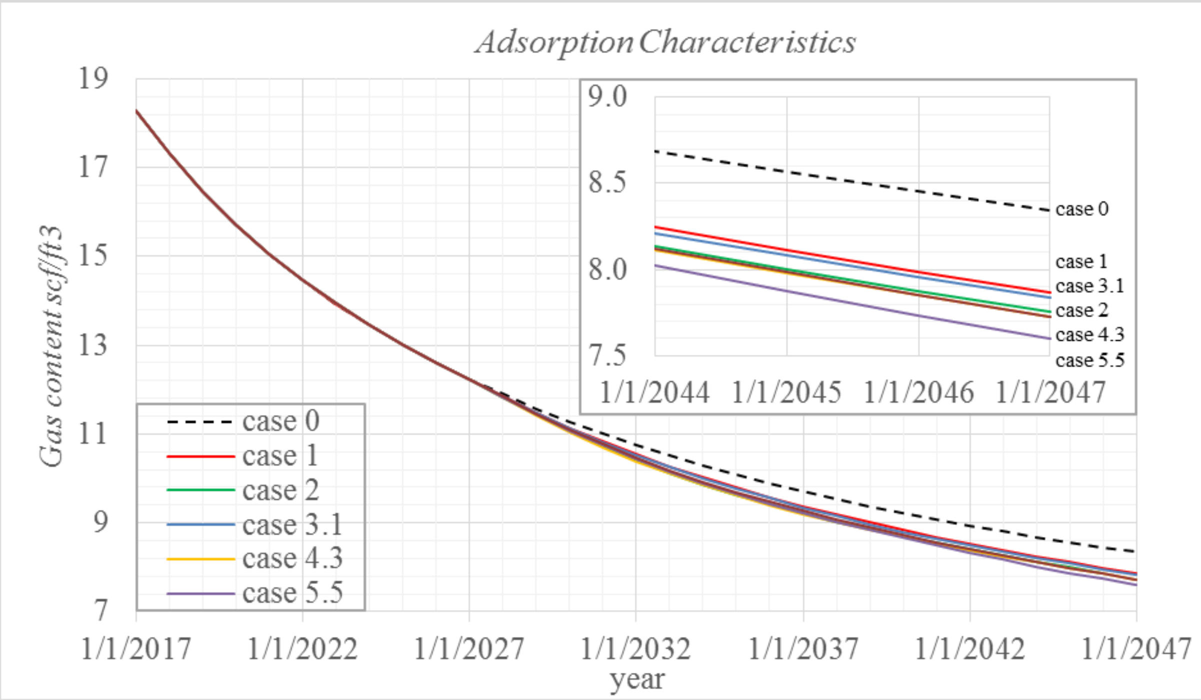

Figure 49 – CH_4 adsorption. Summary

The amount of methane adsorbed in the seam gradually decrease with the production period. The amount of the CH¤ left in 2047 is almost similar for all investigated cases. For the case 5.5 (87% of N_2 and 13% of CO_2 mixture injection) in 2047 it is equal to the 7.66 scf/ft3.

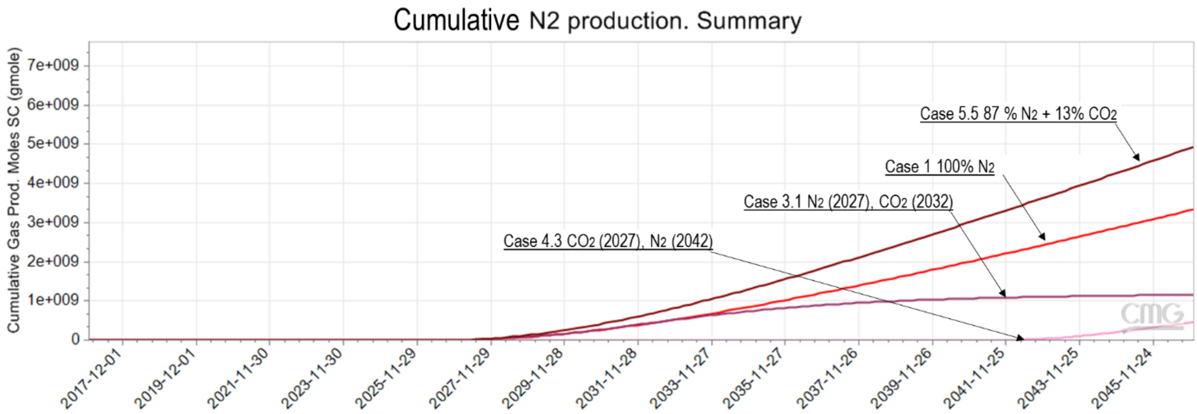

Figure 50 – N_2 production. Summary

Figure 50 represents N_2 production for mentioned before cases. It could be observed here that N_2 production is higher for the case with 87% of N_2 and 13% of CO_2 mixture injection than for the case of 100% N_2 injection. That does not correspond the tendency that with the increase of N_2 in the injection mixture, the production of N_2 also increases. That means that hypothetically the curve for 100% N_2 injection should go lower than mixture injection curve. To explain this situation, the following plot was made (Figure 51). Is shows that the curve of

N_2 production goes lower than for the mixture because less Pore Volume (PV) amount was injected to the seam in that case. N_2 injection in the 100% N_2 case is equal to 5589 MM moles vs. 7601 MM moles in the case of mixture injection. The suggested hypothetical curve for 100%N_2 injection curve is also represented in the figure.

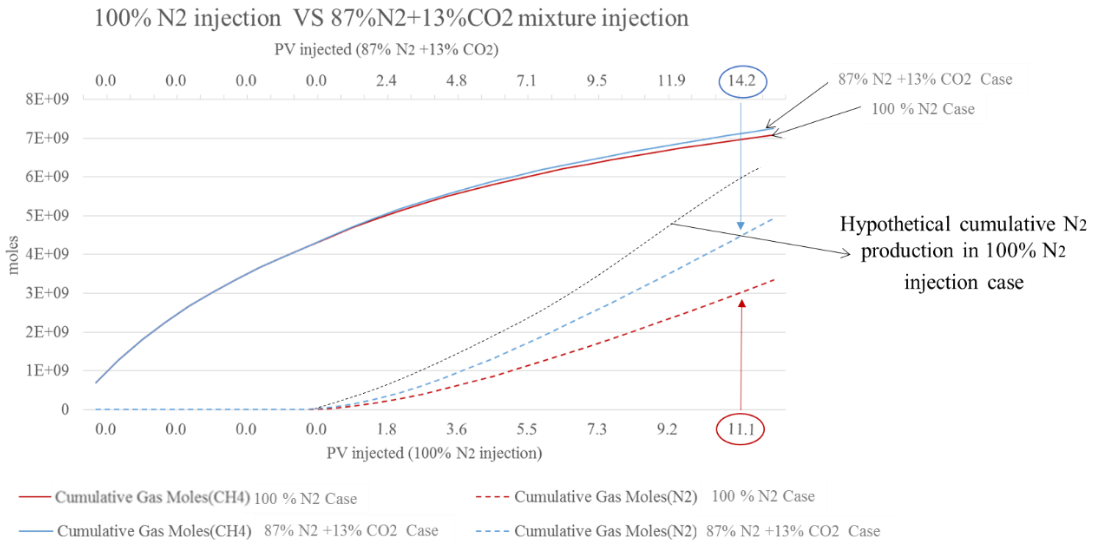

Figure 51 – 100% N_2 and 87%N_2 + 13%CO_2 mixture injection cases comparison

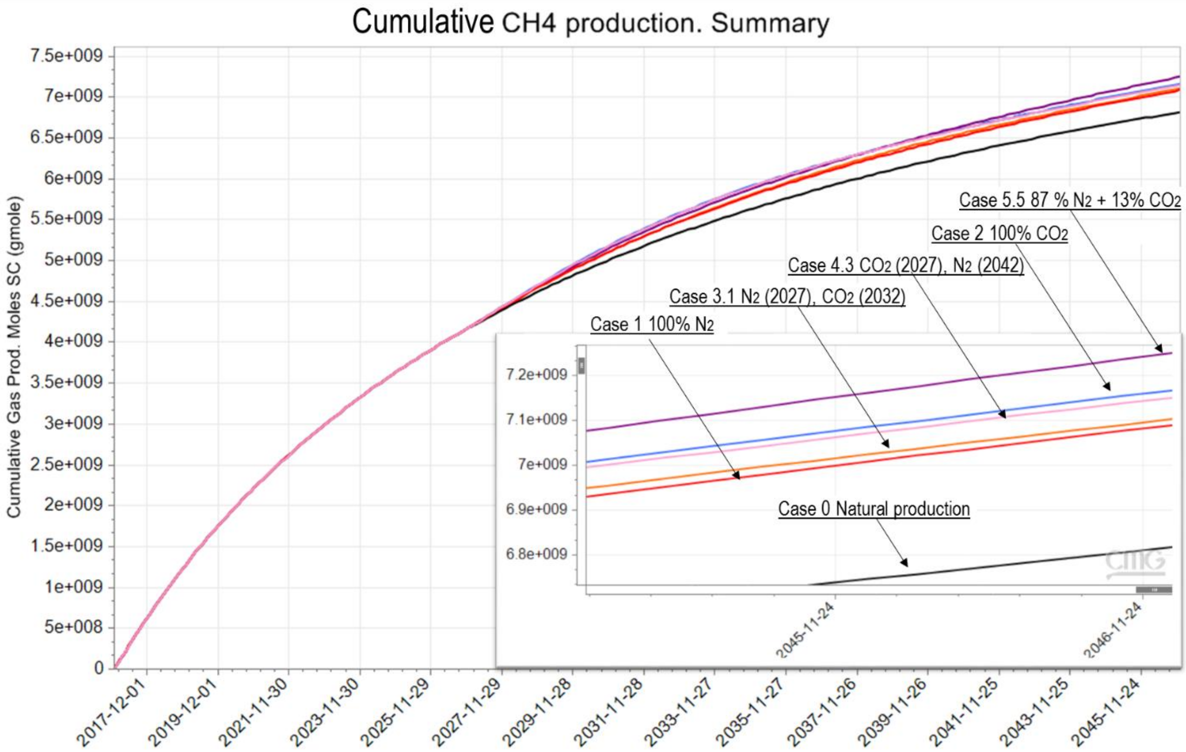

Figure 52 – Cumulative CH_4 production, summary

Cumulative CH_4 production for the best scenario in each case is shown in Figure 52. The difference between the cumulative productions in 2047 is very small. However, case 5.5 has shown the best cumulative methane value which is equal to 6059.944 MMscf.

4.3.8 Additional case. Case 6

The behaviour of the production parameters in CMG model, especially recovery is very similar to the composition of the injected gas. However, enhance recovery was different in 2 models cases. In IPM model average increase of recovery is around 20% and in the most efficient case, it is equal to 27.8%. In CMG these values are calculated to be around 2 – 3%.

This difference could be induced by the assumption that IPM model uses more theoretically based methods to build the appropriate CBM reservoir model and CMG uses more practical and field – based data.

It is possible that that IPM model does not take into account interaction of injected gases with methane and the coal matrix. With the high amount of adsorbed CO_2 gas Methane is still easily releasing from the coal matrix. While in CMG it could be possibly concluded that the matrix swelling and CH_4 trapping in the seam reduced CH_4 desorption.

The other thing which could explain such a great difference is the fact that in IPM reservoir was considered as a homogeneous tank, and when pressure decreases, gas adsorbs on the whole volume of the reservoir. Hoverer in CMG reservoir was divided into blocks. Production and injection well pattern also influence the cumulative production value. In CMG it became nearly impossible to cover the whole reservoir area with two production wells and reach this "homogeneity" which was observed in IPM. The case 6 was made to investigate this issue. It is changed case with the best injection efficiency– case 5.5. It has two additional production wells with the same characteristics as in the previous cases.

From the early months of the case 6 production (Figure 53) it could be noticed that methane desorption is going equally in each part of the reservoir. Four wells pattern helps to cover all area, so there is a minimum risk of the CH_4 trapping on the early stages.

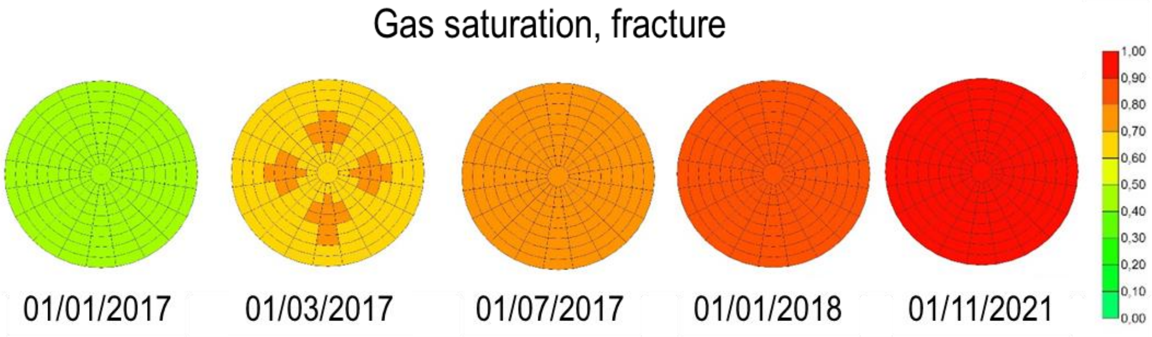

Figure 53 – Gas saturation change during the first years of production. Case 6

Following Figure 54 shows the difference between cases 5.5 and case 6. Case 5 is represented on the first row of the image, case 6 – on the second. Chosen here period is 1/1/2017 – 1/1/2027. It is a period of natural recovery without any injection. Gas desorption in the case 6 goes more substantially and homogeneously.

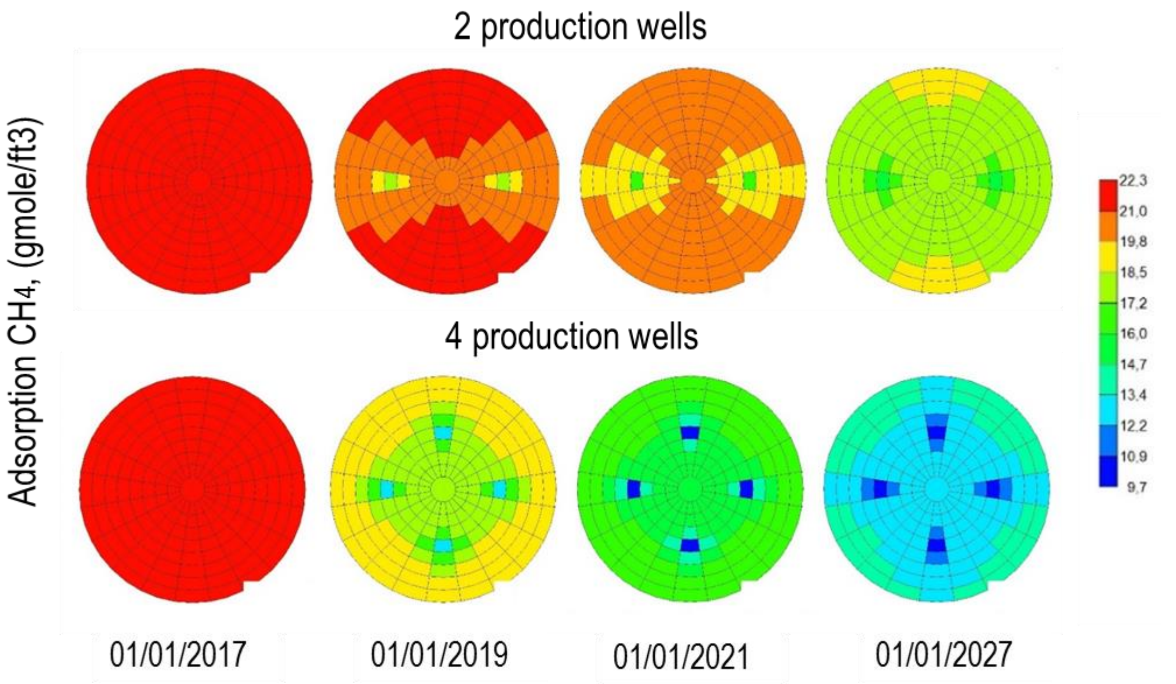

Figure 54 – CH_4 adsorption. Row 1 – Case 5.5, Row 2 – Case 6

Figure 54 shows adsorption pattern for the cases 5.5 and 6. Despite the fact that in case 6 CH_4 desorption goes more homogeneous and less CH_4 remains in the seam, CO_2 and N_2 adsorption patterns look similar. Four production wells provide coal seam with the stable pressure decline and uniform desorption volume, probably that caused an increase in recovery factor up to 0.70. That is several times higher than the recovery factor calculated in the Case 5.5 by CMG. This case could be matched with the IPM case 5.5 results. That proves that high values of recovery in IMP part are mostly caused by the theoretical base of the software, instead of more based on field experience GEM.

4.3.9 Additional cases 3a, 3b, 3c

The issue of alternating injection is not fully studied. In this work, the potential cases of N_2 alternating CO_2 and CO_2 alternating N_2 injection were investigated. 3 concepts of alternating injection of 100% N_2 and 100% CO_2 are done to perform sensitivity study:

- Case 3a – 5 – year injection cycle. Total injection period is 20 years from 1/1/2027 to 1/1/2047. One cycle, in this case, is equal to 5 years. Therefore, four equal injection cycles were done. Scheduling of the scenarios was made by starting the simulation with the shorter period of injection, increasing it with the next case. Duration of N_2 and CO_2 injections for each scenario in case 3a are represented in Table 31.

Table 31 – N_2 and CO_2 injection periods. Case 3a.

Case	*N_2 injection (years)*	*CO_2 injection (years)*
Case 3a – 1	1	4
Case 3a – 2	2	3
Case 3a – 3	3	2
Case 3a – 4	4	1

- Case 3b – Injection with ratio 1:1. Five scenarios are described in Table 32. In these simulation cases ratio of the injection period of N_2 and CO_2 is kept the same, while injection period increases with the case.

Table 32 – Scenarios for case 3b

Case	*N_2 injection (years)*	*CO_2 injection (years)*	*Cycle (years)*
Case 3b – 1	0.5	0.5	1
Case 3b – 2	1	1	2
Case 3b – 3	2	2	4
Case 3b – 4	5	5	10
Case 3b – 5	10	10	20

- Case 3c – Injection with different ratios. Ratios and cycles of injection are different from scenario to scenario. Cycles and rates for case 3c are described in Table 33. Case 3c – 3 is the same as the case 3a – 1, however here it is considered regarding ratio influence on the production recovery and reservoir behaviour.

Table 33 – Scenarios for case 3c.

Case	*N_2 injection (years)*	*CO_2 injection (years)*	*Cycle (years)*	*Ratio (years)*
Case 3c – 1	2	4	6	1/2
Case 3c – 2	1	3	4	1/3
Case 3c – 3 (3a – 1)	1	4	5	1/4

Described above cases were simulated, and all needed data was processed and represented in a graphical form.

CH_4, CO_2 and N_2 produced amounts are demonstrated Appendix. CO_2 adsorption (Figure 56) and production curves go upper with the later CO_2 injection. Both characteristics increases during the CO_2 injection period and respectively decrease during the N_2 injection period. It could be observed that for the case with four years of N_2 injection, while the N_2 injection was performed, the amount of CO_2 already adsorbed in the seam decreases slightly. After the whole injection period CO_2 adsorbed has increased noticeably.

With the case of 4 years of CO_2 injection, the situation is opposite. During the CO_2 injection N_2 adsorption curve (Figure 55) is varying slowly. Adsorbed in the seam N_2 with the CH_4 is replaced by CO_2 as it has a greater affinity to adsorb to the coal. By the end, the amount of N_2 adsorbed in the reservoir is almost equal to the value that was adsorbed by during the 1st injection period.

First injection period and its duration are very important since it defines the height of the CO_2 curve peaks. The higher is this peak the more amount of CO_2 was adsorbed in the coal matrix at once. N_2 stays more in the form of free or dissolved in the water gas than CO_2.

Simulated results show that case with 1 year of N_2 and 4 years of CO_2 cycle gives the best results.

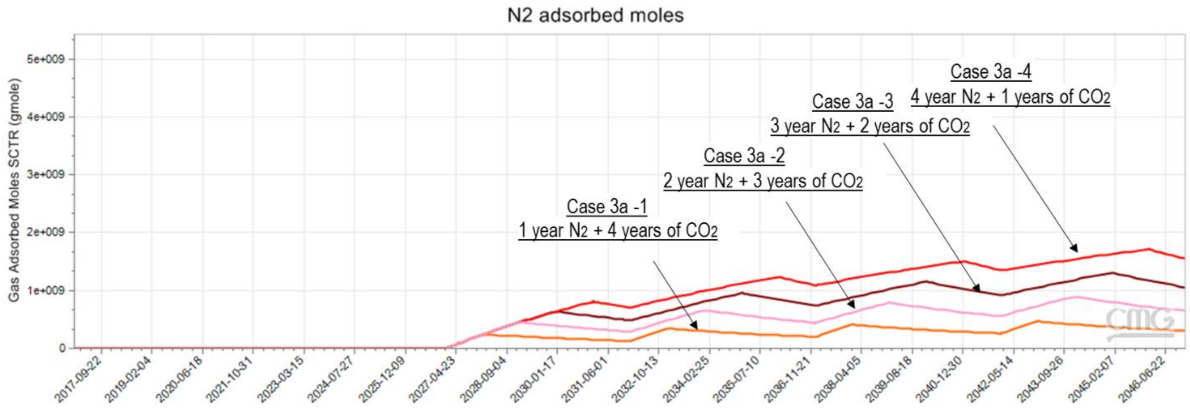

Figure 55 – N_2 adsorption characteristics, case 3a

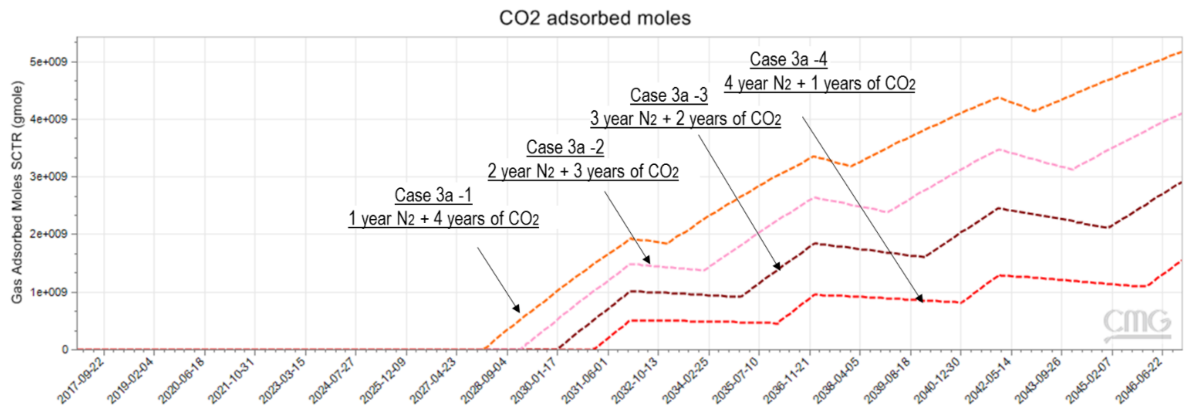

Figure 56 – CO_2 adsorption characteristics. case 3a

Adsorption curves for the sensitivity case 3b are represented in Figure 57 and Figure 58. The frequency of the injection cycles plays an important role in the CH_4 production. The end points of the N_2 and CO_2 curves for all cases here are positioned in almost the same range of values. Whereas the curves pattern is changing more drastically from the case 3b – 1 to the case 3b – 5.

When N_2 and CO_2 injections are performed during the short period that allows equalizing the effect from both injected gases to the methane production. More often injections change one another the higher is the result of the CH_4 recovery.

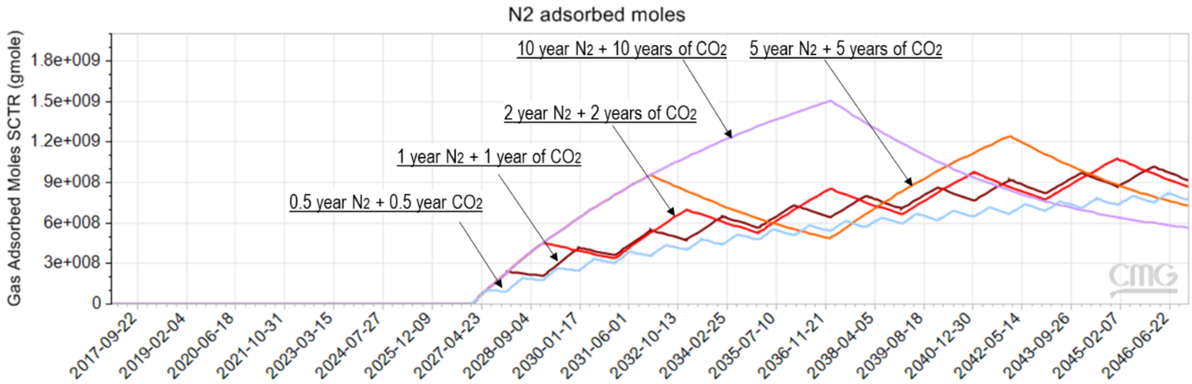

Figure 57 – N_2 adsorbed moles. Case 3b

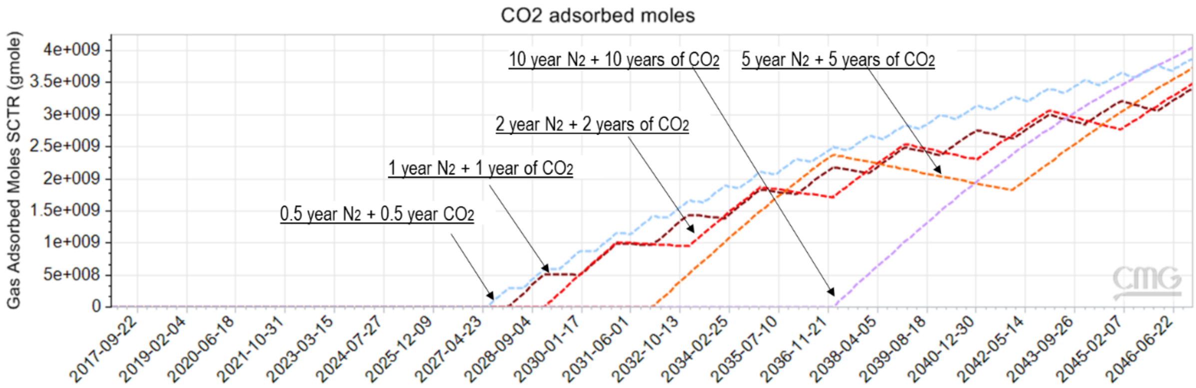

Figure 58 – CO_2 adsorbed moles. Case 3b

When it comes to the different ratios, the tendency is that the shorter is the period of the first N_2 injection – the better is CH_4 production result. By increasing the ratio of N_2 and CO_2 injection and thus decreasing the number of total injection cycles, it is possible to reach good CH_4 recovery. CO_2 injection period of 4 years (case 3c – 3) equalised by one year of N_2 injection allows avoiding massive matrix swelling and gas trapping.

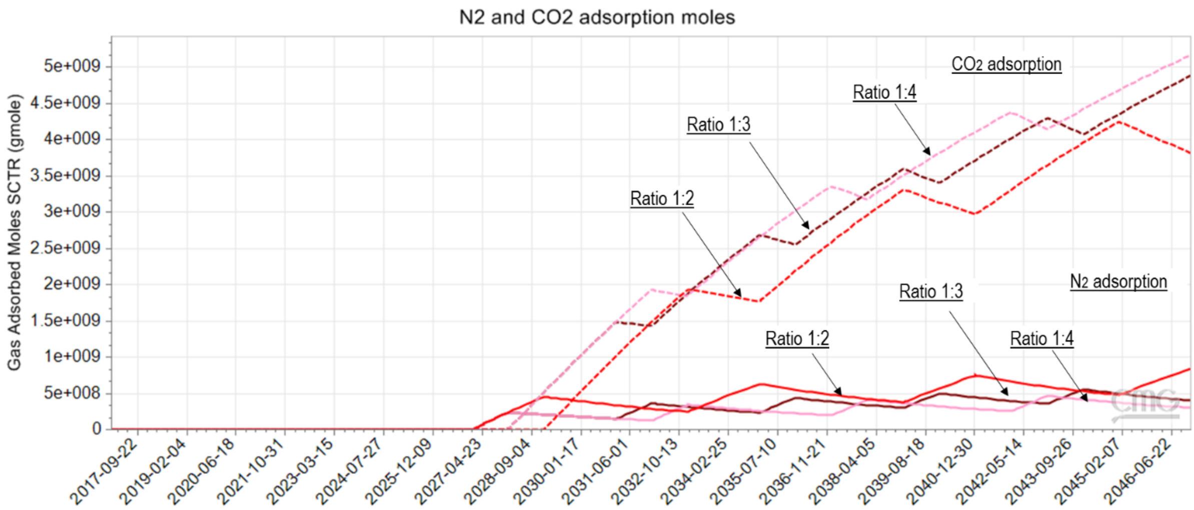

Figure 59 – CO_2 and N_2 adsorption. case 3c

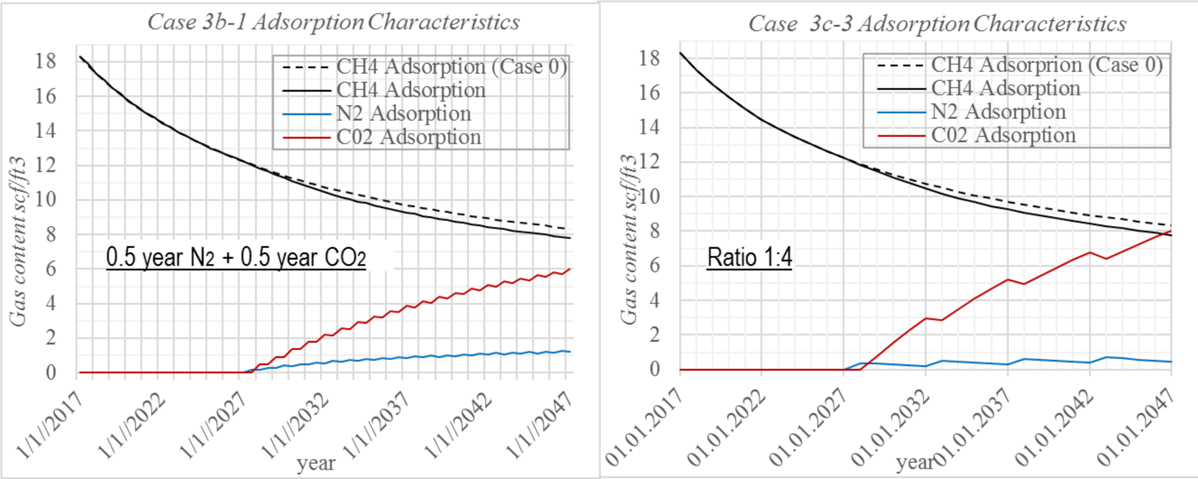

Figure 60 – Adsorption characteristics of cases 3b – 1 and 3c – 1

Figure 60 shows the adsorption characteristics of the case 3b – 1 and 3c – 3 – cases with the highest efficiency of CH_4 recovery. In both cases CO_2 adsorbed in the seam by the end of the production period is high and is equal to 6 and 8 scf/ft3 for cases 3b – 1 and 3c – 3 respectively.

Table 34 – RF. Additional Case 3

Case 3a	*Recovery factor, fraction*	*Case 3b*	*Recovery factor, fraction*	*Case 3c*	*Recovery factor, fraction*
Case 3a – 1	0.5717	Case 3b – 1	0.5711	Case 3c – 1	0.5707
Case 3a – 2	0.5706	Case 3b – 2	0.5705	Case 3c – 2	0.5715
Case 3a – 3	0.5695	Case 3b – 3	0.5702	Case 3c – 3 (3a – 1)	0.5717
Case 3a – 4	0.5686	Case 3b – 4	0.5696	–	–
–	–	Case 3b – 5	0.5682	–	–

Variation of the recovery factor in additional cases 3a, 3b and 3c is very small. Case 3a – 1 showed recovery which is equal to 57.17%. This value is not higher than the result from case of investigated previouslyN_2 - CO_2 alternating injections.

4.3.10 Additional cases 4a, 4b, 4c

The CO_2 alternating N_2 strategy could be effective. Sensitivity study similar to the additional cases 3a, 3b and 3c was performed. All cases and scenarios are the same, while the first injected in the injection cycle gas is 100% CO_2.

Table 35, Table 36 and Table 37 represent the duration of injections and cycles for the further investigation.

- Case 4a – 5 – year injection.

Table 35 – N_2 and CO_2 injection periods. Case 4a.

Case	*CO_2 injection (years)*	*N_2 injection (years)*
Case 4a – 1	4	1
Case 4a – 2	3	2
Case 4a – 3	2	3
Case 4a – 4	1	4

- Case 3b – Injection with ratio 1:1.

Table 36– Scenarios for case 4b.

Case	*CO_2 injection (years)*	*N_2 injection (years)*	*Cycle (years)*
Case 4b – 1	0.5	0.5	1
Case 4b – 2	1	1	2
Case 4b – 3	2	2	4
Case 4b – 4	5	5	10
Case 4b – 5	10	10	20

- Case 4c – Injection with different ratios.

Table 37 – Scenarios for case 4c.

Case	*CO_2 injection (years)*	*N_2 injection (years)*	*Cycle (years)*	*Ratio (years)*
Case 4c – 1	4	2	6	1/2
Case 4c – 2	3	1	4	1/3
Case 4c – 3 (3a – 1)	4	1	5	1/4

CH_4, CO_2 and N_2 gas mole fraction curves are demonstrated in Appendix. Since the injection period starts in 1/1/2027 CH_4 gas mole fracture decreases from 1 to approximately 0.6 (fraction). CO_2 adsorption curve goes upper with the smaller N_2 injection period. It increases during the CO_2 injection period and decreases during the N_2 injection period. CO_2 injection period and its duration distinguish the behaviour of first CO_2 curve peaks. Latter defines how fast the amount of CO_2 in the seam will increase during the injection period.

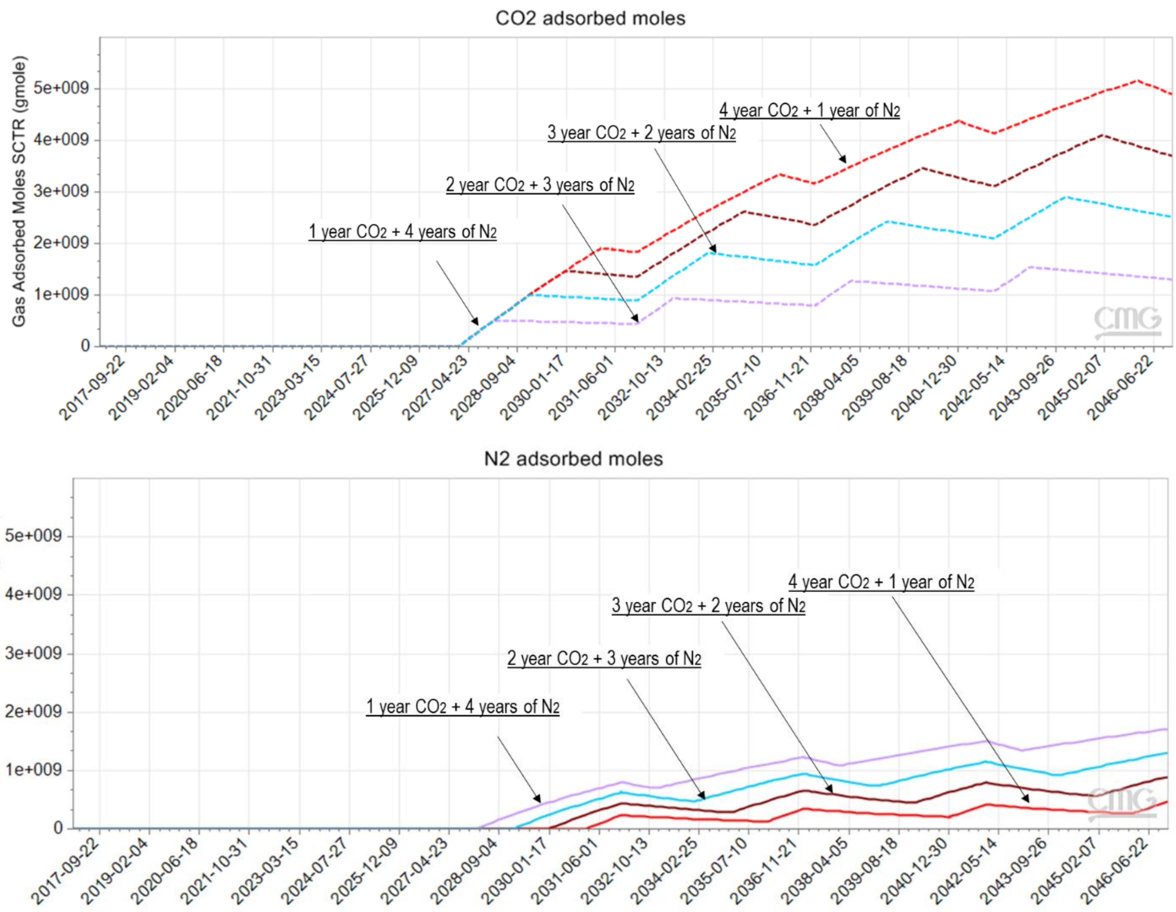

Figure 61 – N_2 and CO_2 adsorption characteristics

The difference for adsorbed and free gas is around 0.02 – 0.05 in the case of N_2 and for a CO_2 curve – it is becoming higher with the longer CO_2 injection period. It could be observed from the graphs that highest curve of CO_2 adsorption corresponds to the lowest curve of N_2 adsorption. N_2 and CO_2 concentrations gradually increase and CH_4 concentration decrease in both matrix and fracture.

Gas adsorption curves for the sensitivity case 4b are represented on the on the Figure 62. The frequency of the injection cycles plays an important role in the CH_4 production. The end points of the N_2 and CO_2 curves for all cases doesn't differ drastically. The range of the values is equal to approximately 1 – 1.4 MM moles and 2.5 – 3.3 MM moles for N_2 and CO_2 respectively. Changing curves patterns are also represented in the figures.

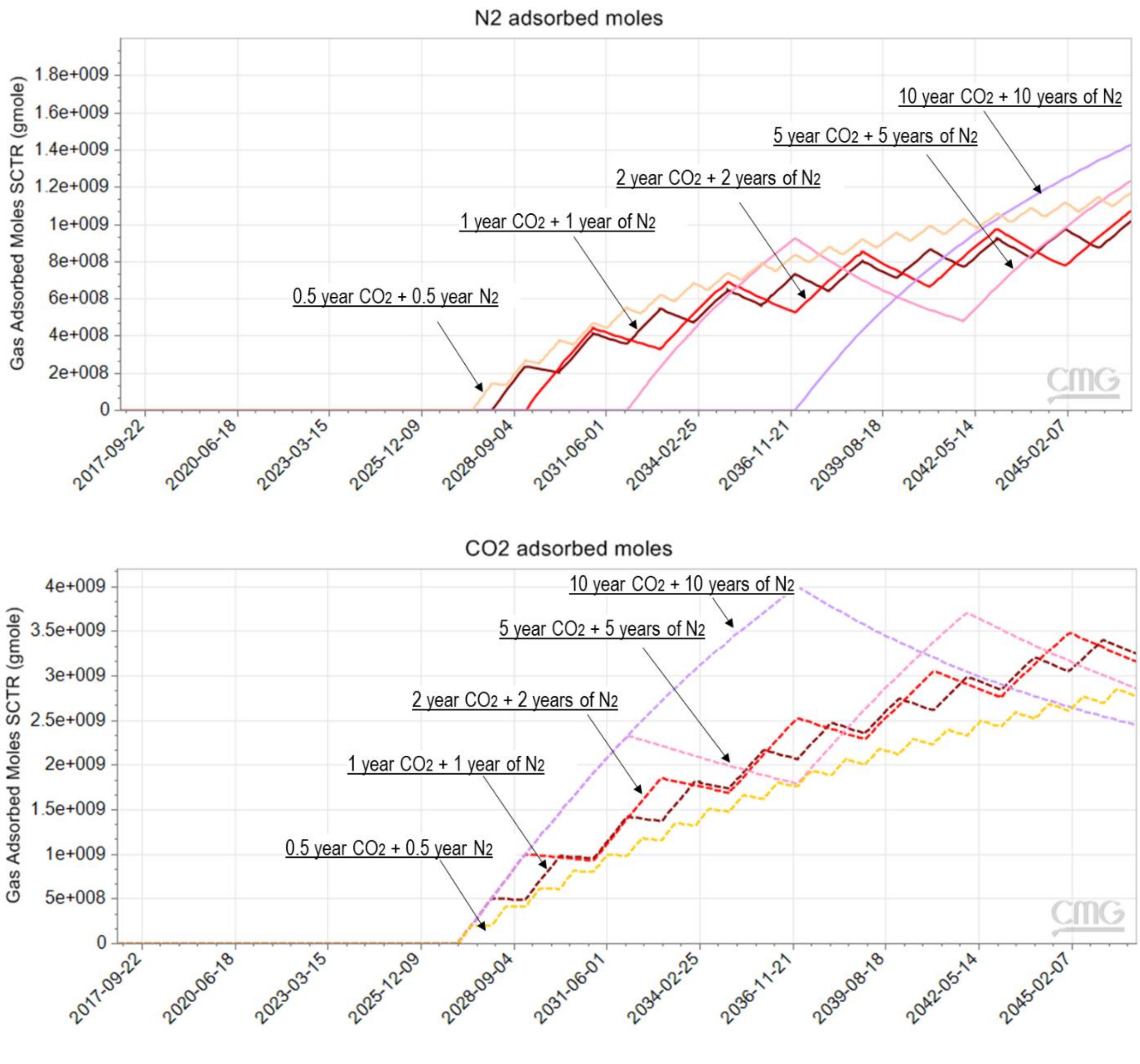

Figure 62 – Case 4b. N_2 and CO_2 adsorption characteristics.

The longer is the injection period of one gas – the higher are the peaks on the curves. The period of CO_2 injection of 10 years is enough to prevent coal swelling effect as it was described in the case of 100% CO_2 where injection period of CO_2 was 20 years.

More rarely injections change one another, more stable is CH_4 decline curve. In case 4b – 5 (10 years of CO_2 injection + 10 years of N_2 injection) during the N_2 injection period, more CO_2 occurs in the fractures similarly to the case 4.3 described before.

In the different ratios case – the tendency is that the larger is the ratio between CO_2 and N_2 injection is the period – the better is CH_4 production result. Increasing the number of total injection cycles and making the smaller periods between the CO_2 injections allows achieving good CH_4 recovery. CO_2 injection period of 1 year (case 4c – 1) equalised by two years of N_2 injection is optimal for the enhanced recovery.

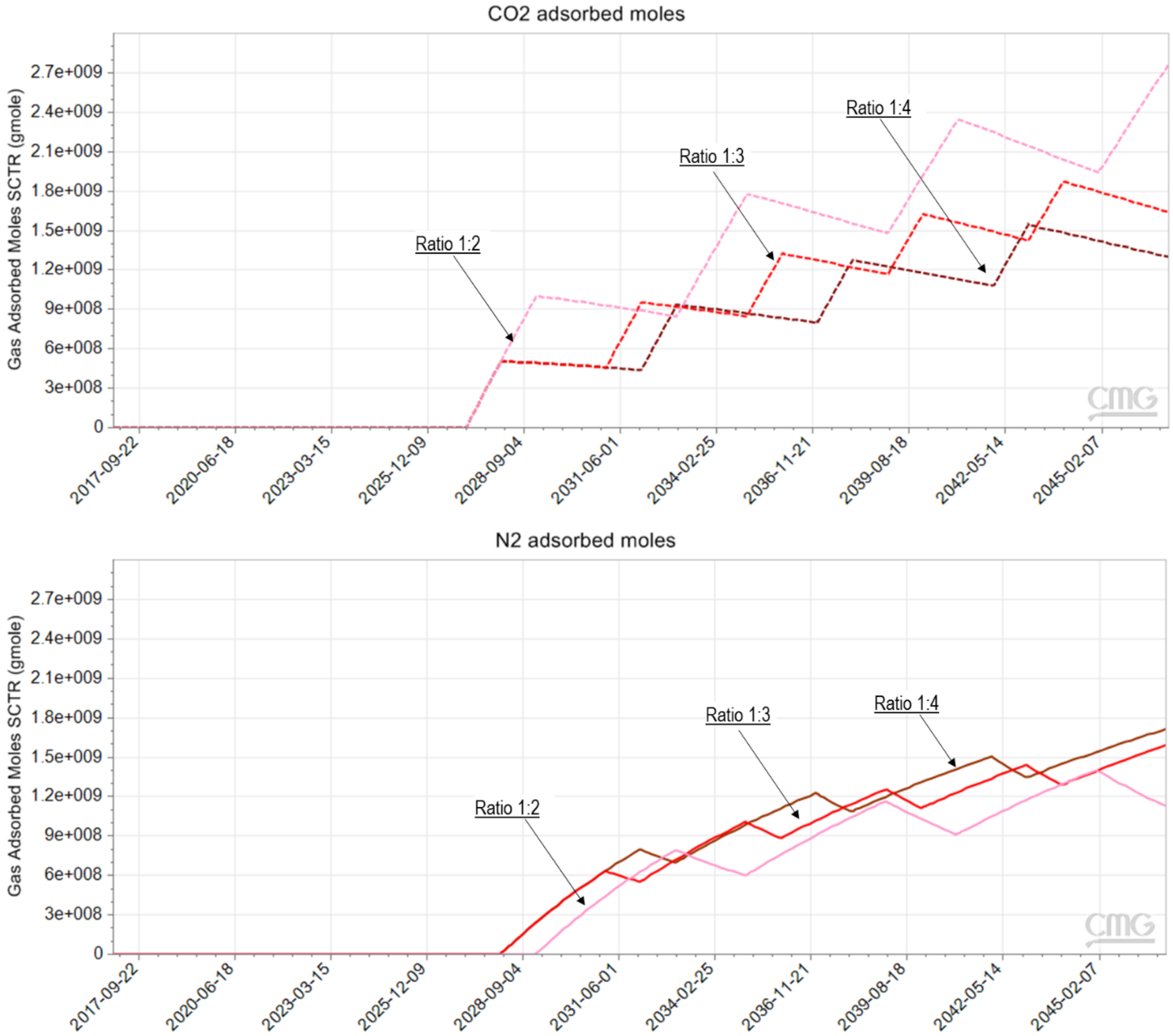

Figure 63 – CO_2 and N_2 adsorption. Additional case 4

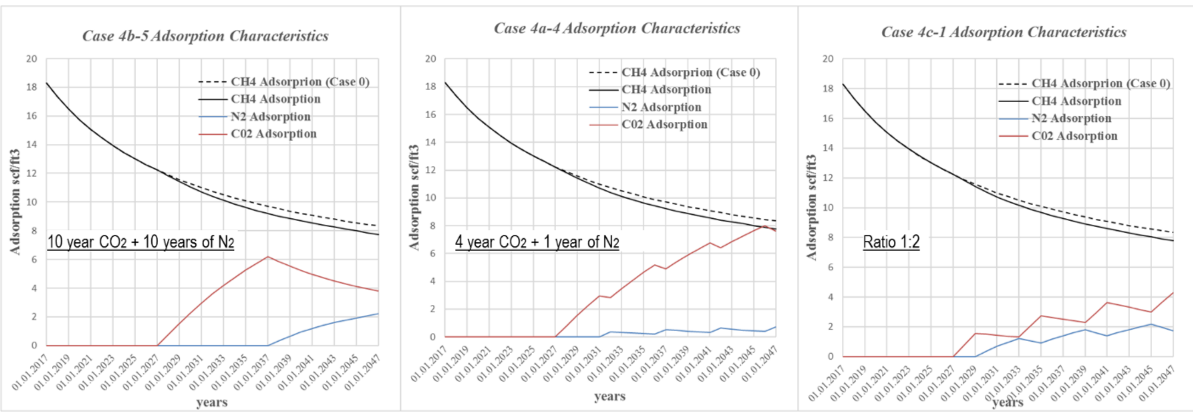

Figure 64 – Adsorption characteristics – additional case 4

The figure above shows gases adsorbed in the seam. These 3 cases are the most efficient among cases 4a, 4b and 4c. It could be noticed that the amount of adsorbed in the seam CO_2 is very different. In case 4a – 4 with injection cycle of 4 years of CO_2 + 1 year of N_2, CO_2 adsorbed by the end of simulation period is the highest.

Table 38 – Recovery factor for cases 4a, 4b and 4c

Case 4a	*Recovery factor, fraction*	*Case 4b*	*Recovery factor, fraction*	*Case 4c*	*Recovery factor, fraction*
Case 4a – 1	0.5700	Case 4b – 1	0.5706	Case 4c – 1	0.5712
Case 4a – 2	0.5714	Case 4b – 2	0.5712	Case 4c – 2	0.5701
Case 4a – 3	0.5723	Case 4b – 3	0.5718	Case 4c – 3 (4a – 1)	0.5700
Case 4a – 4	0.5729	Case 4b – 4	0.5725	–	–
–	–	Case 4b – 5	0.5739	–	–

The most efficient scenario, in that case, is case 4b – 5 with the CH_4 recovery of 57.29 %. Taking in consideration that injection and production pattern characteristics, described above don't allow to reach large recovery value of coalbed methane production, these results could possibly be increased by the use of other well patterns. It also could be suggested that after the implementation of different well distribution, variation between the sensitivity cases results could possibly become larger but following that same tendency.

To prove that additional simulation has been run. Injection and production pattern was shown in the figure below. Four production and three injection wells have been distributed into the reservoir and cases 3.1, 4.3 and 4b – 5 (scenario with the best recovery among the additional sensitivity cases) has been scheduled and simulated.
New characteristics of the case 4b – 5 are represented in the figure below

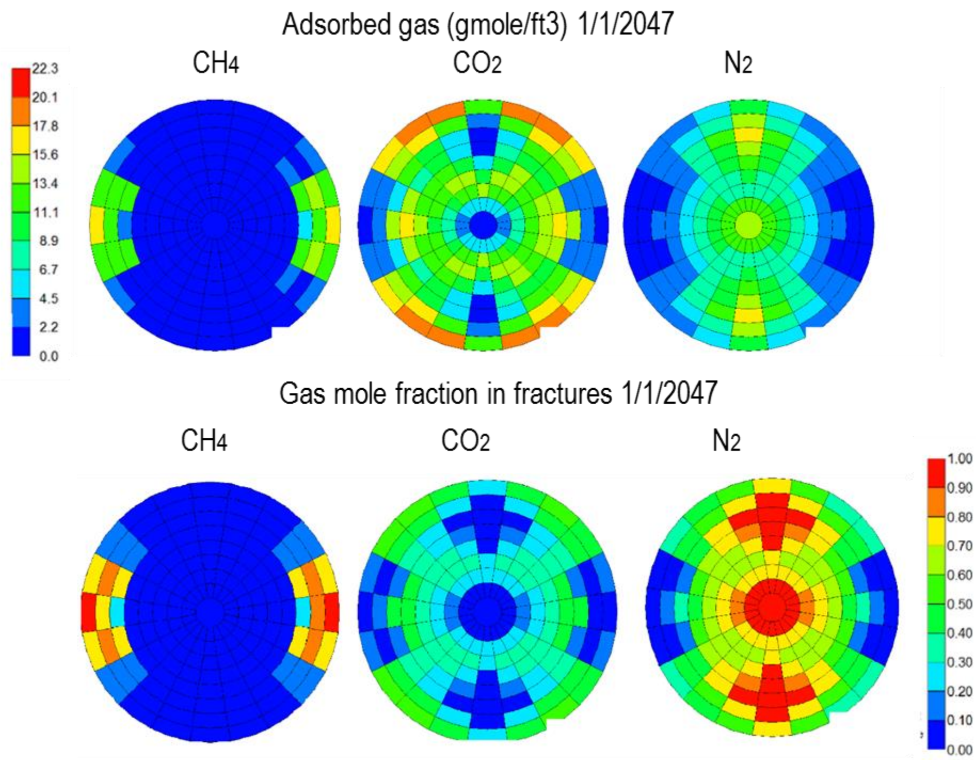

Figure 65 – Adsorption and gas mole fracture characteristics of the case with new well pattern.

The figure shows that CH_4 desorption process was more efficient in case 6, but also a large amount of CO_2 and N_2 remained in the seam in 2047. Amount of N_2 injected is higher in the macropores then in the coal micropores. The Recovery, in that case, were equal to 85.9, 87.7 and 86.4 respectively. The difference between cases contained 1 – 2% instead of initially calculated 0.1 – 0.2 %. These results show that well pattern in CMG seriously affects the production recovery values and that factors could be investigated in the further studies.

4.4 *Results Summary*

Simulation results showed that different software environments estimate coalbed methane reservoir production from the different aspects of the problem. In IPM it is necessary to consider characteristics that describe the interaction of different gases with the coal seam and each other. It is important to understand that reservoir was simulated as a homogeneous tank with equally distributed adsorption characteristics. This software possibly overestimates the production and recovery factor.

Several cases of ECBMR were considered in this project. An overall conclusion for both simulation software is the following:

100% N_2 or 100% CO_2 injection improves CH_4 recovery, but not significantly, because of early breakthrough and fast gas production to the production wells. The mechanism of N_2 injection is that it reduces a partial pressure of CH_4 and remains free, because of less adsorption affinity. CO_2 interaction mechanism with the coalbed methane consists of 2 steps. Firstly, it reduced the partial pressure of methane in the gas mixture, allowing it to release from the coal matrix and then methane is replaced with preferential adsorption of CO_2. During the 100%, CO_2 injection CO_2 massively adsorbs to the coal surface, and thus blocks micropores and causes swelling.

Nevertheless, 100% CO_2 injection is more efficient than 100% N_2 injection.

It is interesting to observe that the CH_4 recovery is dependent not only on the injected gas but also on the sequence of injection.

It is efficient to use a combination of both gases to prevent an early breakthrough and swelling effect.
One of the promising techniques is an N_2 – alternating – CO_2 or CO_2 – alternating – N_2 injection. Simulation showed that a duration of injection periods affects the production. It is also important which gas is the first in the alternating injection. The sensitivity was performed to investigate this issue. The results of alternating injection depend on the ratio and alternating frequency. In the case of N_2 – alternating – CO_2 the production increases if CO_2 is injected shortly after N_2 injection. The 1 – to – 4 ratio and 5 – years injection cycle were found to be optimal. In the case of CO_2 – alternating – N_2 injection, it was observed that long CO_2 injection period before short N_2 injection period shows better efficiency in 5 – years cycle. Ratio 4:1 shows the best results. Longer periods demonstrate better recovery.

Considering the constant ratio 1:1 and varying frequencies, it was shown that ten years injection period was optimal. That is maybe because ten years CO_2 injection period is enough to prevent the effect of coal swelling and to produce a large amount of CH_4. Then ten years of N_2 injection help to extract the remaining after CO_2 injection CH_4, moreover N_2 has less affinity to adsorb, and thus less impact to the CO_2 remained in the seam. So CO_2 will not breakthrough to the production massively. The combination of these factors gives efficient methane production results.

Another approach was by injection of a mixture of N_2 and CO_2. It was found that mixture with 87% N_2 and 13% CO_2 gave the best recovery. ECBMR depends strongly on the composition of the injection gas. Prediction showed that 100% N_2 or 100% CO_2 injections are less effective than a mixture of these gasses in the proportion of 87% and 13% respectively. Composition close to the flue gas allows to reach better contact with the seam and also with the coalbed methane. Two different mechanisms of interaction with the seam in their combination could give one better mechanism, where each gas is doing its part. N_2 is reducing CH_4 partial pressure and, thus releasing it from the seam, and CO_2 adsorbs to the seam releasing the rest of it. It is beneficial that the content of CO_2 is only 13%. That reduces possible risks of matrix swelling during the CO_2 injection. For this reason, compositions with a higher amount of CO_2 showed less effective results. Also, the amount of injected gas (N_2) that was produced decreases with the less % of N_2 in the mixture, thus making larger the amount of produced methane. This scenario perhaps is the optimal case where swelling, N_2 breakthrough and gas trapping is minimal.

Flue gas could be an ideal solution for the ECBMR. It is not only high effective for recovery but also available and could make this kind of projects economically profitable.

On the base of the simulations that were performed in this thesis, it could be suggested that the optimum case for the ECBMR simulation is a reservoir with production well pattern that covers all simulating area. Moreover, not only production wells should be distributed properly, like it has been done in the case 6. To reach maximum results, it is suggested to use several vertical wells, or horizontally oriented wells also for injection. It would make the model more homogeneous and would allow reaching high recovery values from both primary and secondary production.

It is necessary to continue the studies concerned CBM Reservoir exploitation. They could become a key to the future clean resources of energy all over the world.

Chapter 5
Conclusion

The project was undertaken to define main parameters that affect CH_4 production during enhanced coalbed methane recovery. The thesis contributes to the existing researches of the Enhanced CBM Recovery simulation and optimisation. These aspects are important regarding acceleration of CBM development worldwide.

Overall this study strengtheneth the idea that ECBMR simulation should be performed to predict reservoir behaviour and evaluate all difficulties related to the production from coalbed reservoirs. A complete literature review was made to create the reservoir models and also to study main production tendencies.

IPM and CMG (GEM) models were compared. Software result differs drastically. However general tendencies were observed. Taken together the results from both software environments it was suggested that IPM modelling of CBM reservoir could overestimate the production values. Developed simulation model showed that ECMBR could significantly increase the original CBM reservoir recovery. Though, recovery results for all studied cases simulated in IPM and CMG (GEM) differs slightly.

In this investigation, the aim was to ascertain the factors that affect the CBM production. There are two main ways to achieve methane production from the coalbed.

First of all, it is dewatering process that allows decreasing the reservoir pressure, and thus beginning the gas production process. After 30 years of the original production, reservoir recovery reached 53.1 % (IPM) and 54.9% (GEM).

The other way is the implementation of the enhanced recovery techniques. Simulation of five different types of ECBMR was performed in this work. The objective here was to access the optimal variant of ECBMR injection.

100% N_2 injection occurred to reach the lowest recovery values relatively to the other methods: 75.7% (IPM) and 56.2 % (GEM). Large breakthrough of N_2 to the production well was observed in this case. 100% CO_2 injection showed that injection time of CO_2 should be limited, because of the matrix swelling effect taking place in the seam. However, recovery was estimated equal to 78.2 % (IPM) and 57.6 % (GEM). Both: breakthrough and swelling effects possibly caused methane trapped in the seam.

It is important to understand that coalbed methane behaviour during the CO_2 and N_2 injection differs. N_2 injection goes through a 1 – stage process: its main mechanism is the reduction of CH_4 partial pressure. However, CO_2 injection is more complicated as it has 2 – stage process – firstly reduces the partial pressure of CH_4 and then with its preferential adsorption allows CO_2 to replace CH_4 from the seam. Simulation data analysis contributes to the understanding of that processes. Described in thesis gas rate, adsorption, gas mole fraction and cumulative production curves affirm suggested in this work statements.

The production behaviour during the combination of injected gases or their mixture corresponds to a more complex process. The results showed the relevance of injection sequence impact on the CH_4 recovery during the alternation injection. It is more efficient to perform CO_2 injection first to get high production values. Furthermore, the time interval of injection, injection ratio and frequency affects the production of gas during N_2 - CO_2 alternating and CO_2 - N_2 alternating injection.

- CO_2 injection made shortly after the N_2 injection will benefit more. Ratio 1:4 showed the noticeable increase in the N_2 - CO_2 alternation ECBMR. In that case, nitrogen breakthrough to the CH_4 production is reduced, and the amount of CO_2 is not high enough to cause coal swelling. Recovery was estimated at 57.27% (GEM).
- A constant ratio of 1:1, high frequency of injection (e.g. half – year of N_2 and a half year of CO_2) gives enhanced recovery results – 57.11% (GEM) During the short period, injection gases manage to neutralise effect from each other.
- CO_2 - N_2 alternating injection results are opposite: Long CO_2 injection and then N_2 injection give good results. During that type of injection, N_2 affects the methane desorption more directly than in N_2 - CO_2 ECBMR case and allows to reach 57.29% recovery (GEM)
- Low injection frequency (10 – to – 10 years) shows better methane production. Ten years period of CO_2 injection is sufficient to prevent matrix swelling and resulted in 57.39 % of recovery.

The research has also demonstrated that mixed gas injection mechanism can increase the recovery. It is shown in this study that there is the optimal composition of N_2 and CO_2 in the mixture which is corresponding to 87% of N_2 and 13% of CO_2. Deviation from that composition will reduce the efficiency of ECBMR process. There should be a compromise between N_2 breakthrough to the production which is caused by high % of N_2 in the injected mixture (100% N_2 injection) and CO_2 swelling effect which also occurs with the increase of CO_2 % (100% CO_2 injection). Simulations identified that composition which minimises disadvantages of the injection is 87% N_2 and 13% of CO_2. Consequently, N_2 concentration reduces from 100% to 87% and minimum concentration of CO_2 (13%) is recommended to use for the future ECBM projects. The recovery, in this case, was equal to 81.24 % (IPM) and 58.5% (GEM). That is higher that cases with 100% of N_2 or CO_2 and also their alternation injection.

Possible CO_2 Sequestration process was investigated. Suggested in this work CO_2 – ECBMR where injected gas was 100 % CO_2, showed the most efficient results regarding the CO_2 adsorption to the seam. During the 20 – year injection period, the specific volume of 12.31 scf/ft3 (IPM) and 9.42 scf/ft3 (GEM) remained in the coal. Short – time N_2 injection, performed with sequestration process, could prevent coalbed matrix from massive swelling. This option could be possible in more long – term perspective.

The contribution of this study was to confirm previously made research and simulation models results concerning the mixture CO_2 and N_2 injection scenario of ECBMR.

Moreover, the sensitivity analysis of N_2 - CO_2 and CO_2 - N_2 alternating injection undertaken here has extended our knowledge of complex interaction mechanisms that take place in the coalbed reservoirs during the enhanced recovery. This research has a potential to be a base for future studies and researches of ECBMR simulations.

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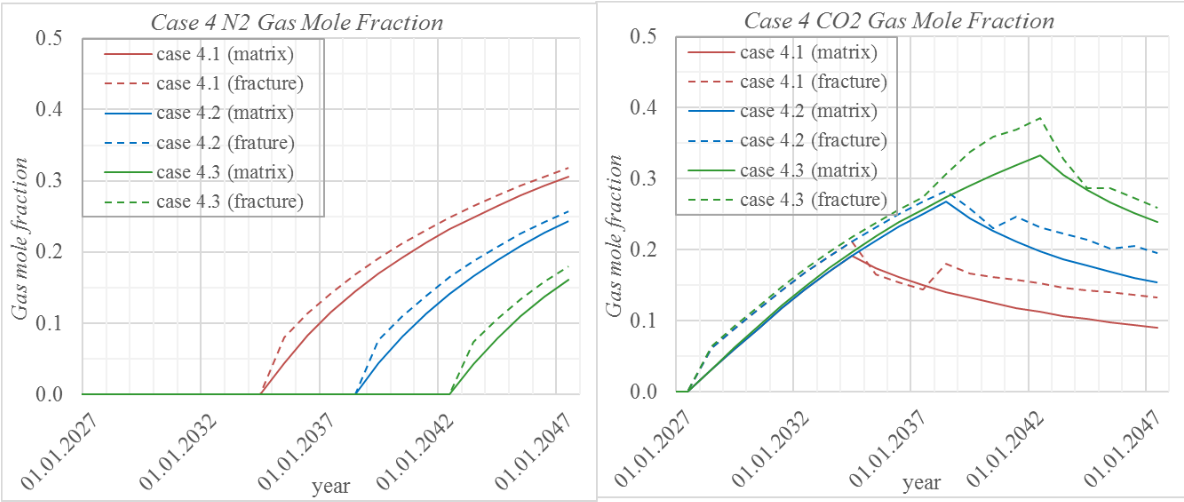
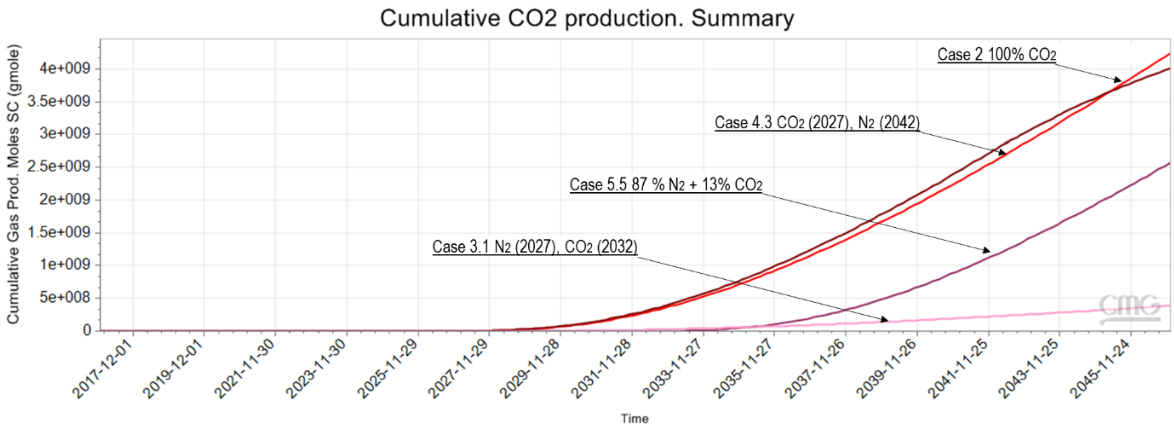
Appendix A

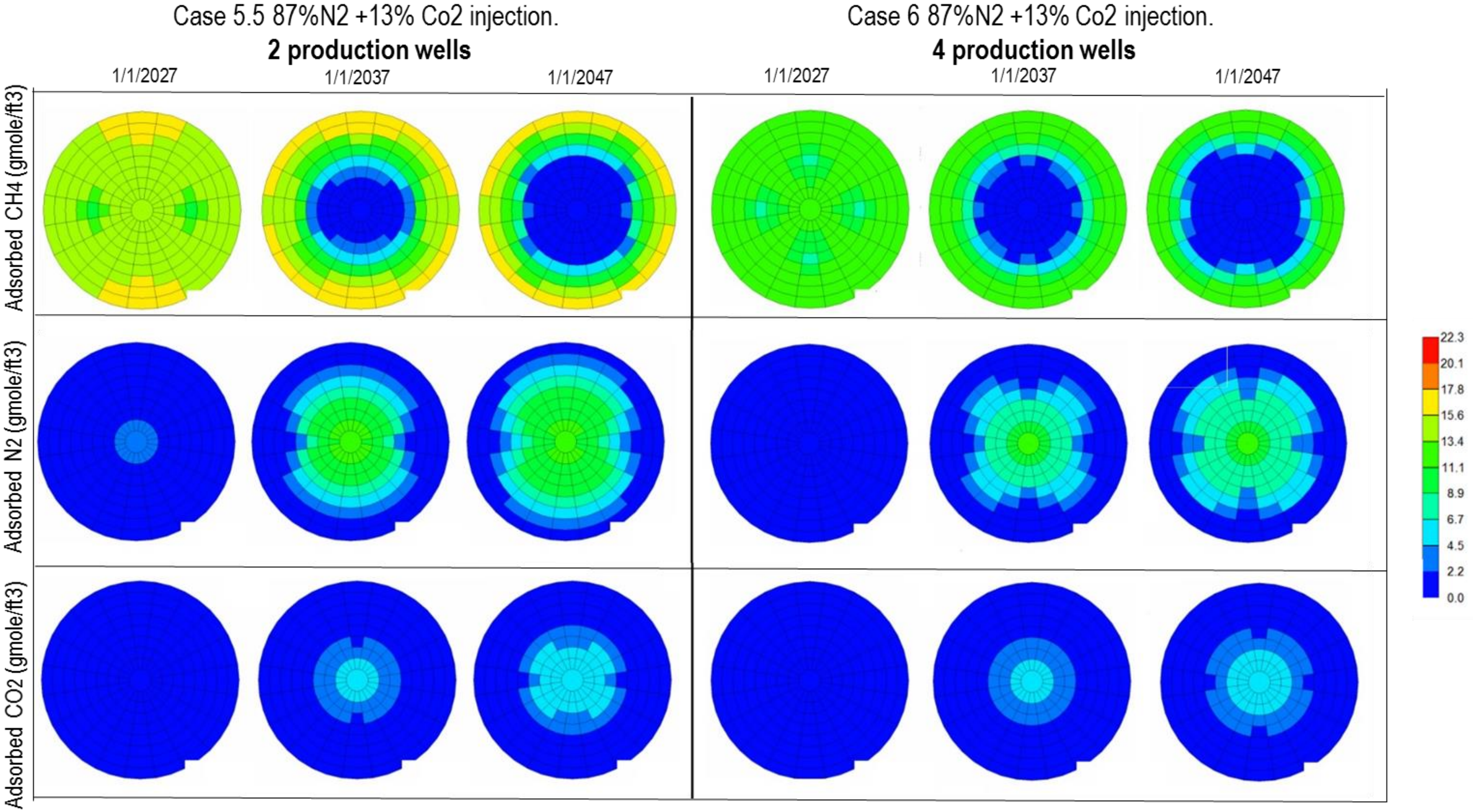


Gas mole fraction. Summary for case 4



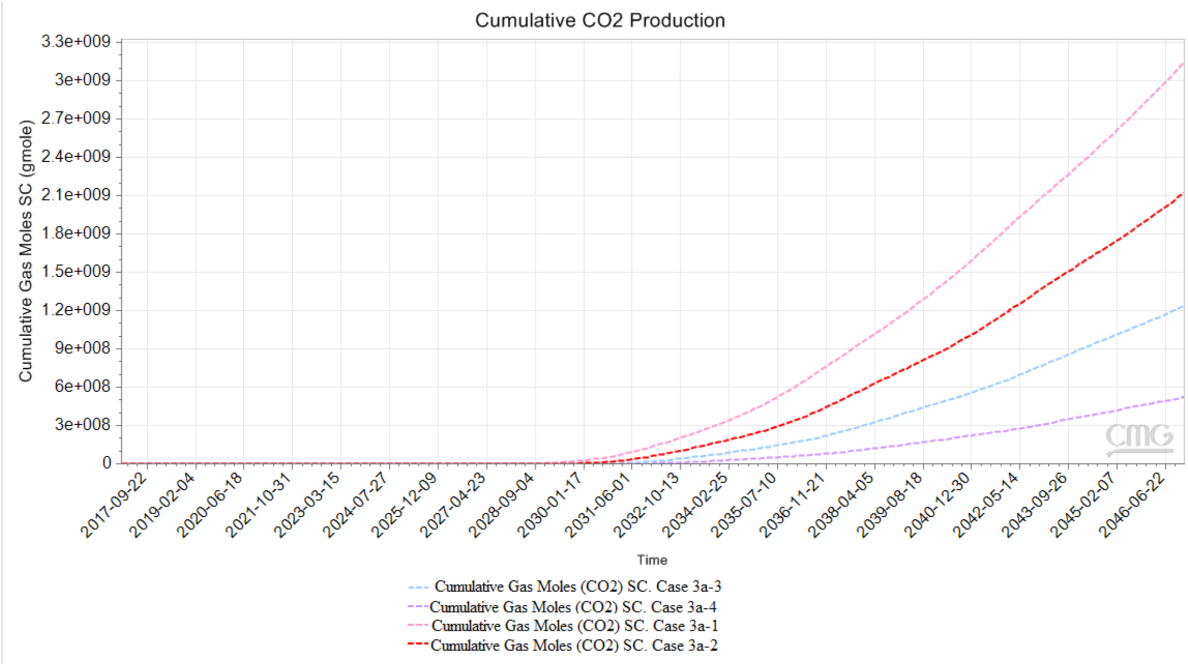
Cumulative CO2 production, Summary

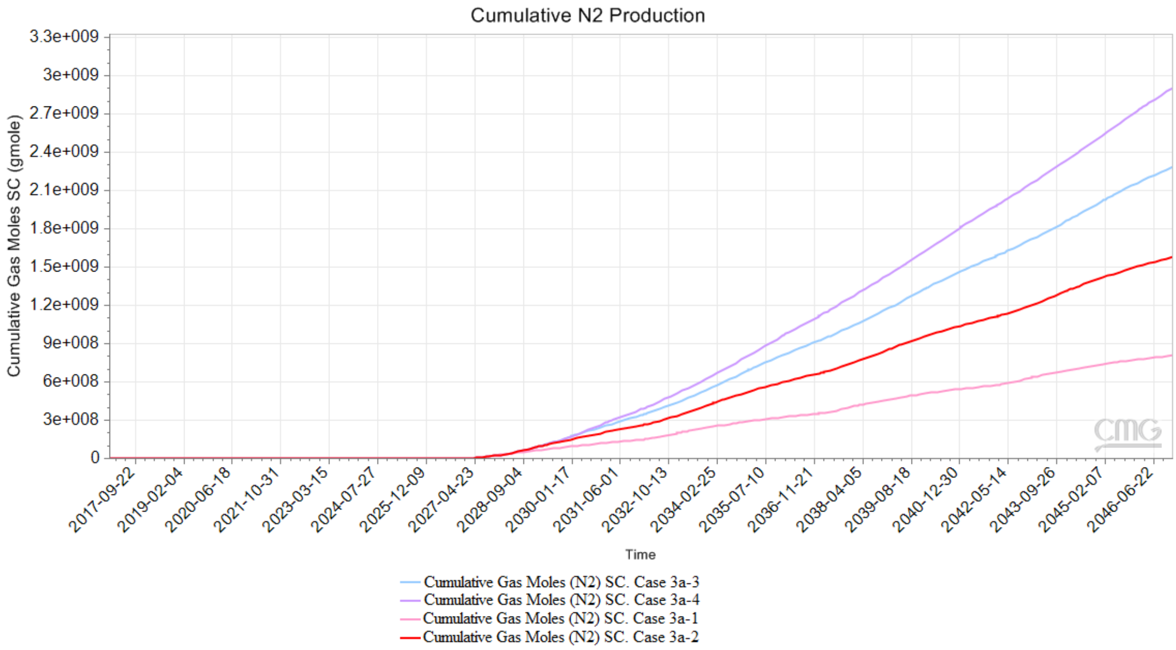
Appendix B



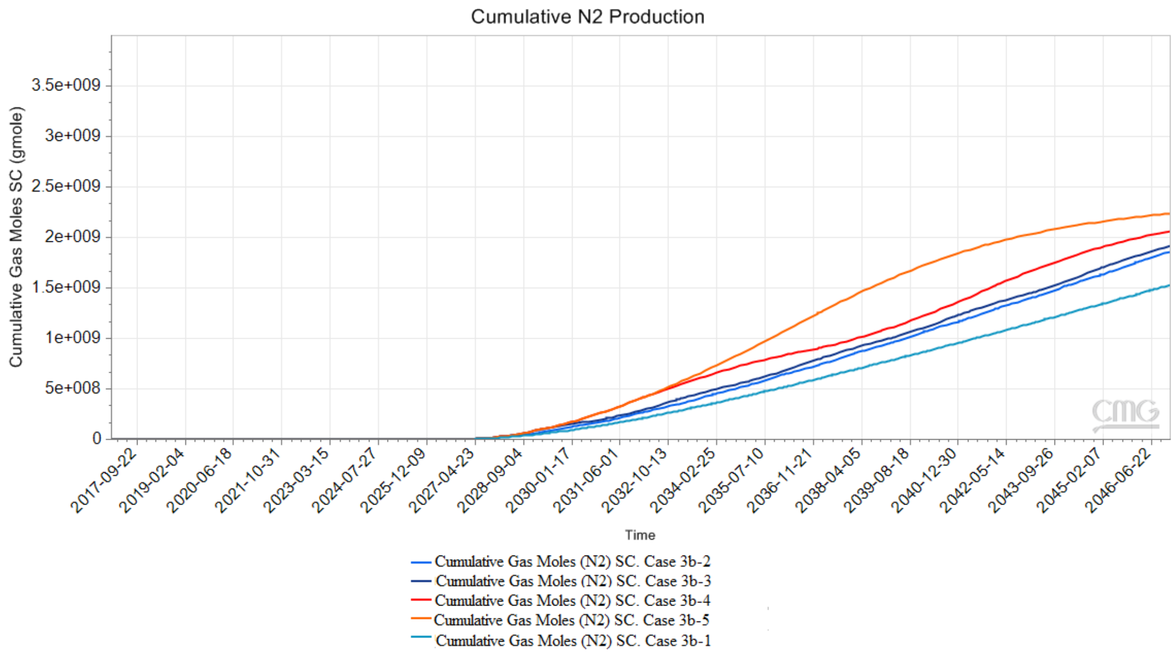
Case 5.5 and Case 6 adsorption behaviour comparison

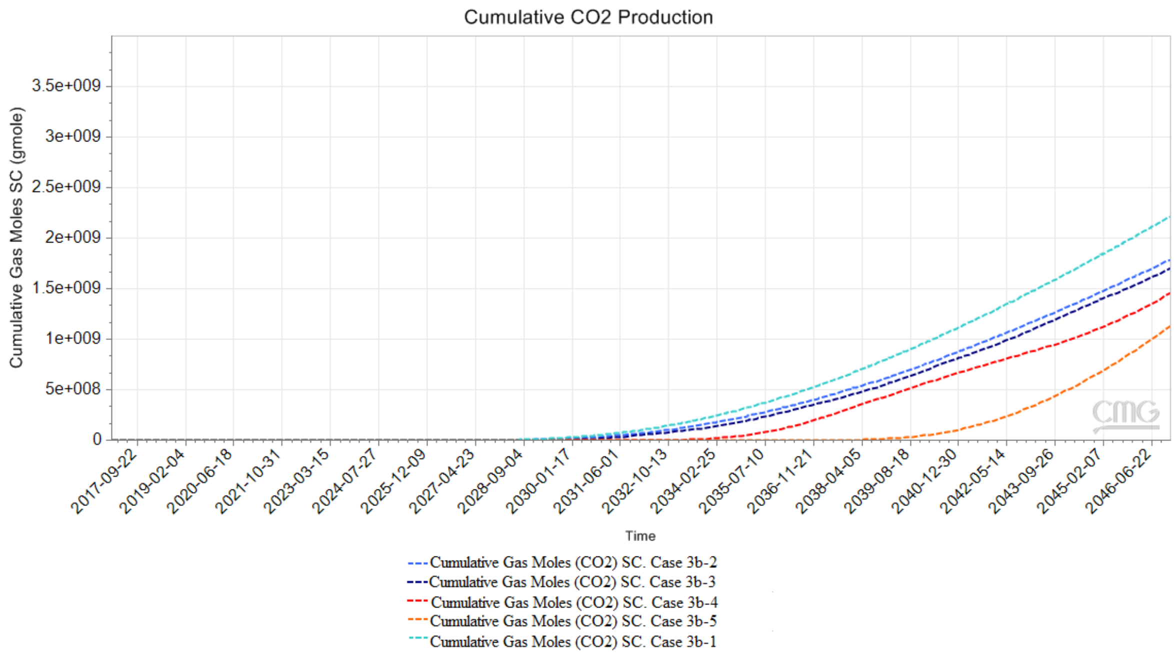
Appendix C



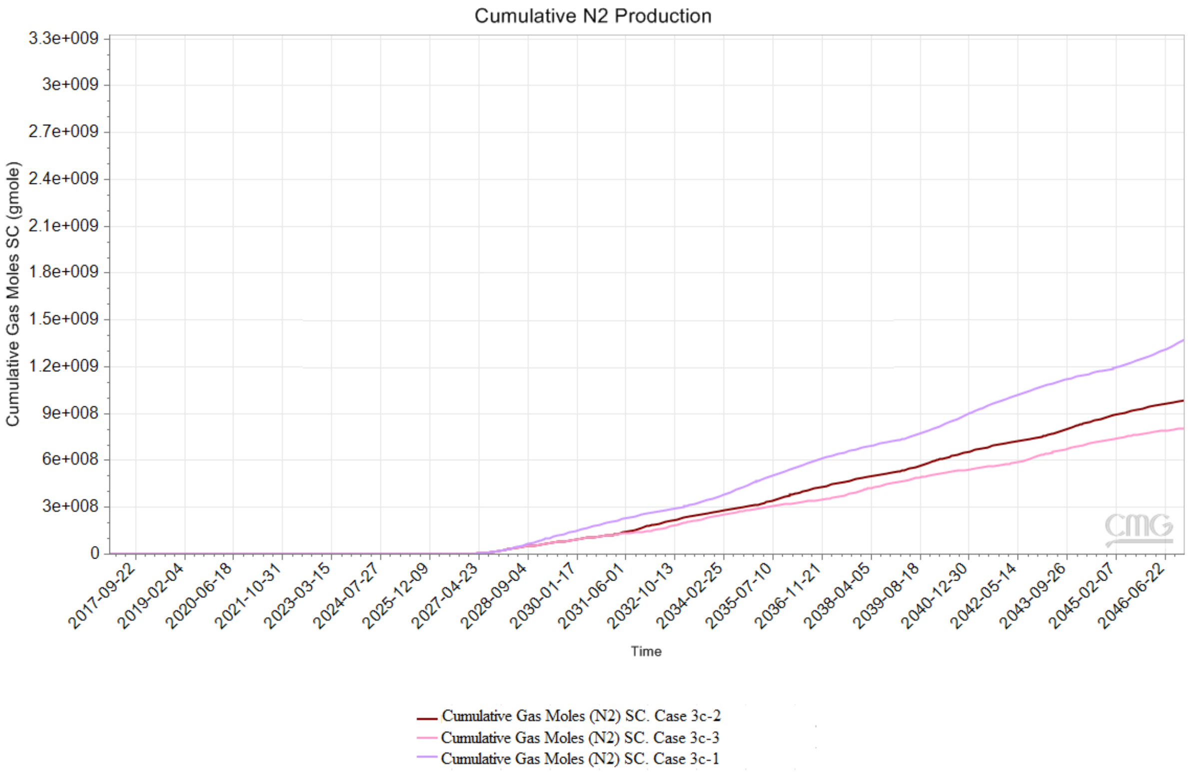


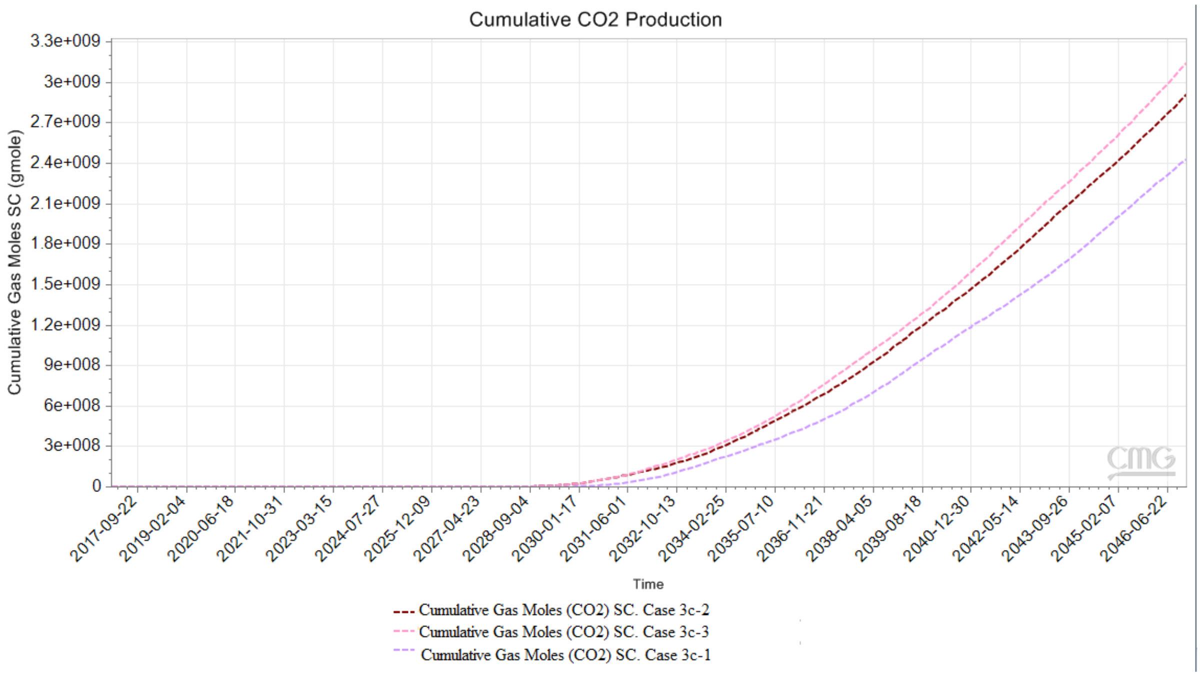
Case 3a. CO_2 and N_2 cumulative production





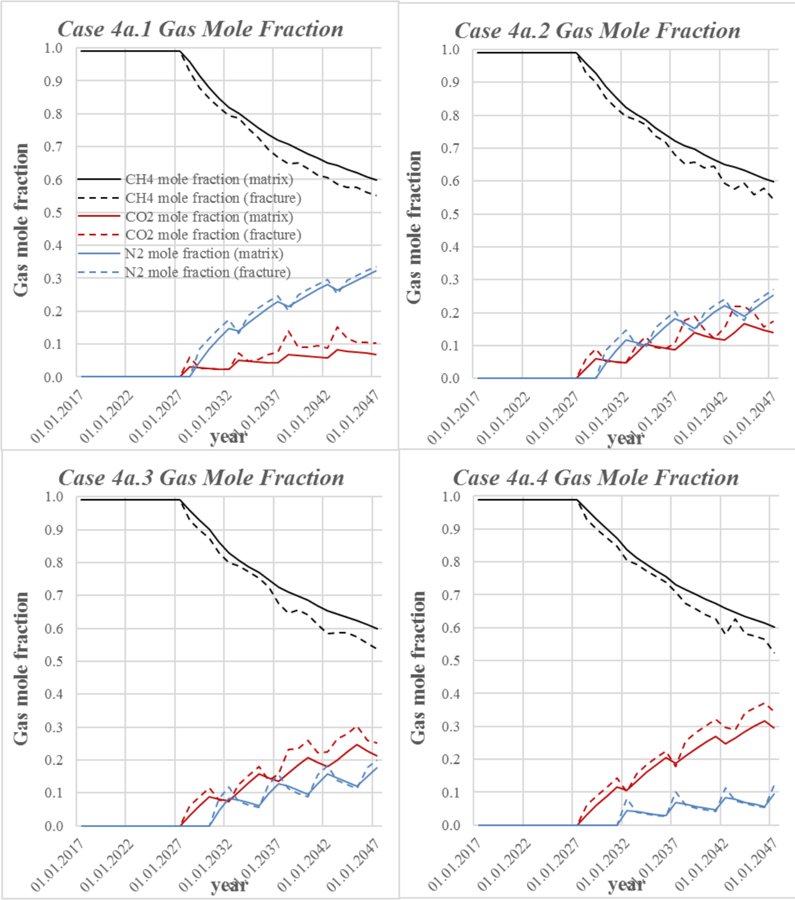
Case 3b. CO_2 and N_2 cumulative production



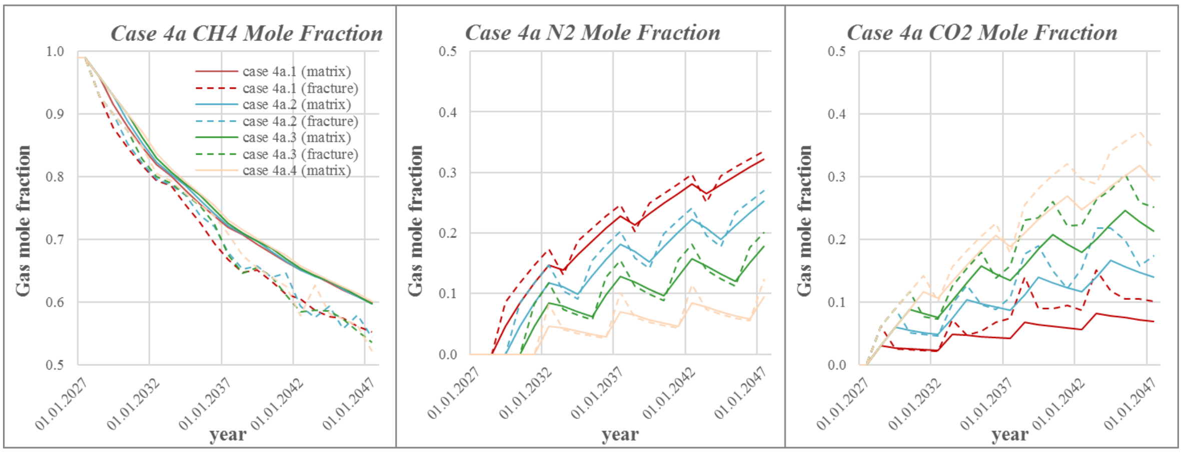


Case 3b. CO_2 and N_2 cumulative production

Appendix D



Gas mole fraction. Case 4a



Gas mole fraction. Case 4a – Summary

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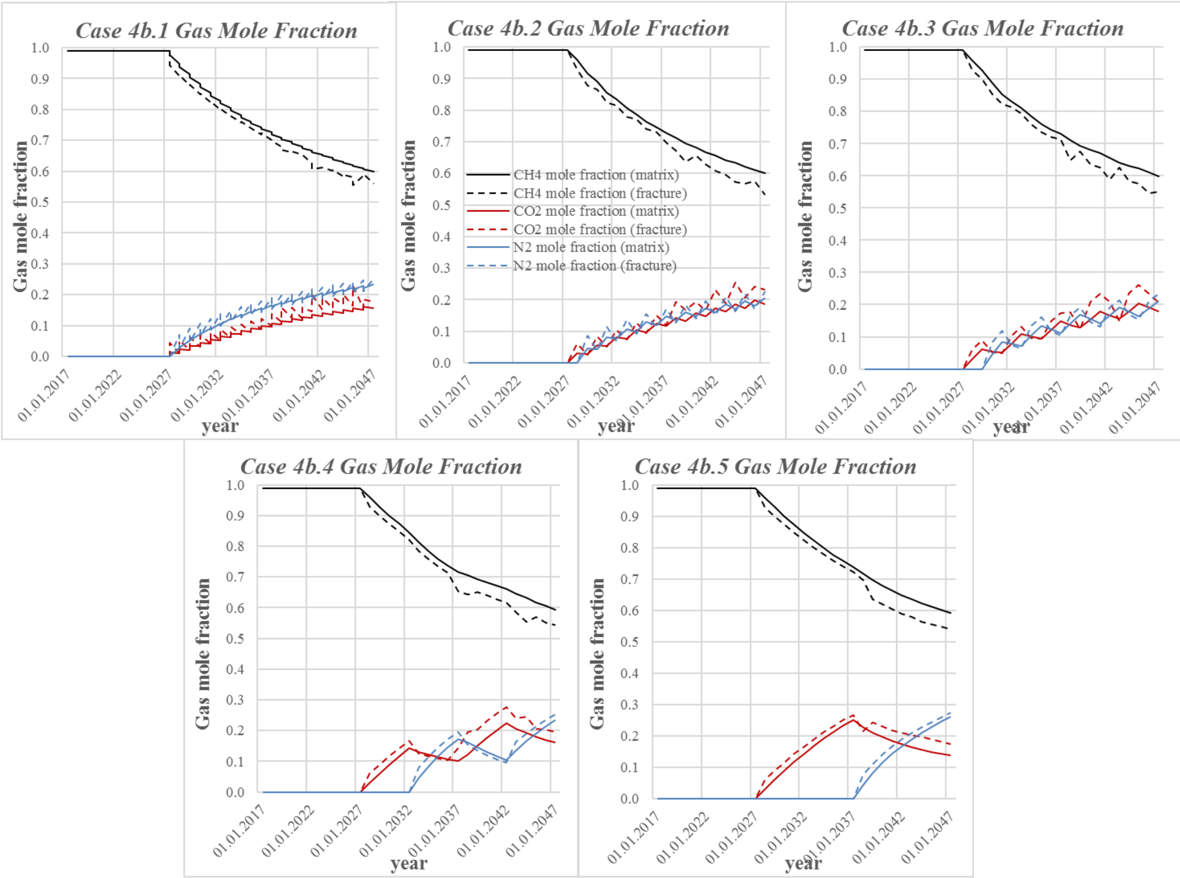
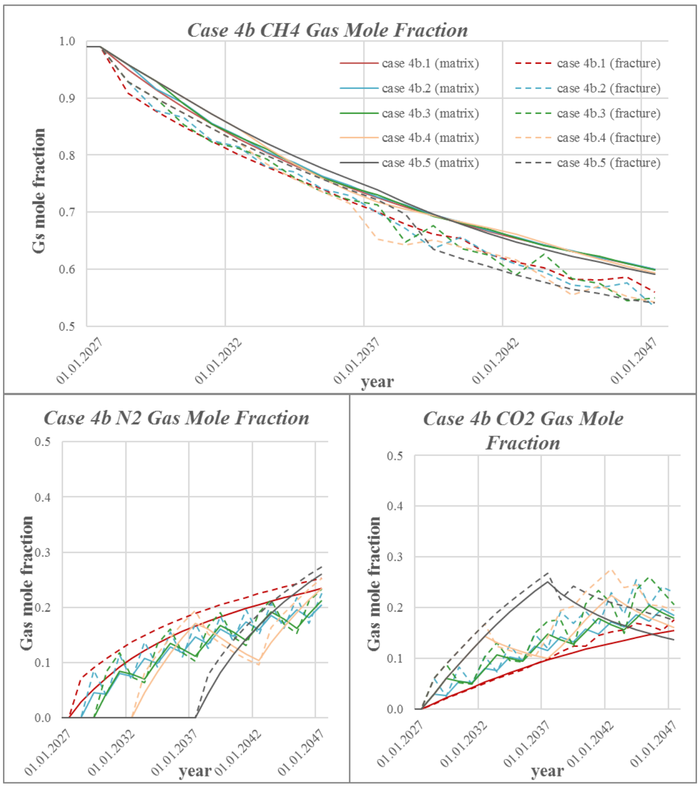
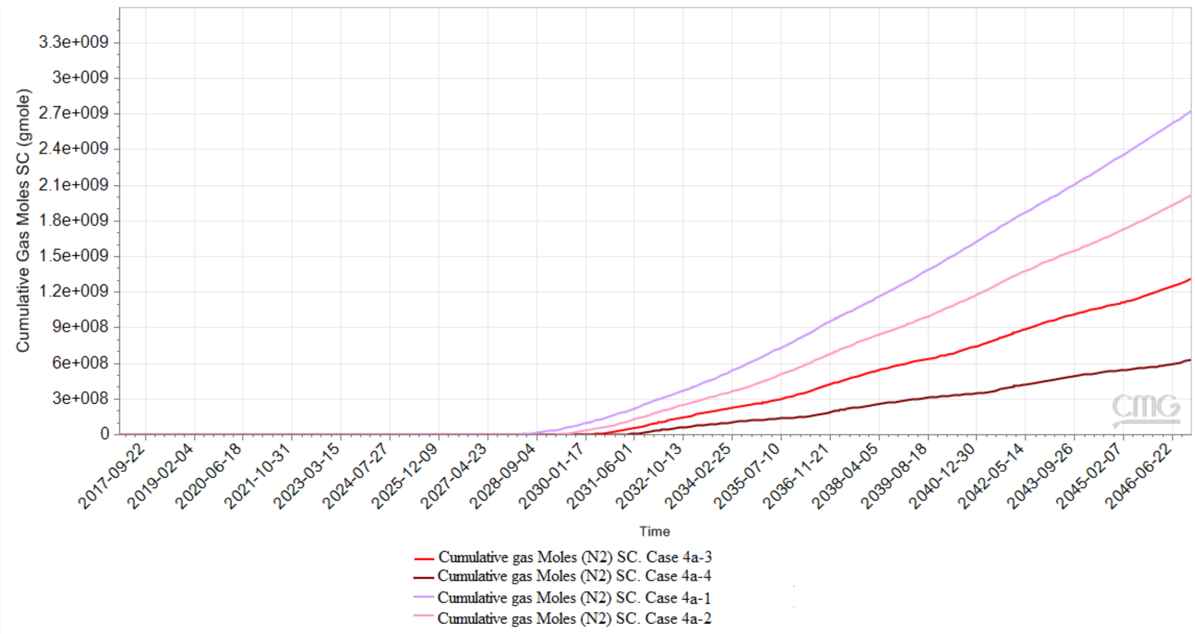
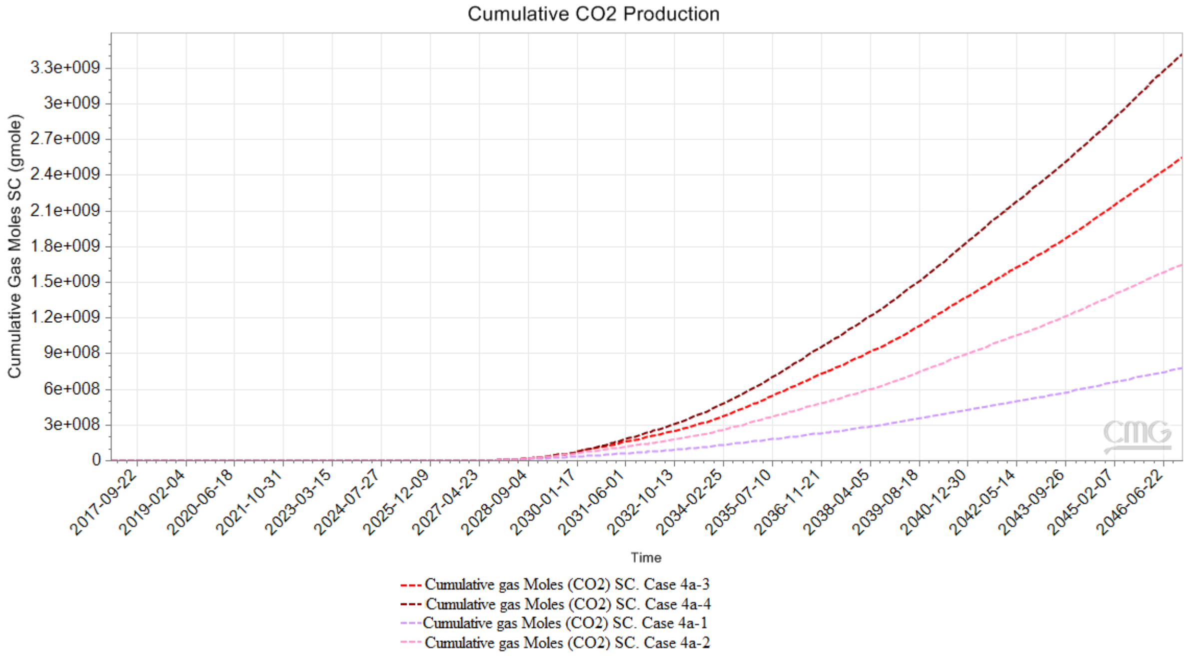


Gas mole fraction. Case 4b

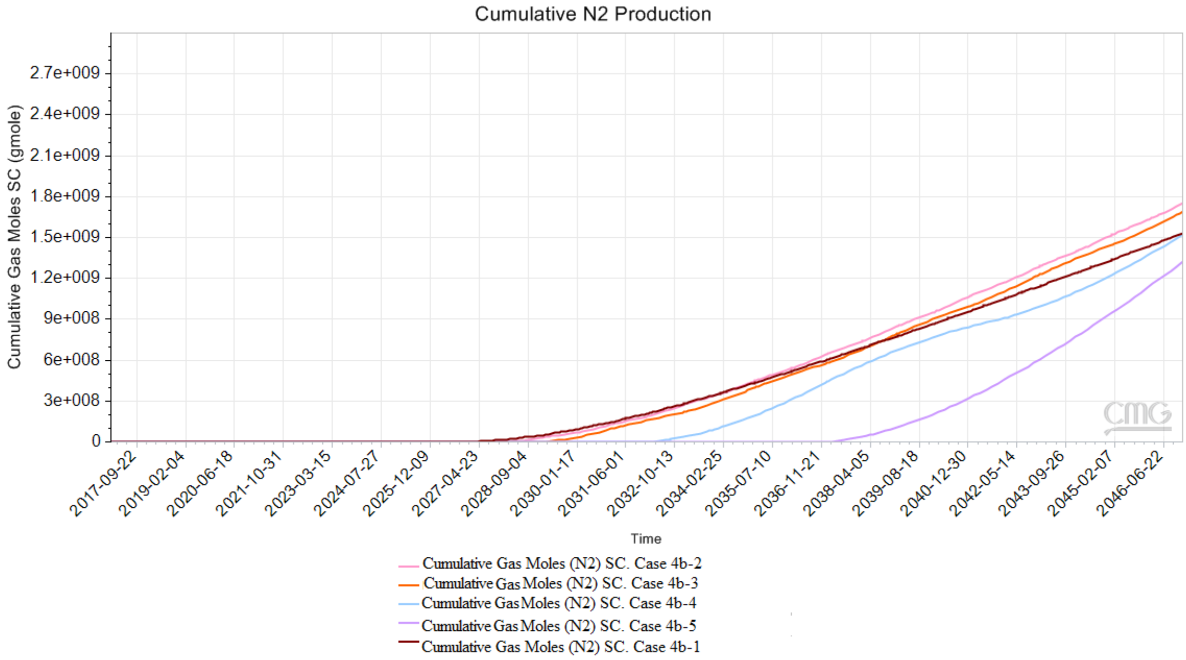


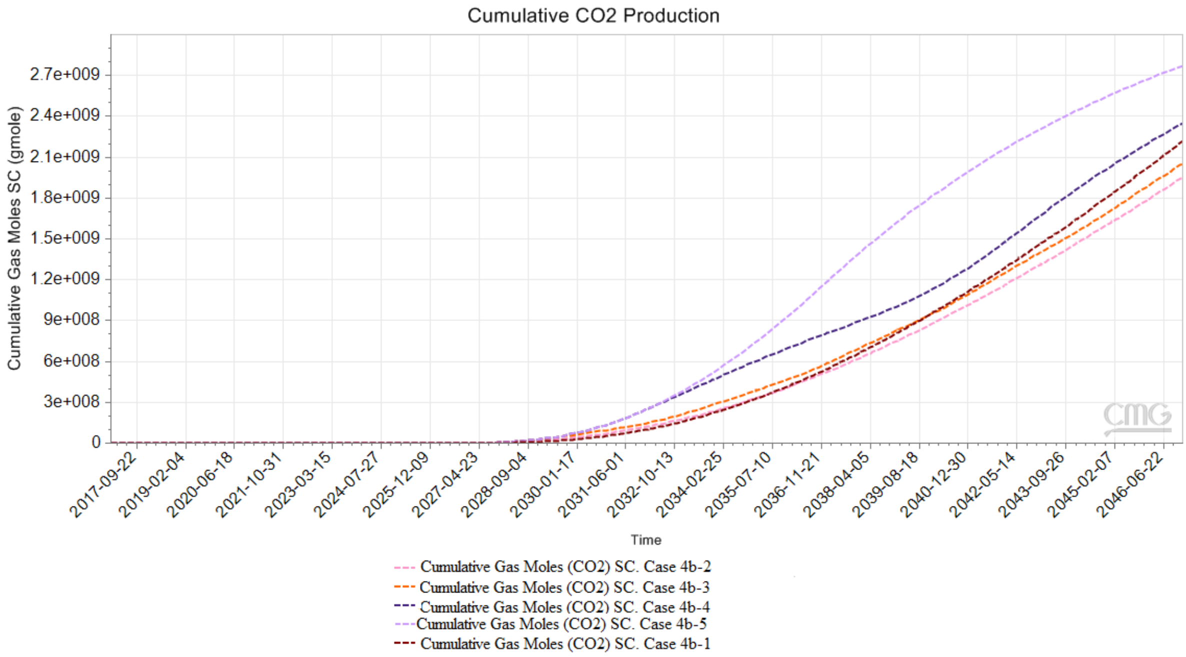
Gas mole fraction. Case 4b – Summary



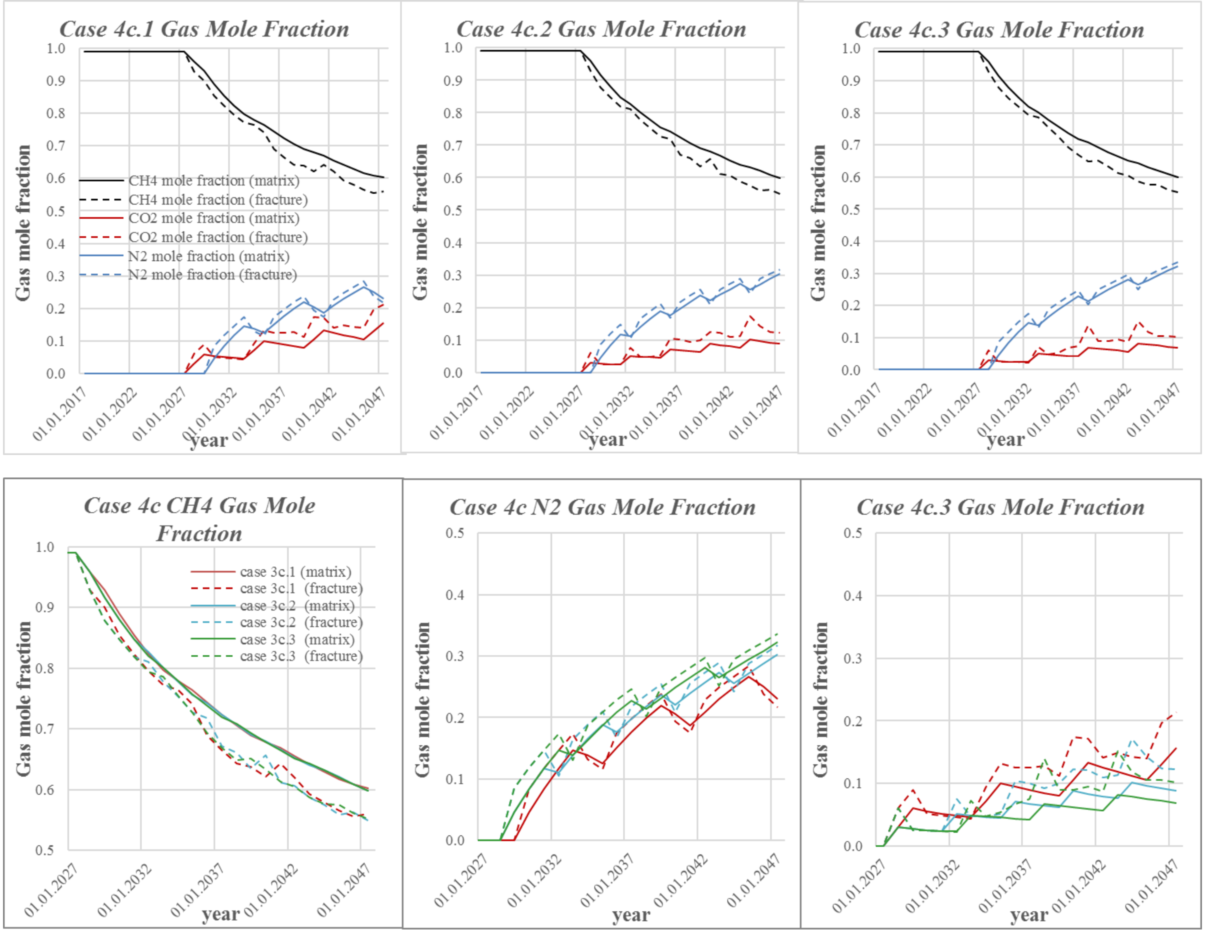


Case 4a. CO_2 and N_2 cumulative production

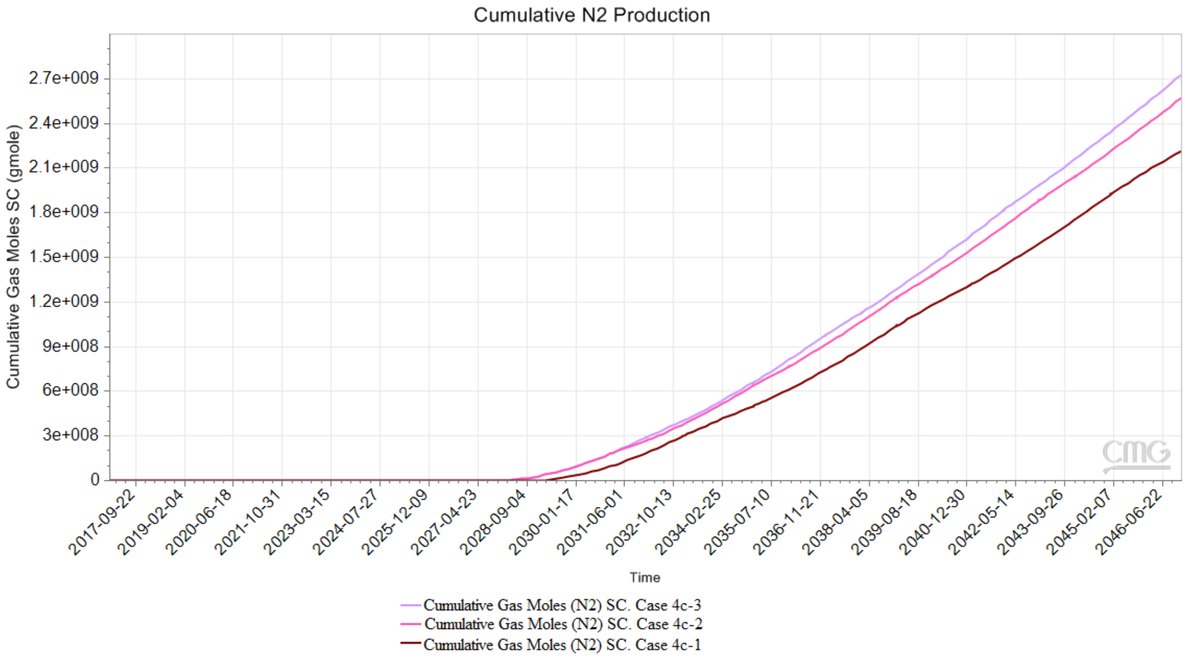


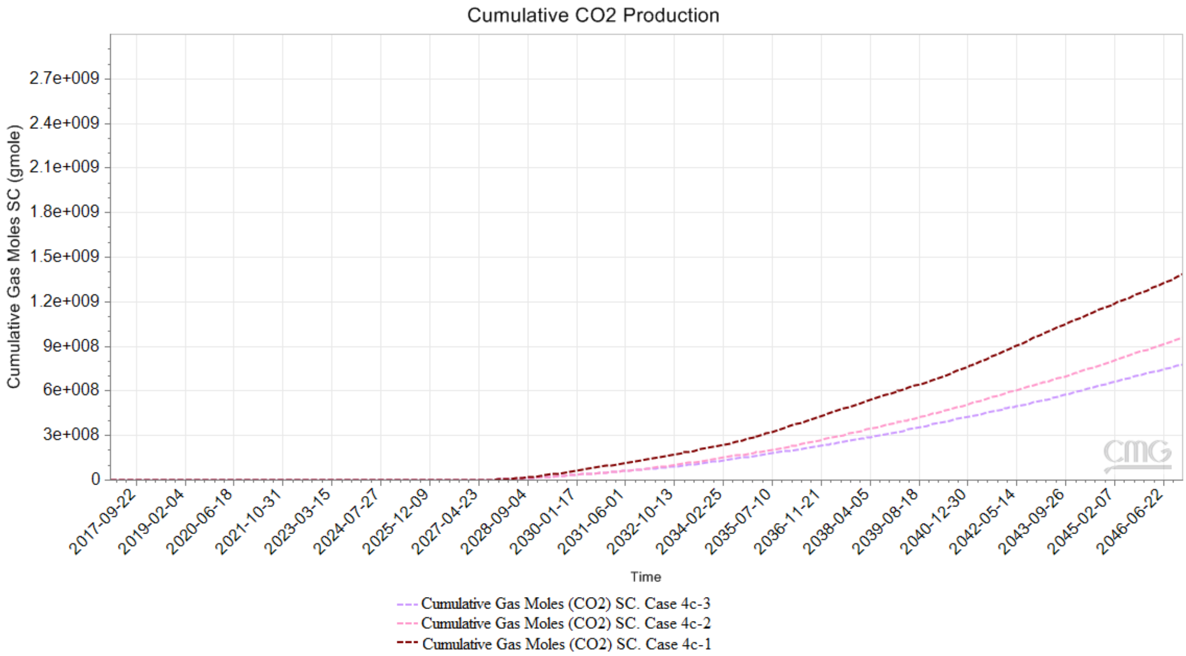


Case 4b. CO_2 and N_2 cumulative production



Gas mole fraction curves for additional case 4





Case 4c – CO_2 and N_2 cumulative production