Fracture permeability and relative permeability of coal and their dependence on stress conditions

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Determination of petro-physical properties of coal bed methane (CBM) reservoirs is essential in evaluating a potential prospect for commercial exploitation. In particular, permeability of coal and relative permeability of coal to gas and water directly impacts the amount of hydrocarbons that can be ultimately recovered. Due to the complex and heterogeneous nature of coal seams, proper relative permeability relationships are needed to accurately describe the transport characteristics of coal for reservoir modeling and production forecasting. In this work, absolute and relative permeability of different coal samples were determined experimentally under steady-state flowing conditions. Multiphase flow tests were conducted using brine, helium and carbon dioxide as the flowing phases under different magnitudes of confining and pore pressures. Results indicate that effective stress (Confining pressure – average pore pressure) has a significant effect on both absolute and relative permeability of coal. With increases in effective stresses, the absolute permeability decreases. Effective permeability and relative permeability, as well as the cross over point and the width of the mobile two-phase region decrease as the effective stress increases. In addition, the

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mobile range of gas and water in the coal samples investigated corresponds with water saturations above 50%, irrespective of the base absolute permeability of the sample. In brine-carbon dioxide two-phase flow experiments, the effect of carbon dioxide adsorption was observed as effective permeabilities decreased in comparison to the helium-brine permeabilities at the same flowing ratios. As a result, relative permeability characteristics of CBM systems were found to be insufficiently represented as sole functions of fluid saturation. Field scale simulations of primary recovery from CBM systems using variable, stress-dependent relative permeabilities, showed a significant decrease in cumulative gas recovered. A multi-dimensional correlation between relative permeability, fluid saturation and specific surface area of the cleat network is proposed as a continuation from this work in order to account for stress-related changes in cleat network connectivity.

1. Introduction

Methane production from coal seams has been practiced for more than half a century and successful commercial exploitation of coal bed methane systems has been witnessed on a global scale, especially in the United States. It is estimated that the global methane reserves from coal seams can be up to 9,500 Tcf and in the US up to 3,000 Tcf [1]. For reservoir engineering applications coal seams are treated to be dual porosity in nature having a tight matrix and a well defined natural fracture or the cleat system. Coal seams undergo a multi-mechanistic depletion process [2] where gas desorbs and diffuses from the matrix into the natural fractures and from the natural fractures it flows to the wellbore. Generally when gas desorbs from the micropores, the matrix shrinks which leads to an increase in permeability [3] and when gas adsorbs, the permeability decreases due to matrix swelling. Hence the interaction of gases with the observed changes in coal permeability accompanied by shrinkage/swelling characteristic of coal is a complex phenomenon. Hence research interest has increased in the recent past to study and understand the behavior of different types of coals for long term reservoir monitoring and management. Among these, research investigations aimed at understanding the relative

permeability characteristics of coal seams which primarily describes the flow of water and gas in the cleat or the fracture network has been very minimal [4], [5], [6], [7], [8], [9], [10], [11].

The major uncertainties with respect to relative permeability measurements were attributed to sample size, low absolute permeabilities, measurement methods, presence of minerals, experimental conditions and hysteresis effects. Even among samples from the same basins, there were significant differences in measured relative permeability values underlining the complex nature of coal. Since fractures in coal serve as the primary channels through which gas and water flow, changes in fracture apertures due to changing stress conditions could be significant to affect gas and water flow in fractures. Some of the variations in the observed relative permeabilities in these studies could be due to not accounting for the effects of effective stress on two – phase flow in the fracture network. Coal being a naturally fractured formation exhibits strong dependence of permeability on stress conditions [12], [13]. Effective stress, which is the difference between the overburden stress and the pore pressure, is the one that actually controls the permeability and coal's permeability is strongly affected by effective stress [14]. Although coal's absolute permeability variation with effective stress/sorption phenomena has been well studied and understood [15], [16]; [12]; [17], [18], [19] the relative permeability behavior of coal in response to changes in effective stress/sorption phenomena is difficult to predict. Detailed description of multiphase flow in fractures and the effect of net overburden stress on two phase flow have not been addressed before. Furthermore, relative permeability relationships are hysteretic in nature and non- unique as they are affected by saturation history (drainage and imbibition cycles). Traditional representation of fracture relative permeabilities as functions of fluid saturations as inputs to CBM simulators can be insufficient to capture the dynamic variations of gas and water flow happening in the fracture network due to varying stress conditions. Current CBM models (dual porosity models) use relative permeability relationships that span the entire window of saturation or straight line relative permeability relationships for describing the flow of gas and water in the fractures. Assuming a straight line relative permeability description as inputs in dual porosity reservoir simulators for describing the multiphase flow in fractures can lead to an oversimplification. Therefore more experimental investigation is needed that explicitly determines the effect of effective stress on the transport of water and gas in the coal fractures. The primary objectives of this work are threefold. Firstly, to determine the effect of effective or net stress on the flow of gas and water in coal fractures, Secondly to identify any observable trend on the relative permeability behavior due to changing stress conditions and thirdly to conduct simulation studies based on the experimental results.

2. Experimental Set-up and Procedure

The samples used in the present study are coal cores predominantly obtained from bituminous coal seams in Marshall County, West Virginia. Samples 1, 2 & 3 were cored from wells at depths of 600ft to 700ft. Sample 4 was prepared from a coal block originally obtained from a coal processing facility in Clearfield County, Pennsylvania. Sample 1, 2 & 3 were subjected to petrographic and proximate analysis. Table 1a gives the dimensions of the samples. Tables 1b and 1c summarize the results of petrographic and proximate analysis. The mean maximum vitrinite reflectance ($R_{\max}$) of these samples is 0.75% and based on the ASTM coal rank classification scheme they can be classified as high volatile A bituminous coal. All the samples had to be artificially fractured to get absolute permeabilities greater than 1 md so that they are

suitable for single phase and multiphase flow studies. X-ray computed tomography was primarily used for in situ fluid saturation distribution determination. The X-ray scanner used in this work is a 'Universal HD-350E' medical CT scanner, which has a series of detectors arranged on a circumference with the X-ray source rotating around the object positioned in the center. The resolution used here is $0.195\text{mm} \times 0.195\text{mm}$, with a slice thickness of 1mm and a detection frame of 512×512 voxels. Figure 1 shows the experimental set up for conducting flow experiments. Gas and brine are taken into the 'pre – saturation unit' which is a pressure vessel capable of being operated up to a maximum pressure and temperature of 3000 psi (21 MPa) and 150 C respectively. Temperature during the experiments was 20 ± 2 C. In this pressure vessel, (pre-saturation unit) brine and gas are allowed to equilibrate and then are drawn separately by pumps and injected in the core holder where the sample is confined under hydrostatic loading. The fluids exiting the core holder are received by the back pressure pump operated at a constant pressure receive mode of operation so that a constant back pressure is maintained. The back pressure pump is connected to the pre-saturation unit. The fluids received by the pump are delivered into the pre-saturation unit so that the pressure in the system is maintained and the fluids are recirculated in a closed loop. All the injection pumps (gas transfer pump, gas injection pump, brine injection pump) are operated under constant flowrate injection mode.

3. Single-phase tests – Absolute permeability experiments

Single phase permeability tests were conducted to understand the impact of effective stress on the fracture permeability of the coal samples used in this study. Figure 2 shows the behavior of fracture (cleat) permeability in sample 1 (length: 3.25") with changes in effective stress. Several different trials were conducted in the sample using brine (5% sodium iodide) as the flowing phase to understand how the fracture permeability changed with the application of stress and also with time. Trial 1: Initial absolute fracture permeability determination by using water as the flowing phase, Trial 2: Absolute fracture permeability determination after the flow direction in the sample was reversed, Trial 3: Absolute fracture permeability determination after the flow direction in the sample was restored, Trial 4: Final determination of fracture permeability after the above three trials. One can see from Figure 2, the fracture permeability of the sample continuously decreases with time and after the fourth trial, the fracture permeability reduction is almost an order magnitude lower from the initial permeability. This qualitative behavior of permeability decline with effective stress has been reported in the literature [20], [21] and can be approximated to be exponential, although the behavior flattens out with time and could become independent of stress. The entire duration of the tests starting from a fresh sample until the completion of the 4th trial is about 7 weeks. During these trials, the sample was subjected to alternating stress loading and unloading cycles and, with time and repetitive trials, the fracture permeability keeps decreasing. This indicates that permeability continuously decreases with repeated experimentation (single/multiphase flow tests) and it is difficult to restore it to the original absolute permeability of the sample. Each time the core was stressed and de-stressed by the application/removal of confining pressure, the pore volume compressibility or the fracture compressibility was affected, and it subsequently changed the permeability of the sample irreversibly. Table 2 shows the observed pressures and the corresponding flow rates used for the 4 trials.

4. Multi-phase tests – Relative permeability experiments

Multiphase flow tests were carried out in samples 2, 3 and 4. Helium and brine (5% sodium iodide) were used as the flowing phases in samples 2, 3 & 4 and brine and CO₂ in sample 4.

Helium-brine two-phase flow experiments were done to establish a baseline of the relative permeability observations without the influence of any sorption related effects. For each of the combination of flow rates of brine and gas, sufficient time was allowed until steady state conditions were reached (pressure drop across the sample and the flow rates became constant) and the entire sample was X –ray CT scanned in the axial direction to record the saturation distributions of the gas and water in the fractures at that point in time. The effective permeability to gas and water were calculated using Darcy's law. The effective permeabilities of gas (Helium) and brine at the two different confining pressures used for sample 2 and sample 3 are plotted in figure 3 and figure 4 respectively. Tables 3 and 4 show the set flowrates and recorded pressures for sample 2 and sample 3. As the confining pressure is increased the magnitude of effective permeability to gas and water decreases. Figure 5 and figure 6 depicts the effective permeability curves for sample 3 where the differences due to changes in confining pressures can be more explicitly seen. With more confining pressure, the movement of water is reduced and is retained in the fractures, resulting in higher immobile water saturation. Also the cleat network geometry could be influencing high water retention at higher confining pressures. From figures 5 and 6 one can observe that the irreducible water saturation increases and the phase cross over point and the two-phase flow region decrease as we move from a lower confining pressure to a higher confining pressure. Figure 7 shows a set of the X- ray CT scan images taken at different saturation states and the last image shows the sample at irreducible water saturation conditions.

From these observations in this type of coal, during the simultaneous flow of gas and water in the fracture network, the movement of gas is greatly affected in the presence of mobile water. Each of the data points shown in figure 5 and figure 6 is at a different effective stress depending on the prevailing pore pressure and the corresponding confining pressure applied. Figure 8 and figure 9 depict the same information shown in figure 5(sample3) and figure 6(sample 3) but the data points are grouped together based on a range of effective stresses as shown in the legend. The color coding to show the effective stress as the third parameter varies from a cooler color to a warmer color to show increasing levels of effective stress. In Figure 8 and figure 9 each color contour corresponds with a single set of effective permeabilities for a particular effective stress range. One can see that for any value of saturation, there can be more than one value of effective permeability, depending on the effective stress. Now using the values of k_{weff} 's for different effective stresses and saturations, an effective permeability surface has been generated as shown in figure 10. For the same sample 3, a similar surface plot can be generated for the fracture effective permeability of coal to gas as shown in figure 11. This implies that there can exist a family of effective permeability curves so that the effective permeability of coal to gas and water could be represented as multi-dimensional entities instead of expressing them as functions of saturations alone. From the above two effective permeability surfaces shown, an equation of the

surface can be generated which relates the effective permeability as a function of effective stress and fluid saturation. This relationship can be used in reservoir models using an appropriate formulation to relate the relative permeability changes as a function of net stress and saturation.

To understand how the effective permeability of coal to gas and water changes by the introduction of CO₂ as the gas phase, CO₂-brine two-phase tests were conducted in sample 4. Tables 5 & 6 shows the flowrate and pressure measurements at confining pressures of 2.28 MPa and 4.1 MPa respectively. The experimental variables and conditions were maintained similar to that of the helium and brine two phase flow tests. Prior to conducting CO₂-brine experiments in this sample, He-brine two-phase flow experiment was carried out to obtain two-phase data without any sorption/swelling effects that will enable to compare the CO₂-brine data. Contrary to the relative permeability measurements with He and brine as the flowing phases, the CO₂-brine experiment was not scanned for X-ray CT imaging for estimating the phase saturation distributions. Figures 12 and 13 shows the comparison between the effective permeability of coal to water and gas when the confining pressure was 2.3 MPa and when brine - He and brine - CO₂ were used as the flowing phases. Similarly figures 14 and 15 shows the effective permeability of coal to water and gas when the confining pressure was 4.1 MPa. From figures 12, 13, 14 and 15 one can observe that the effective permeabilities to water and gas obtained from the CO₂ - brine test are lower in comparison to the effective permeabilities when brine and helium were the flowing phases. This implies that there is a definite reduction in permeability of the phases when CO₂ is used. The other observation to be identified is when this reduction in permeability happens as a result of change in effective stress field due to CO₂ adsorption domination. Figures 16 and 17 shows the effective permeability of coal to CO₂ as a function of effective stress.

Based on figures 16 and 17 one can observe that as the effective stress decreases, the permeability increases and after a certain point, the permeability starts to decline indicating the effect of swelling resulting in subsequent permeability reduction.

5. Reservoir simulation studies for primary CBM recovery analysis

To test the impact of the experimentally obtained stress dependent relative permeability relationships on primary CBM recovery, a hypothetical CBM model was built and modeled. In this work, an in-house finite difference based compositional coal bed methane simulator, PSU – COALCOMP [22],[23],[24] and a commercial compositional simulator, CMG-GEM(Computer Modeling Group, Calgary, Canada) were used for the simulation study. Two broad modeling exercises were done. First where sorption related primary gas recovery was ignored and in the second one where it was considered. The Palmer & Mansoori model [12] is used here to describe the additional gas production that happens due to shrinkage of the coal matrix. Table 7 shows the reservoir, rock and fluid properties used for building the model. Table 8 shows the description of the various scenarios employed in the simulations. The reservoir model has a homogeneous distribution of properties with a single well producing at a specified bottom-hole pressure of 0.1 MPa.

In the first scenario, ‘X’ type relative permeability curves are used as inputs (fracture relative permeability description) to predict the total methane produced as a function of time. This base

case represents the methodology used when fracture relative permeability relationships are unknown. The net stress acting on a reservoir changes with time and depletion. To bring into perspective the effect of net stress on the movement of gas and water in coal fractures, in the second scenario, relative permeability relationships (shown in Tables 9 and 10) were used. The relative permeability descriptions shown in Tables 9 and 10 were derived from the effective permeabilities shown in figures 8 and 9 at the corresponding effective stress ranges of (1.4-1.7) MPa and (1.7-2) MPa respectively. To use the relative permeability relationships described in Tables 9 and 10, times at which the effective reservoir pressure fell between the effective stress ranges were identified from the base case simulation (scenario 1) where 'X' curves are used. It is assumed from time zero to the time at which the effective reservoir pressure reaches 1.4 MPa (time at which the first experimentally obtained relative permeabilities are used – Table 9), the depletion can be described by 'X' type relative permeability description. Scenario 3 and 4 describe similar scenarios described in scenarios 1 and 2 but with the inclusion of the desorption model to account for the changes in gas production due to matrix shrinkage.

Figure 18 shows a comparison between the cumulative gas production obtained from all the four scenarios. As seen, the cumulative gas production obtained by using multiple or stress dependent relative permeability curves (scenario 2) is significantly less in comparison to the production generated by the use of one single relative permeability relationship for the entire period of production (scenario 1). The cumulative gas production curve starts to deviate from the scenario 1 curve at the time when the first experimentally obtained relative permeability curves (Table 9) are used when the effective reservoir pressure is between 1.4 and 1.7 MPa. When the effective reservoir pressure exceeds 1.7 MPa, the curves described in Table 10 are used and this set of relative permeability curves are maintained until the end of the simulation run. In scenario 3 when the gas produced due to matrix shrinkage is included, the cumulative gas production in this case is higher in comparison to scenario 1. In scenario 4, the cumulative gas produced is slightly higher than the corresponding scenario 2 but not as significant as the difference between scenarios 1 and 3. There is a higher difference in the cumulative gas produced when the gas production due to shrinkage is accounted when comparing between scenarios where 'X' type curves are used. In the case where multiple relative permeability relationships are used depending on the prevailing effective stress in the reservoir, based on the difference in the cumulative gas produced, stress dependant relative permeabilities have a stronger effect in comparison to the effect of matrix shrinkage which drives down the production rate. Based on the different scenarios considered and evaluated, the significance of using stress dependent relative permeabilities in dual porosity systems has been demonstrated through this approach. However a more robust modeling study can be done by tying the reservoir simulator with a geo-mechanical model.

6. Conclusions

The exponential trend of the decline of absolute fracture permeability with effective stress observed in these samples is an indication that fracture permeability is strongly affected by effective stresses. We observe with time and repeated experimentation, this observed decline behavior becomes less evident and at some point the change in permeability becomes independent of effective stress.

As the effective stress increases, the effective permeability of coal to gas and water decreases and in general is depressed when compared to conventional reservoirs. The lowest effective permeabilities are observed at the highest effective stress and the relative change in the effective permeabilities are more pronounced for the water phase in comparison to the gas phase as we move from one range of effective stress to another.

A best fit effective permeability surface can be generated as a function of effective stress and saturation from 2D plot of effective permeability as function of effective stress and fluid saturation. This relationship can be used in reservoir models using an appropriate formulation to relate the relative permeability changes as a function of net stress and saturation. The concept of expressing relative permeabilities as multi-dimensional functions to address their non-uniqueness (due to the dependence of relative permeability on saturation history) has been demonstrated before but with using pore network modeling data [25]

Comparison between He-brine and CO₂-brine two phase flow experiments indicate that two-phase flow descriptions provided as inputs to CBM simulators have to be modified specifically. This will enable modelers to account for effect of the interaction of different gases in coal and to accurately predict the gas and water flow in the fractures.

Based on the influence of effective stress on the flow of gas and water in coal fractures, these observations can be tied to a mechanistic description of two-phase flow behavior linked to changes in fracture aperture or the specific surface area of the aperture. More experimental studies are needed to confirm this.

The concept of using multiple relative permeability relationships depending on the effective stress regime in CBM reservoir models can affect the recovery of gas to different extents and the effect may be significant. This approach maybe more suitable so that reliance on one particular set of relative permeability relationships, that are assumed to be constant during the entire producing life of stress sensitive reservoirs like coal bed methane reservoirs, would not be erroneously used.

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Abbreviations

daf	dry ash free basis
mmc	mineral matter containing
mmf	mineral matter free basis
P _{eff}	Effective Stress (MPa)

k_{weff}	Fracture effective permeability to water (mD)
k_{geff}	Fracture effective permeability to gas (mD)
k_{abs}	Absolute fracture permeability of coal to water (mD)
P_{conf}	Confining pressure (MPa)
P_{avg}	Average reservoir pressure (MPa)
MPa	MegaPascals
mD	milliDarcy
mD	$= 9.869233 \times 10^{-16} \text{ m}^2$

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Figure 1. Experimental design for single/multiphase flow tests

Figure 2. Variation of fracture permeability with net effective stress – Sample 1

Figure 3. Fracture effective permeability of coal to gas and water at different confining pressures - Sample 2

Figure 4. Fracture effective permeability of coal to gas and water at different confining pressures - Sample 3

Figure 5. Fracture effective permeability of coal to gas and water at different confining pressures: Sample 3 – 2.25 MPa

Figure 6. Fracture effective permeability of coal to gas and water at different confining pressures: Sample 3 – 4 MPa

Figure 7. X –ray CT scan images of sample 3at a particular location along the axial direction at different saturation states

Figure 8. Fracture effective permeability of coal to water as a function of effective stress and saturation – Sample 3

Figure 9. Fracture effective permeability of coal to gas as a function of effective stress and saturation – Sample 3

Figure 10. Fracture effective permeability of coal to water: surface representation – Sample 3

Figure 11. Fracture effective permeability of coal to gas: surface representation – Sample 3

Figure 12. Fracture effective permeability of coal to water as a function of ratio of flowrates – Sample 4, Confining pressure: 2.28 MPa

Figure 13. Fracture effective permeability of coal to gas as a function of ratio of flowrates – Sample 4, Confining pressure: 2.28 MPa

Figure 14. Fracture effective permeability of water as a function of ratio of flowrates – Sample 4, Confining pressure: 4.1 MPa

Figure 15. Fracture effective permeability of gas as a function of ratio of flowrates – Sample 4, Confining pressure: 4.1 MPa

Figure 16. Fracture effective permeability of coal to CO₂ as a function of effective stress – Sample 4, Confining pressure: 2.28 MPa

Figure 17. Fracture effective permeability of coal to CO₂ as a function of effective stress – Sample 4, Confining pressure: 4.1 MPa

Figure 18. Cumulative gas production: comparison between using single and multiple kr's with and without the effect of matrix shrinkage

Table 1a. Dimensions of coal samples used in the study

Sample #	Sample Dimensions	
	Diameter(inch)	Length(inch)
1	2	3.25
2	2	5
3	2	4
4	2	4

Table 1b. Petrographic Analysis of the samples- summary

Maceral	Sample #1		Sample #2		Sample #3	
	%, mmf	%, mmc	%, mmf	%, mmc	%, mmf	%, mmc
Vitrinite, V-types						
6	1	1	12.1	11.4	13.1	12.1
7	81.3	78.6	71.7	67.4	67.9	63
8	13.4	12.9	9.3	8.7	6.1	5.6
Total Vitrinite	95.7	92.5	93.1	87.5	87.1	80.7
Liptinite						
Sporinite	0.4	0.4	0.8	0.8	2.6	2.4
Resinite	0.2	0.2	0.1	0.1	0.1	0.1
Cutinite	1.2	1.2	1	0.9	1	0.9
Liptodetrinite	0.4	0.4	0.2	0.2	0.6	0.6
Total Liptinite	2.2	2.2	2.1	2	4.3	4
Inertinite						
Fusinite	0.5	0.5	0.8	0.8	2.4	2.2
Semifusinite	0.5	0.5	1.9	1.8	3.9	3.6
Macrinite	0.2	0.2	0.1	0.1	0.4	0.4
Micrinite	0.6	0.6	1	0.9	0.6	0.6
Inertodetrinite	0.3	0.3	1	0.9	1.3	1.2
Funginite						
Mineral Matter	-	3.2	-	6	-	7.3
Total Inertinite	2.1	5.3	4.8	10.5	8.6	15.3
Rmax, StD n=100	0.77 %, 0.03		0.74 %, 0.04		0.75 %, 0.04	

Table 1c. Proximate Analysis of samples - summary

	Sample #1		Sample #2		Sample #3	
	Dry	daf	Dry	daf	Dry	daf
% Volatile Matter	41.17	44.26	39.61	45.47	36.56	44.9
% Fixed Carbon	51.85	55.74	47.51	54.53	44.86	55.1
% Ash	6.98		12.88		18.58	
% Total Sulfur	2.53		4.48		2.2	

Table 2. Pressure and flow rate measurements- sample 1

q(cc/min)	P _{in} (MPa)	P _{out} (MPa)	P _{conf} (MPa)	
8	1.8	0.4	2.5	Trial 1
5	1.4	0.4	2.5	
1	0.7	0.4	2.5	
8	2.4	0.4	4.1	
5	1.8	0.4	4.1	
1	0.7	0.4	4.1	
8	3.5	0.4	6.7	
5	2.5	0.4	6.7	
1	0.9	0.4	6.7	
8	4.4	0.4	8.9	
5	3.1	0.4	8.9	
1	1.0	0.4	8.9	
6	2.5	0.5	2.6	Trial 2
4	2.1	0.5	2.6	
1	1.1	0.5	2.6	
6	3.3	0.5	4.0	
4	2.6	0.5	4.0	
1	1.1	0.5	4.0	
6	5.0	0.5	6.8	
4	3.8	0.5	6.8	
1	1.5	0.5	6.8	
2	2.4	0.4	2.6	Trial 3
1	1.9	0.4	2.6	
0.5	1.3	0.4	2.6	
2	3.3	0.4	4.0	
1	2.2	0.4	4.0	
0.5	1.5	0.4	4.0	
2	4.4	0.4	6.8	
1	2.9	0.4	6.8	
0.5	1.9	0.4	6.8	
2	2.4	0.4	2.6	Trial 4
1	1.9	0.4	2.6	
0.5	1.4	0.4	2.6	
2	3.3	0.4	4.0	
1	2.3	0.4	4.0	
0.5	1.6	0.4	4.0	
2	4.5	0.4	6.8	
1	2.9	0.4	6.8	
0.5	1.9	0.4	6.8	

Table 3. *Pressure and flow rate measurements- sample 2*

q_{gas} (cc/min)	q_{brine} (cc/min)	P_{in} (MPa)	P_{back} (MPa)	P_{conf} (MPa)
0.25	0.37	1.43	0.18	2.1
0.45	0.37	1.62	0.20	
0.45	0.15	1.28	0.21	
0.65	0.15	1.30	0.21	
0.85	0.05	0.88	0.21	
0.4	0.55	1.96	0.21	
0.1	0.55	2.00	0.17	
3	0	1.31	1.03	
0.2	0.3	2.30	0.18	3.8
0.5	0.3	2.65	0.20	
1	0.3	2.57	0.27	
2	0.3	2.83	0.53	
3	0.3	3.14	0.69	
0.5	0.5	3.31	0.48	
0.1	0.5	3.27	0.47	
0.1	0.7	3.58	0.48	
4	0.04	2.90	1.38	
3	0	1.17	0.69	

Table 4. Pressure and flow rate measurements- sample 3

q_{gas} (cc/min)	q_{brine} (cc/min)	P_{in} (MPa)	P_{back} (MPa)	P_{conf} (MPa)
2	3	1.10	0.59	2.25
3.75	3	1.19	0.70	
5	1	1.12	0.71	
5	0.25	0.99	0.71	
6	0.05	0.89	0.73	
7	0.05	0.94	0.77	
9	0.05	0.99	0.83	
6	0	1.03	0.96	
0.5	1.5	2.76	0.65	4
0.5	1	2.55	0.65	
1.5	0.35	2.86	1.01	
2.1	0.25	2.83	1.34	
3.5	0.25	2.87	1.55	
3.5	0.15	2.72	1.65	
3.5	0.05	2.62	1.67	
6	0	2.76	2.34	

Table 5. Pressure and flow rate measurements- sample 4: $P_{\text{conf}} = 2.28$ MPa

q_{gas} (cc/min)	q_{brine} (cc/min)	P_{in} (MPa)	P_{back} (MPa)	
0.17	0.5	1.08	0.48	He - brine
0.17	0.25	0.85	0.48	
2	1	1.59	0.50	
2.5	1.2	1.78	0.62	
3	1.45	2.11	0.83	
3	0.5	1.50	0.54	
4	0.1	1.03	0.52	
5	0.05	0.95	0.55	
6	0	0.81	0.63	
2	1	2.06	0.34	CO ₂ - brine
2	0.96	2.14	0.38	
3	0.5	1.80	0.50	
4	0.1	1.35	0.62	
5	0.05	1.20	0.63	
0.17	0.25	1.06	0.34	
0.17	0.5	1.48	0.34	
6	0	1.83	1.52	

Table 6. Pressure and flow rate measurements- sample 4: Pconf = 4.1 MPa

q_{gas} (cc/min)	q_{brine} (cc/min)	P_{in} (MPa)	P_{back} (MPa)	
0.33	1	1.76	0.35	He - brine
2.4	1.05	3.35	0.97	
2	1	3.41	0.97	
3	1	3.42	0.97	
3	0.5	2.85	0.90	
4	0.1	2.03	0.89	
5	0.05	1.83	1.02	
6	0	1.65	1.24	
0.17	0.5	1.74	0.41	CO ₂ - brine
1.14	0.5	2.65	0.48	
1.52	0.5	3.09	0.69	
3	0.5	3.73	0.93	
4	0.1	2.85	1.38	
5	0.05	2.62	1.38	
6	0	2.00	1.38	

Table 7. Reservoir, rock and fluid properties and initial conditions

Reservoir dimensions (m)	Grid blocks in x, y and z directions	Reservoir thickness (m)	Fracture porosity, Matrix porosity (%)
830 × 457	12×8×1	3	1, 8
Fracture permeability(mD), Matrix permeability (mD)	Fracture spacing (m)	Reservoir temperature (C)	Reservoir Depth (m)
8,0.001	0.3	27	305
Initial reservoir pressure (MPa)	Coal density (g/cc)	Initial water saturation (fracture) %	Initial water saturation (matrix) %
3.4	1.435	100	5
Langmuir pressure constant (1/MPa)	Langmuir volume (scf/ton)	Desorption time (days)	Sandface pressure (MPa)
0.86524	480	100	0.1
Young's Modulus(psi)	Poisson's ratio	Strain at Infinite pressure	Palmer and Mansoori Exponent
436000	0.4	0.03	3

Table 8. Description of various scenarios used

Scenario No	Description
1	Modeled using X curves
2	Modeled using multiple relative permeability curves
3	Modeled using X curves and accounting for coal matrix shrinkage
4	Modeled using multiple relative permeability curves accounting for coal matrix shrinkage

Table 9. Relative permeability – Experimentally determined: (1.4 – 1.7 MPa)

S_w	k_{rw}	k_{rg}
0	0	0.11
0.86	0.04	0.11
0.9	0.2	0.03
0.94	0.9	0.01
1	0.9	0

Table 10. Relative permeability – Experimentally determined: (1.7 – 2 MPa)

S_w	k_{rw}	k_{rg}
0	0	0.02
0.88	0.01	0.02
0.9	0.02	0.009
0.92	0.03	0.008
1	0.03	0