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Relative Permeability of Coal: A Review

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Abstract Coalbed methane (CBM), once a hazard to the undermining safety, is becoming an important addition to the global energy supply. Injecting carbon dioxide (CO_2) into coal seams not only aids to enhance CBM production but also offers an option of CO_2 sequestration helpful for the reduction of greenhouse gas release. Multiphase flow occurs in those cases as most coalbeds are initially saturated with water. Accurate determination of relative permeability of coal plays an important role in the prediction and evaluation of those operations because it is in effect the effective permeability (absolute permeability multiplied by relative permeability) to gas/water rather than absolute permeability that controls the flow in coal seams. To date, varying methods have been reported of obtaining relative permeability curves of coals through either laboratory tests or field data analysis, which are reviewed in this paper. Also, this paper includes a summary of the characteristics of relative permeability curves of coals, relative permeability models, effects of varying factors on curves and effects of the curves on CBM production. This paper concludes that despite the importance of relative permeability in CBM-related operation process, limited research efforts have been paid on improvements concerning this subject in the past two decades: the advance in the research of relative permeability-related subjects can barely keep up with the rate at which the developments of CBM and CO_2-ECBM projects are booming worldwide. More efforts are needed to conduct related investigations such that a reliable standard or workflow can be established that can as accurately determine coal relative permeability with repeatability.

Keywords Coal · Relative permeability · Measurement methods · Model · Influencing factors

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1 Introduction

Coalbed methane (CBM), together with tight gas and shale gas, makes up the world's major unconventional gas resources. The remaining technically recoverable CBM is estimated to 193 trillion cubic meters (Tcm) at the global level (McGlade et al. 2013). The utilization of CBM can not only add to the world's gas supply but also help to enhance underground safety for mining workers and contribute to greenhouse gas reduction (Karacan et al. 2011). To date, the development of CBM at commercial scale has been carried out mainly in the United States, Canada, Australia, and China (McGlade et al. 2013; Moore 2012).

Commonly, coal is considered as a dual porosity system that contains micropores (matrix) and macropores (cleats). CBM is mainly stored within the matrix by physical adsorption (e.g., Harpalani and Chen 1997). In wet CBM reservoirs, the cleats are usually initially saturated with water. During the primary recovery of CBM, water must be drained prior to gas production so that the reservoir pressure can be lowered and subsequent gas desorption from internal matrix surfaces can be initiated. Once desorbed gas enters the cleats (through diffusion) and achieves irreducible gas saturation, simultaneous gas and water flow occurs in the cleats.

As primary recovery of CBM may need a relatively long period of water drainage and has a low recovery factor, injecting nitrogen, CO_2 or their binary mix into coalbeds has been applied to enhance CBM production and ultimate recovery. Because coals tend to adsorb both nitrogen and CO_2, the presence of those gas species in coalbeds can bring about a competitive sorption effect and alter the sorption of the methane in coal matrix. The injection of CO_2 not only enhances CBM production but also helps reduce the release of this greenhouse gas. Nowadays, CO_2 enhanced coalbed methane (CO_2-ECBM) has become a research hot spot in both in-house experiments and simulations (e.g., Fujioka et al. 2010; Pini et al. 2009; Shi and Durucan 2005; Sınayuç and Gümrah 2009; Zarrouk and Moore 2009; Zhou et al. 2013) and field pilots and tests (e.g., Fujioka et al. 2010; Pan et al. 2013; Pagnier et al. 2005; Wong et al. 2007).

Multiphase flow occurs at reservoir conditions for both primary and enhanced coalbed methane recovery processes. The effective permeabilities to water and gas dominate the ratio of fluid flows rather than the absolute permeability. Relative permeability, the ratio of the effective permeability to the absolute permeability of the porous media, is commonly used for characterizing the flow capacity for one fluid during a simultaneous filtration of multiphase systems in petroleum industry. Relative permeability, together with other reservoir properties like coal seam pressure, permeability, gas content, and water saturation, controls the effective CBM reservoir flow capacity (Clarkson et al. 2011; Karacan et al. 2008; Karacan 2013a, b). The relative permeability not only determines whether commercial gas production rates can be achieved but also affects the cost of produced water disposal by controlling the amount of drained water (Ham and Kantzas 2011). A sound and thorough knowledge on the relative permeability characteristics is crucial for optimal design of CO_2 injection strategies in CO_2-ECBM because permeability to CO_2 (especially in near-well zone) exerts profound effect on the CO_2 injectivity (Deng et al. 2012; Kumar et al. 2012).

2 Methods to Obtain Relative Permeability of Coal

Numerous methods have been proposed to derive relative permeability curves of coals, including unsteady-state, steady-state, capillary pressure, numerical inversion, history matching, and production data analysis methods. The first four methods are based on interpretation of laboratory experiment data, whereas the last two methods use field data as input. While coals differ from conventional sand rocks because of distinguishing features such as low permeability, highly developed natural fractures and sorption to gases (such as methane and CO_2), very few modifications have been made in the first three methods (steady-state, unsteady-state, and capillary pressure methods) when translating from conventional to unconventional cases.

2.1 Sample Preparation for Laboratory Experiment Methods

Laboratory experiments directly obtain the relative permeability of coal by conducting core-related tests. Coal core is required in these in-house tests. It is common practice to obtain a coal core by drilling raw coal chunks with a core bit. This method can preserve much of the natural fracture geometry that can influence fluid flow through the porous coals. Metcalfe et al. (1991) recommended the use of whole core samples containing several cleats since it is the porosity and relative permeability of the cleat system that is desired. They also suggested that core selected for relative permeability testing should be done in water-filled troughs and the selected material should be bagged with free water included. Puri et al. (1991) found that it is best to use whole diameter (2.5–3.5 in.) core samples because smaller core plugs may not contain adequate cleating. They also suggested that the core for tests have a length/diameter ratio of at least 1 whereas the ratio suggested by Hyman et al. (1992) is 0.75. As coal is relatively fragile and prone to damage during the coring operation, some authors (e.g.,) also used the coal core manufactured from coal powder with high pressure press. However, this method is not preferred for relative permeability measurement because the inherent cleat structure is destroyed once raw coal is smashed. Such cores were found to have a greater permeability and porosity values than actual coal matrix, and thus are incapable of reproducing the actual flow behavior at *in situ* conditions.

2.2 Unsteady-State Method

In this method, the coal core is first saturated with a wetting phase fluid and then the non-wetting phase fluid is continuously injected to displace the pre-existing phase at constant flow rate or pressure (Fig. 1a). Flow rate and pressure difference are recorded throughout the measurement. Relative permeabilities have been derived from the displacement experimental data using one of five methods: the Welge (1952), JBN Johnson et al. (1959), Jones-Roszelle Jones and Roszelle (1978), Hagoort Hagoort (1980), and Ramakrishnan-Cappiello Ramakrishnan and Cappiello (1991) methods, among which JBN is the most commonly used. Christiansen et al. (1997) provides a summary, an example of the calculations, and a theoretical justification for each of the five methods.

Usually, coal is assumed to be water-wet at low pressures (Mazumder et al. 2003) and therefore the displacing and displaced fluids are usually gas and water, respectively. This assumption, though frequently used, remains problematic. Gash (1991) showed that coal could be methane-, water-, or mixed-wet depending on the degree of mineralization. illustrated that for a coal-water system, a maximum contact angle occurs at a pH value of around 7, indicating an alteration of coal wettability with increasing pH. Ham and Kantzas (2011) stated that coal may be initially water-wet at high water saturation and turns to gas-wet due to gas injection and subsequent adsorption. Plug et al. (2008) tests on capillary pressure in a CO_2–water–coal system showed that semianthracite coal exhibits a water-wet behavior in primary drainage and turns to CO_2-wet during primary imbibition. More recently, Sakurovs and Lavrencic (2011) found that contact angles in the coal–water–CO_2 system exhibit a declin-

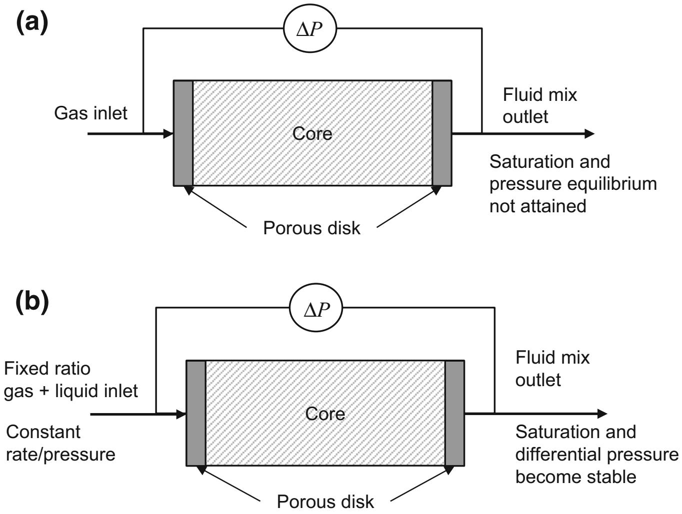


Fig. 1 Schematic setups for **a** unsteady-state method and **b** steady-state method

ing trend with increasing pressure for five Australian coals. They also observed that one coal having low rank and high ash yield never became CO_2-wet even at pressure up to 15 MPa. These observations indicate that the wettability of coal surface exhibits complex behaviors and displacing water with gas or gas with water can lead to differing results (which will be discussed in detail in Sect. 5.5).

One of the most distinguishing advantages of the unsteady-state over the steady-state method is that the former takes a markedly shorter time. However, accurately recording volumes of produced fluids at appropriate time periods throughout the test is a challenge, because manual techniques are typically employed to record fluid production data (Maloney and Doggett 1995). Another disadvantage of the unsteady-state method, as stated by Nourbakhsh (2012), is that further reduction of water saturation is extremely difficult, if the core sample has low permeability to water, resulting in reduced gas permeability of the sample. Additionally, the models invoked for obtaining relative permeabilities assume an isotropic and homogeneous nature for the porous media, which can hardly be satisfied in coals.

2.3 Steady-State Method

When applying this method, gas and water are simultaneously injected into the core at constant rate until the pressure gradient along the core axis becomes stable and equilibrium state is achieved (Nourbakhsh 2012) (Fig. 1b). By changing the ratio of injection rates and repeating the measurements as equilibrium is attained, the curves of relative permeability versus saturation are obtained (Honarpour and Mahmood 1988). At each rate, the saturation is determined by one of the following independent techniques: (i) gravimetric or volumetric material balance, (ii) X-ray or gamma scanning or (iii) CT scanning (Karimi 2005). The effective permeabilities to gas and water can be calculated following the Darcy's law.

The steady-state method has more accurate and reliable results compared to the unsteady-state method (Honarpour and Mahmood 1988). It also accommodates a broader range of saturations than the unsteady-state method and does not require an independent determination of porosity (Hyman et al. 1992). As Ali (1997) suggested, this method is preferred for reservoirs with more core-scale heterogeneity and with mixed wettability (which may frequently be encountered in coals). However, one of the major disadvantages is that this method requires a relatively long time to reach equilibrium state, especially for low-permeability rocks, and the cost is higher. Besides, capillary forces and capillary end effects are significant (Kamath et al. 1993).

2.4 Capillary Pressure Method

The measurement of capillary pressure curve of a coal sample is much simpler than core flooding tests. Four methods have been used for determining a capillary pressure curve: the (i) mercury injection, (ii) restored-state (also referred to as porous diaphragm), (iii) centrifugal, and (iv) vapor desorption methods (Newsham et al. 2004). The first laboratory measurement of capillary pressure curves in coals was by Dabbous et al. (1976), followed by Jones et al. (1985). Since then, very few investigations were undertaken concerning this topic until Plug et al. (2008), followed by two more recent papers by Ham (2011) and Nourbakhsh (2012). Mercury injection was used by Jones et al. (1985) and Ham (2011). Dabbous et al. (1976), Plug et al. (2008), and Nourbakhsh (2012) used the restored-state method, which is suggested to be the most suitable for coal because whole core samples can be tested and the problems associated with fines migration can be controlled more easily (Hyman et al. 1991; Ohen et al. 1991).

One important application of capillary pressure data is their use in the calculation of relative permeability (Dabbous et al. 1976). A number of mathematical models have been proposed for calculating two-phase relative permeabilities from capillary pressure data in porous media, among which the Purcell model (1949) and Brooks and Corey (1966) are most popular and have seen application in coals. It is noted that both Purcell models and Brooks-Corey models were derived on a basic assumption of a bundle of capillary tubes with various radii in the porous media (Fig. 2a). This assumption may hold true for conventional sand rocks. But for coals, which are typically inherently dual-porosity porous media, a matchstick model (Fig. 2b) may better describe its pore structure. Therefore, further work may be needed to modify the Purcell equations to better model relative permeabilities of coals (Chen et al. 2013).

2.5 Numerical Inversion Method

Numerical interpretation of laboratory core flooding data provides an alternative to analytical interpretation method (e.g., using JBN method). The numerical inversion methods endeavor to invert laboratory experiment data in order to interpret relative permeability in an implicit fashion. One distinguishing advantage of these methods is that both capillary effects and core-sample heterogeneity can be accounted for (Hou et al. 2012). The basic methodology for deriving relative permeabilities using a numerical inversion method can be summarized as follows (Hou et al. 2012): (1) select an objective function; (2) determine a relative permeability representation model; and (3) adjust controlling parameters of the representation model until a preset convergence condition is reached. Generally, an optimization algorithm integrated with a reservoir simulator is required to realize step 3. Consequently, relative permeability curves can be estimated implicitly.

Although many numerical inversion approaches have been proposed, only the Ohen method (Ohen et al. 1991) and Schembre-Kovscek method (Schembre and Kovscek 2006) have been applied in deriving relative permeabilities of coals. A major difference in these two methods is that relative permeabilities are represented by B-spline curves in Schembre-

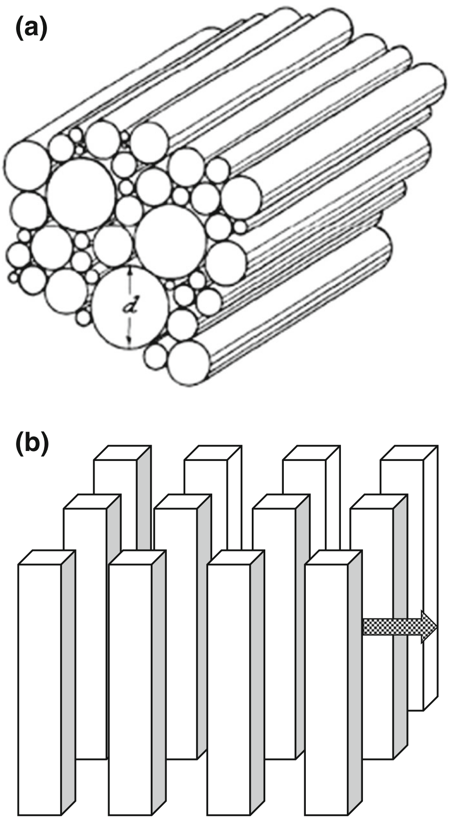


Fig. 2 Schematic illustration of bundle of capillary tubes model (**a**)(after Gates and Leitz 1950) and matchstick model (**b**) (after Seidle et al. 1992)

Kovscek method, whereas the capillary pressure is directly adjusted in the Ohen method and relative permeabilities are calculated from capillary pressure applying the Brooks and Corey model.

2.6 History Matching Method

In petroleum and CBM industry, history matching is a technique that endeavors to match simulated with field results by adjusting various input parameters within a reasonable range. On the premise of knowledge of majority of principle parameters (to which the output is sensitive), relative permeability curves can be obtained by adjustment until an acceptable error between the simulated and field results is achieved.

The use of a numerical simulator to conduct history matching of production data (e.g., gas rate, water rate, and bottomhole pressure) is a common practice to evaluate field-scale properties and predict the producibility of a CBM reservoir. A numerical reservoir model is first constructed that employs a series of reservoir property parameters prior to conducting a history match. Reservoir properties that are necessary for reservoir simulations include, e.g., formation depth, effective thickness, fracture spacing, initial gas content, *in situ* pressure, sorption parameters (Langmuir volume and Langmuir pressure), diffusion coefficient (or sorption time), temperature, absolute permeability, porosity, water saturation, and relative permeability curves. Additionally, well completion (e.g., skin factor, well radius, well trajectory, etc.) and historical production data should also be included in the model. Sensitivity analysis (Zhou 2012) shows that Langmuir volume, coal bulk density, water formation volume factor, vertical and horizontal permeability, water density, and porosity have strong influence on the gas rate whereas water formation volume factor, water viscosity, horizontal permeability, water density, and porosity have strong influence on the water rate.

Ideally, if all the other inputs except for relative permeability are reliable and within the acceptable range of error, we can adjust the relative permeability curves until a good match between the simulated and historical outputs is achieved. If so, the resultant relative permeability curves can be representative of the target formation.

This method is of practical significance when laboratory data is unavailable, and provides a point of comparison if laboratory data is available (Meaney and Paterson 1996; Young 1992; Young et al. 1991a, b). Young et al. (1991a, b) consider the use of history matching to be a reasonable method to develop a relative permeability relationship for gas and water. Aminian et al. (2004) state that history matching is "the only practical method to obtain realistic relative permeability values" because great uncertainty occurs when upscaling laboratory results to reservoir conditions (Müller 2011). Even if a relative permeability relationship is measured in a core, these measurements are often not representative of the behavior exhibited by gas and water production from a well (Young et al. 1991a, b). However, it is noted that the accuracy of the history matching method to obtain relative permeability should be carefully examined due to the uncertainties in determining other related input parameters that exert effects on the output results. Besides, this method only covers a range of saturation up to current conditions (Al-Khalifah et al. 1987). Nevertheless, history matching is to date the primary way to provide the investigators with an insight into the relative permeabilities at *in situ* conditions.

2.7 Production Data Analysis Method

The technique of determining relative permeabilties from production performance data was first proposed by Fetkovich et al. (1986) for an oil-gas reservoir and then modified and applied into the estimation of methane-water relative permeability curves in CBM reservoirs e.g., Clarkson et al. (2007, 2009, 2011). The basic idea behind this methodology is to estimate the effective permeabilities to gas and water using Darcy's law, production rates, and measured (or estimated) flowing and shut-in pressures (Clarkson et al. 2007). The procedure for this method is presented in detail in Clarkson et al. (2011).

3 Summary of Relative Permeability Curves

A total of 81 sets of graphical relative permeability curves were acquired from publicly available literature. Appendix A lists a summary of some key information on these curves, including endpoint saturations, cross point saturation, and maximum relative permeability to gas/water. These curves were classified in accordance with the methods reviewed in Sect. 2.

3.1 Frequency of the Usage of Different Methods

Figure 3 depicts the comparison of frequency of usage of the six methods discussed in Sect. 2 using the dataset in Appendix A. Clearly, we can see that the most frequently used method is the unsteady-state method, with a total of 51 sets (58 %). It is followed by the history

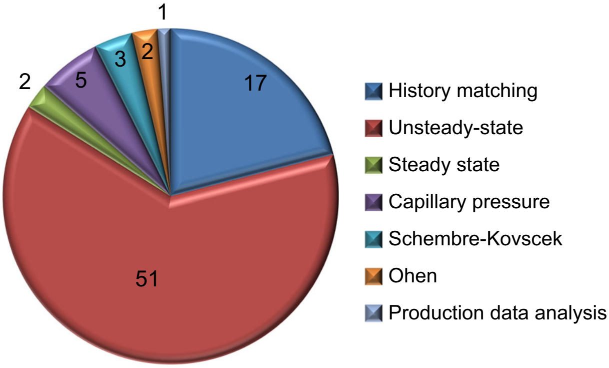


Fig. 3 Frequency of usage of various methods

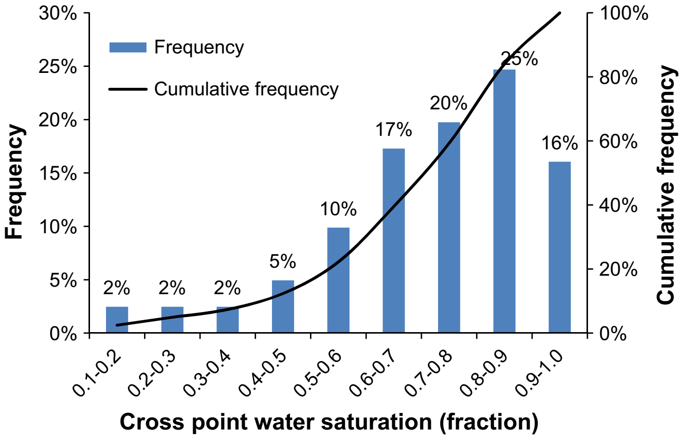


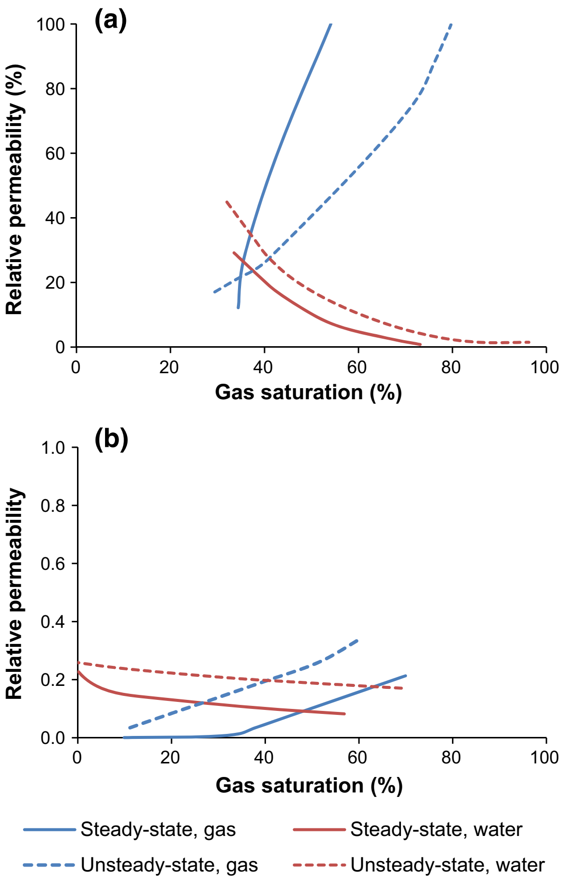
Fig. 4 Frequency distribution of cross point water saturation span obtained with various methods

matching method, used in 17 sets (19.3 %). The other five methods were used in only 22.7 % of all 81 data sets.

3.2 Cross Point and Endpoint Saturations

Cross point saturation is the saturation at which the relative permeability to gas equals that to water. The frequency distribution diagram is plotted in Fig. 4 of cross point water saturation obtained from the previous methods is plotted in Fig. 4. Despite of the varying experimental conditions (gas species, confining pressure, pH, etc.), most of the counted curves (89 %) have a cross point water saturation span larger than 0.5, which may indicate a water wettability nature of most coals. The water wettability nature is further confirmed if we refer to the wettability determination criteria for water–oil–sandstone system. In that criteria, rocks with irreducible water saturation higher than 0.2 (Li and Zhang 2006) are considered to be water-wet. According to our statistics data (Appendix A), 98 % of the curves have irreducible water saturation higher than 0.2. However, we note that conflicts may occur in judging the wettability if we solely rely on the cross point or irreducible saturation on relative permeability curves. For example, in one of the curves in Gash (1991), the cross point and irreducible water

Fig. 5 Comparison of steady- and unsteady-state methods. (**a**) after Gash (1991), (**b**) modified from Reznik et al. (1974) by dividing the effective permeabilities by an absolute permeability of 9 mD



saturations are 0.27 and 0.65 (Fig. 5a), respectively, which in turn imply opposite wettabilities according to the above discussion. Again, as stated in section 2.2, the coal wettability remains a quite complex and unclear issue, and further investigations are anticipated.

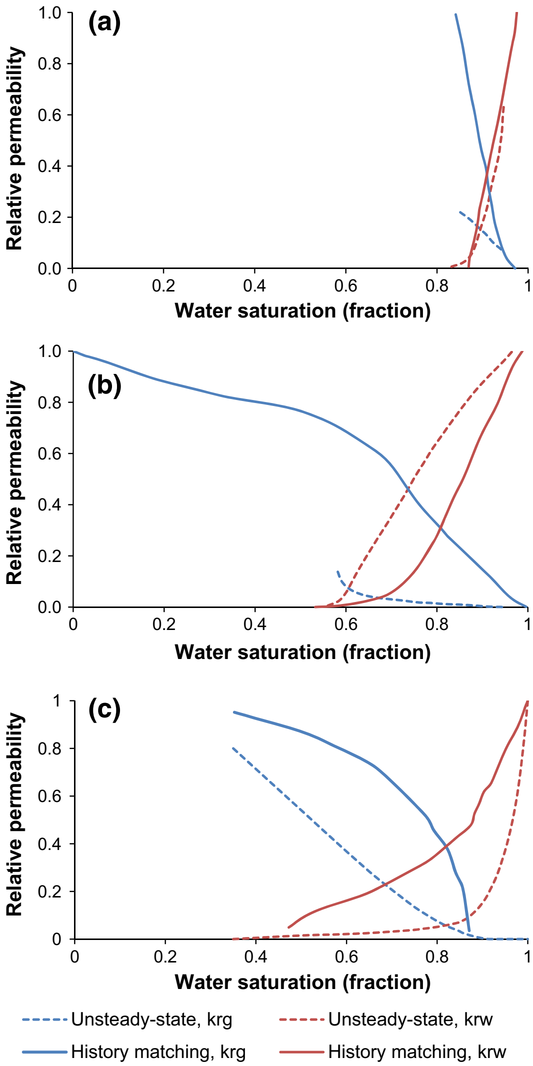
3.3 Comparison of the Curves Obtained Through Unsteady- and Steady-State Methods

To date, very limited investigations have been conducted comparing of unsteady- and steady-state methods. Figure 5 exhibits the results of two typical studies (Gash 1991; Reznik et al. 1974) of this kind. As shown, the curves obtained from unsteady- and steady-state methods exhibit general similarities but distinct differences. Gash (1991) suggests that the apparent "displacement" of the curves is due to sodium iodide adsorption in the steady-state method. We suggest that such displacement may also stem from the inherent drawbacks of the interpretation procedure used in the unsteady-state method.

3.4 Comparison of the Curves Obtained Through History Matching and Laboratory Measurement

Among the history match practices (Appendix B) in which relative permeability curves were derived, Meaney and Paterson (1996) and Conway et al. (1995) compared the derived curves

Fig. 6 Comparison of history matching and unsteady-state methods. **a** and **b** are after Meaney and Paterson (1996) while **c** is after Conway et al. (1995)



with those obtained through laboratory measurement. Differences in the curves obtained by history matching and by laboratory tests have been observed by other workers (e.g., Ramurthy et al. 2003), which are not presented here because the coal sample used for in-house experiments was not exactly from the field where the well(s) chosen for history matching was (were) located. Since strong heterogeneity occurs in a CBM reservoir, samples and histories from different well(s) site may bring in unexpected errors, making the curves poorly comparable.

Figure 6a depicts the relative permeabilities of a coal from northern Sydney Basin, where the history matched and laboratory measured curves are from Meaney and Paterson (1996). The coal used for unsteady-state test and history matching were from the same borehole. The relative permeabilities to water obtained with the two methods show general similarity, but large deflection is observed in relative permeabilities to gas. Cross point and endpoint water saturations show respective similarity for the two methods. Figure 6b shows another comparison of the relative permeabilities obtained of German Creek seam in Bowen basin with two methods. Clearly, unlike the Sydney basin case, large deflections are encountered in the curves by varying methods. This may be due to the heterogeneity in sample to sample variation (Meaney and Paterson 1996).

Apart from the relative permeability curves obtained by unsteady-state method, Conway et al. (1995) reported a set of "field trial" curves constructed by history matching production and shut-in well testing data in Blue Creek seam. It shows that the relative permeability to gas obtained by history matching is higher than that from unsteady-state measurement, which also holds true for the water phase (Fig. 6c). However, it is noted that the derived curves from history matching result in inaccurate estimations of reservoir parameters when applied to other well tests (Conway et al. 1995). On the one hand, these findings reflect the strong heterogeneity of coal, and on the other hand confirm that it is not reliable to depend on only one method to obtain the relative permeability of coal.

4 Relative Permeability Models for Coal

4.1 Brooks-Corey

The relative permeability model developed by Brooks and Corey (1966) is the most widely used model for multiphase relative permeability in porous media. Although the model was originally derived for the case of two-phase flow of oil and gas through conventional sedimentary sand rocks, it is found to be capable of modeling gas and water relative permeability curves in coals with high accuracy (Shen et al. 2011; Clarkson et al. 2011). The Brooks-Corey model is expressed as:

$$k_{rw} = \left(S_w^*\right)^{\frac{2+3\lambda}{\lambda}} \tag{1}$$

$$k_{rnw} = \left(1 - S_w^*\right)^2 \left[1 - \left(S_w^*\right)^{\frac{2+\lambda}{\lambda}}\right], \tag{2}$$

where λ is pore size distribution index and S_w^* is the normalized wetting phase saturation, defined as

$$S_w^* = \frac{S_w - S_{wr}}{1 - S_{wr} - S_{nwr}}, \tag{3}$$

where S_{wr} and S_{nwr} are the irreducible saturations of wetting and non-wetting phases, respectively.

4.2 Chen et al.

Recently, Chen et al. (2013) developed a relative permeability model specific for coals. This model, to the knowledge of the authors, is so far the only one that is specifically constructed for modeling gas (methane) and water relative permeabilities in coals. Two important phenomena associated with methane transport within coal have been considered: (1) a matchstick geometry (Fig. 2b) that accounts for dual porosity instead of the widely used bundle of capillary tubes model; and (2) matrix shrinkage effects that result in a change in porosity and permeability. This relative permeability model, different from a majority of previous models before it, is dependent on both saturation and porosity. The derivation of the models is similar to that of Brooks-Corey models and contains a concrete theoretical basis. The three principle models in the derivation that distinguish Chen et al.'s model from Brooks-Corey's model are: Capillary pressure equation, Poiseuille's equation and permeability model. The resulting relative permeabilities to gas and water are given as

$$k_{rw} = k_{rw}^{*}(S_w^{*})^{\eta+1+2/(J\cdot\lambda)} \tag{4}$$

$$k_{rnw} = k_{rnw}^{*}(1-S_w^{*})^{\eta}\left[1-\left(S_w^{*}\right)^{1+2/(J\cdot\lambda)}\right], \tag{5}$$

where λ is the cleat size distribution index; J is a shape factor that is introduced to account for the change of λ with porosity; $k_{rw}^{*}$is the end-point relative permeability of the wetting phase; k_{rnw}^{*} is the end-point relative permeability of the non-wetting phase; S_w^{*} is defined as

$$S_w^{*} = \frac{S_w - S_{wr0}e^{n_{wr}c_f(\sigma-\sigma_0)}}{1-S_{wr0}e^{n_{wr}c_f(\sigma-\sigma_0)} - S_{gr0}e^{n_{gr}c_f(\sigma-\sigma_0)}\left(\frac{\rho_g}{\rho_{g0}}\right)^{-1}}, \tag{6}$$

where ρ_g is the density of gas; σ is the effective horizontal stress; the subscript "0" represents an initial state; c_f is the compressibility of coal cleat; n_{wr} and n_{gr} are fitting parameters to determine the relationship between the residual phase saturation and the porosity ratio.

It is noted that Chen et al. (2013) include an implicit assumption that water is the wetting phase while gas is the non-wetting phase. This assumption, as stated in previous section, remains problematic and needs further investigation. Nevertheless, the Chen et al. (2013) model shows a strong capability to match the experimental data for different coal relative permeability measurements. Later, Chen et al. (2014) fitted eleven sets of relative permeability curves of European and Chinese coals with their model (Eq. 4 through 6) and found that the cleat size distribution index (λ) has a U-shape correlation with both vitrinite reflectance and fixed carbon. Their work implies the influence of coal rank on its relative permeability but more work is warranted to validate this U-shape trend for other coals (Chen et al. 2014).

4.3 Shen et al.

Pore structure is well recognized to exert a significant influence on relative permeability characteristics for porous media (Jerauld and Salter 1990; Burdine 1953) including coals (Ahmed et al. 1991; Chen et al. 2013; Nourbakhsh 2012). Coals with higher rank or/and higher vitrinite content have more micropores whereas meso- and macropores are more developed in lower rank and/or inertinite-rich coals (Clarkson and Bustin 1996; Crosdale et al. 1998). Other workers (e.g., Rodrigues and Sousa 2002; Sakurovs et al. 2012; Zhang et al. 2010; Hall et al. 2000) suggest a dependence of pore structure/distribution on coal rank and composition. Additionally, a dependence of permeability increase/decrease on coal rank, vitrinite content, and ash content has been observed by Wang (2007). Because the pore structure or/and pore size distribution exhibits a close correlation with coal rank and maceral content (e.g., Rodrigues and Sousa 2002; Sakurovs et al. 2012; Zhang et al. 2010; Hall et al. 2000), and also because the composition of a coal influences the wettability, which in turn affects the relative permeability, it is reasonable to develop a relationship between the relative permeability and coal rank and macerals.

Shen et al. (2011) proposed an empirical model for predicting relative permeability to water and gas in coals, applying multiple regression analysis on experimental data from five coals with different ranks. The empirical expressions are as follows:

$$k_{rg} = \left(-0.29R_{o,\max} + 0.0073V - 0.0031I + 0.097A\right) S_{ng}^{9.5R_{o,\max}-0.11V+0.48I-5.64A} \tag{7}$$

$$k_{rw} = \left(0.02R_{o,\max} + 0.0018V + 0.0069I - 0.06A\right) S_{ng}^{403.36R_{o,\max}-13.96V+2.59I+104.41A} \tag{8}$$

where $R_{o,max}$, V, I, and A denote the maximum vitrinite reflectance, vitrinite, inertinite, and ash content, respectively; S_{ng} is the normalized gas saturation.

The biggest advantage of using the empirical model is that it replaces the laborious and difficult work of determining relative permeability with simpler measurement of coal composition. However, it is noted that the coefficients in Eqs. 7 and 8 were obtained on a basis of limited experimental data and thus its universality remains questionable. Further work is required to evaluate its validity if more experiment data is available.

5 Effects of Factors on Relative Permeability of Coal

The effects of several factors on relative permeability of coal have been studied in several previous papers and are pulled together in this paper. Since the important effects of coal rank and composition have been discussed in Sect. 4.2 and 4.3, this section will mainly address the effects of several other factors.

5.1 Overburden Stress

The effects of overburden stress on the absolute permeability of coals have been thoroughly and widely investigated (see e.g., Pini et al. 2009; Huy et al. 2010; Pan et al. 2010a; Pan and Luke D 2012). However, very limited research has been conducted of its effect on relative permeabilities. One typical paper concerning this subject is Reznik et al. (1974), who observed different response of gas relative permeability to confining pressures (Fig. 7). Reznik et al. (1974) attributed the varying response to the inaccurate recording of water saturation during experiments. However, as indicated in Dabbous et al. (1974), the cause may partly be due to the variation in the mechanics parameters in the coal samples: friable coals are more sensitive to stress change, resulting in more severe evolvement of pore size and hence absolute permeability. The study by Gash et al. (1992) demonstrated that in all directions the relative permeability ratio k_{rg}/k_{rw} increases with the increase of confining pressure. This indicates that increasing confining pressure decreases the flow of gas (relative permeability to gas) less than it does flow of water (Gash et al. 1992). One possible explanation for this phenomenon may be due to the Klinkenberg (slippage) effect, which can increase the apparent gas permeability by orders of magnitude in low-permeability media. As the overburden stress increases, the cleat aperture becomes narrower, resulting in a more significant Klinkenberg effect on gas permeability. The enhancement in Klinkenberg effect can partly offset the reduction in gas permeability caused by stress compression. More recently, Durucan et al. (2013) observed that the increase in confining pressure causes a small but noticeable shift in the curves towards lower relative permeabilities for both gas and water. Also, the gas saturation and relative permeability at cross point are both lowered at higher confining pressure. The interpreted irreducible water saturation, as noted by Durucan et al. (2013), is in particular higher due to the entrapment of water pockets. As a summary, the results of previous studies have so far been inconclusive. Also, the reasons for the varying effects of overburden pressure on the relative permeability curves have not yet been clearly revealed, and further work is warranted.

5.2 Cleat Orientation

As is known, two types of cleat (butt and face cleats) occur in coal. The face cleat is the dominant fracture system and the butt cleat is less laterally continuous and almost always terminates where it intersects a face cleat (Moore 2012). The ratio of absolute permeability along face cleats relative to butt cleats is typically on the order of 4:1 (Clarkson and Bustin 2011) and can be as high as 17:1 (Koenig and Stubbs 1986). Though large variations occur in the absolute permeability regarding orientation, it is quite surprising that the relative permeability data in both the face and butt cleat directions are identical within experimental accuracy (Jones et al. 1985) and there is no obvious effect of cleat orientation on gas-water relative permeability (Gash et al. 1992).

5.3 Cleat Network Geometry

Previous studies (Burdine 1953; Bustos and Toledo Pedro 2003; Morris and Pyrak-Nolt 1999; Jerauld and Salter 1990) have shown that pore size distribution or fracture network geometry can affect the relative permeability curves in porous media. By analogy, it is reasonable to assume that the fracture network geometry within a coal should exert some influence on the relative permeabilities. This has been proven by Morris et al. (1999) and more recently, by Chen et al. (2013). Morris et al.'s (1999) explored the effect of both pore size and spatial distribution using network flow modeling. Their results show that uncorrelated fractures have lower non-wetting saturations at cross-over than correlated fractures. Chen et al. (2013) derived from sensitivity analysis based on their model (Eq. 4 through 6) that 1) the water relative permeability increases whereas the gas relative permeability decreases with the increment of the cleat size distribution index; and 2) with the increase of η, the coal cleats become more tortuous and the consequent relative permeability for both water and gas phase decreases.

5.4 Testing Fluids

5.4.1 Gas Species

Relative permeability curves measured with different gas species are found to exhibit varying shapes (Ham and Kantzas 2011). Nourbakhsh's (2012) experiments showed that methane/brine has both higher relative permeability and higher irreducible water saturation than the CO_2/brine system. It is also observed that the curve for methane/brine is less concave. These differences might partly be due to the changes in coal wettability and the coal structure in response to applied pressure of gas injection (Ham and Kantzas 2011). One important reaction between coals and fluids is the mineral dissolution by gases, especially CO_2. Clay minerals in particular are very susceptible to changes in the surface layer chemistry, which affects the wettability and consequently the relative permeability (Busch et al. 2008 cited by Müller 2011). It is observed that the presence of CO_2 in coal can dissolve minerals and increase the volumes of pores in anthracite coals (Liu et al. 2010). Once the pore structure of coal is rearranged, capillary pressure and hence relative permeabilities have the potential to change (Burdine 1953). We also note that it is reasonable to invoke the sorption-induced strain for explaining the differences in relative permeabilities using different gas species, though so far no efforts have ever been taken to quantitatively experiment on the effects of coal structure changes caused by gas sorption on relative permeabilities.

5.4.2 Liquid pH

It is observed that pH values of the brine have an effect on the cross point saturation of air-brine relative permeability curves in River Basin coals. The cross point has a highest value of water saturation for pH 10 and least for pH 7, which suggests that the coal–water–

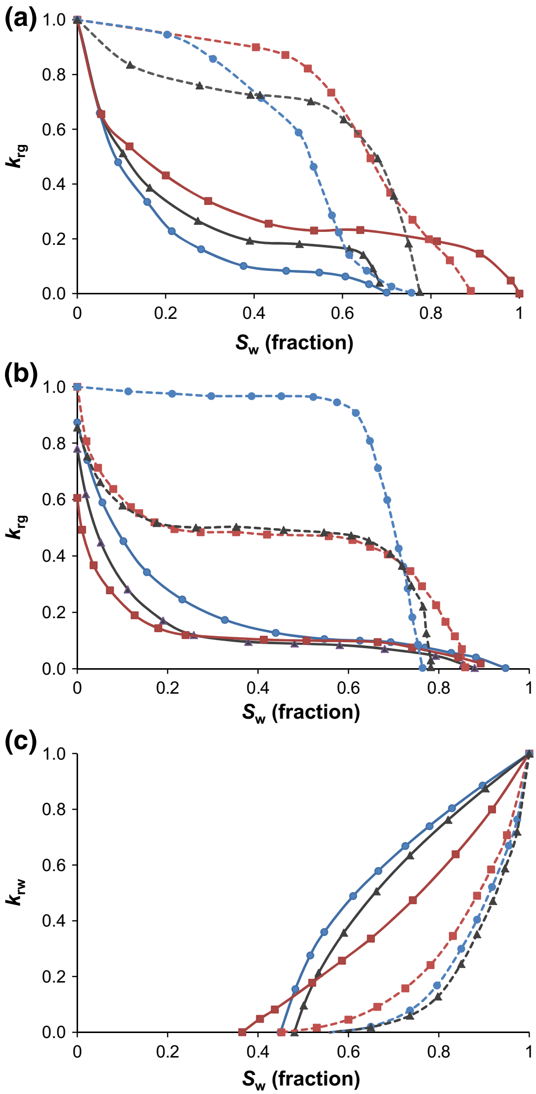


Fig. 7 Effect of confining pressure on **a** gas relative permeability for Pittsburg coal, and **b** Pocahontas coal, and **c** water relative permeability for Pittsburg coal. Dot, triangular, and square represent confining pressures of 1,000, 600, and 200 psi, respectively; solid line is for imbibition process and dash line for drainage process (Redrawn from Reznik et al. 1974)

air system is most water-wet at pH 10 and least at pH 7. Higher pH tends to compress the relative permeability to water, i.e., relative permeability to water decreases at a given S_w as pH increases from 2 to 10.

5.5 Saturation Sequence

Relative permeabilities of conventional sand rocks generally depend on both fluid saturation and saturation sequence (Furati 1997; Larsen and Skauge 1995; Oak et al. 1990), especially for those with strong wetting properties. Reznik et al. (1974) tested relative permeability curves of several Pittsburgh and Pocahontas coals at different confining pressures using unsteady-state method for both the drainage (gas displacing water) and imbibition (water displacing gas) processes. As can be seen from Fig. 7a and b, for all overburden pressure cases, the gas relative permeability curves in the imbibition process are lower than those in the drainage process within most saturation span. Fig. 7c shows that the curves for water during drainage are lower than that during imbibition processes, opposite to the response of gas curves to saturation sequence. Ham and Kantzas (2011) also observed that saturation sequence has an effect on relative permeability curves, but identified no regular dependence.

6 Effects of Relative Permeability on CBM Production Characteristics

6.1 Effect on Rate Curves

Several sensitivity analyses of CBM production rate to relative permeability curves have been conducted (e.g., Kissell and Edwards 1975; Remner et al. 1986; Gash et al. 1992; Stevenson et al. 1993). It can be summarized from most of the previous studies that gas production is controlled by the relative permeabilities to both gas and water. Higher relative permeability to gas gives a higher gas rate. At the same time, higher relative permeability to water or/and lower residual water saturation increases water drainage, which can result in more efficient reduction in reservoir pressure and therefore, enhance gas rate and ultimate recovery. However, Hower et al. (2003) suggested that the gas-water relative permeabilities at intermediate saturations did not greatly influence the model results in their history matching study. They attribute this phenomenon simply to the low reservoir pressures and shallow depths without detailed discussion on the underlying causes. As very limited data exists concerning the history matching by Hower et al. (2003), it is difficult to make a further comment on the study.

6.2 Effect on Type Curves

The type curves of gas and water production from a CBM reservoir describe the relationship between dimensionless rates and dimensionless times. The use of type curves provides producers with fast and inexpensive alternative to reservoir simulators for predicting CBM and water production profiles (Aminian and Bhavsar 2007; Aminian et al. 2004, 2005). Lakshminarayanan (2006) studied the effects of three parameters in the relative permeability curves (the absolute permeability, gas relative permeability exponential constant, and water relative permeability exponential constant) on type curves. The effect of absolute permeability is shown to be negligible on both type curves of water and gas, consistent with Aminian et al. (2004). Gas and water type curves are significantly controlled respectively by gas and water relative permeability exponential constants.

7 Discussion and Future Work

While a variety of subjects have been studied related to relative permeability of coals, a gap still exists between the anticipated research fruits and current study status. Further study subjects concerning the relative permeabilities of coals may be anticipated and should benefit the CBM industries:

i) Comparison of current measurement techniques. As reviewed in previous Sect. 2.1 through 2.6, various methods have been applied to obtain relative permeability curves of coals. It is of practical meaning to make a comparison of curve shapes obtained by differing methods, and reveal which method is more reliable to use, such that a guide-line can be established for deriving the relative permeability highly representative of the in situ flowing conditions. Unfortunately, such efforts have not been undertaken that includes all the above methods. The comparison only exists of unsteady-state versus steady-state method, and unsteady-state versus history matching method. Also, debate exists regarding which method should be used as a priority. For example, history matching method is suggested to be more representative of the in situ situations (Young et al. 1991a, b). However, uncertainties may exist in the data used for input, such as absolute permeability and porosity (which are typically obtained by well testing data and differing testing methods can bring out varying absolute permeability), which in turn can result in errors in estimating the relative permeability curves. In contrast, the steady- or unsteady-state method can minimize the uncertainties as in the history matching method because the curves are calculated purely from experimental data that are accurately recorded. However, as with the methods that are based on analyzing laboratory experiment data, coal cores used for testing may not fully describe the cleat characteristics that govern multiphase flow in a CBM reservoir. Besides, one cannot ascertain that the test conditions approximate the in situ conditions (e.g., stress state). Consequently, these measurements are often poorly representative of the behavior exhibited by gas and water production from a well (Young et al. 1991a, b). It would be beneficial if a full comparison of all the mentioned methods is performed to (1) understand variations as well as similarities in the curves derived with differing methods and (2) reveal where improvements are desirable. However, we are well aware of the difficulties arising here because all samples used for testing and field data for interpreting must be exactly from the same hole, and it is very likely that the comparison may not be completed within only one laboratory.

ii) Effect of pore pressure on relative permeability curves. The effect of pore pressure on evolvement of coal absolute permeability has been studied extensively, from prospective of both laboratory measurement and analytical modeling (Pan and Luke D 2012). As Chen et al. (2013) has analytically proved that relative permeability can be affected by the absolute permeability, it is reasonable to experiment on the effect of pore pressure on the relative permeability. Such subject is of great practical meaning because in the primary recovery of CBM, the in situ pore pressure undergoes continuing decline.

iii) Advanced methods for accurate determination of saturation distribution. In most previous studies measuring relative permeability of coals, saturation is derived from the standpoint view of material balance. This approach, though frequently used, may not fully reflect the saturation distribution within the core and hence bring about errors in deriving relative permeability curves. To date, advanced methods such as X-ray tomography technique (e.g., Schembre and Kovscek 2003; Dria et al. 1993; Perrin et al. 2009) and nuclear magnetic resonance (AlGhamdi et al. 2012) have been applied for determining saturation distribution with higher accuracy in measuring relative permeability of conventional reservoir rocks. These techniques may need further modifications when transferred from the conventional to unconventional rocks due to issues such as low resolution and inapplicability of current interpretation models (Shen et al. 2011). Nonetheless, if verified to be suitable for coals, they may be applied for better understanding saturation distributions in coal cores during the flooding test and hence improving relative permeability assessments.

iv) Pore-scale network modeling for understanding relative permeability of coal. Pore-scale network modeling has been demonstrated to be an effective tool for investigating multiphase flow behavior in porous media (e.g., Blunt et al. 2002, 2013; Feng et al. 2012a; Gharbi and Blunt 2012; Raoof and Hassanizadeh 2012; Spiteri et al. 2008;

Valvatne 2004). The use of pore-scale network modeling can aid not only to understand effects of factors such as wettability (and its alternation) and pore network geometry on relative permeability on a pore level, but also to predict relative permeability without conducting core flooding experiment. Unfortunately, a modified application of pore-scale modeling for CBM reservoirs has not been developed so far (Clarkson et al. 2011). Since already existed pore-scale networks can hardly account for characteristics of coal cleats (e.g., cleat spacing, aperture, length, network geometry, connectivity, compaction/enlargement), specified pore-scale modeling considering these properties of CBM reservoirs would be anticipated. If such a pore-scale model is developed, it would function as a useful tool to investigate the effect of varying factors on and to predict relative permeability of coals without conducting core flooding tests.

8 Conclusions

Relative permeability of coals is import in controlling fluid transport in both primary and enhanced CBM recovery. This paper has reviewed several subjects related to relative permeability of coals and the following points have been covered: (i) Six methods have been used to obtain relative permeability of coals, including unsteady-state, steady-state, capillary pressure, numerical inversion, history matching, and production data analysis methods; (ii) The unsteady-state method is so far most frequently used due to its operational simplicity. Inconsistency exists regarding the curve shapes derived from different methods; (iii) Relative permeability of coals is affected by varying factors. However, the effects of factors are inconclusive; (iv) More work is anticipated to be conduct on relative permeability of coals.

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Appendix A

See Table 1.

Table 1 Summary of relative permeability curves in previous literatures.

No.	Author	Method	Test fluids	Sample dimensions (diameter × length)	Basin	Sw@Endpoints*				Max. relative permeability		Sw@krg = krw*
						Endpoint 1	Endpoint 2	Endpoint 3	Endpoint 4	Gas	Water	
1	Conway et al. (1995)	Unsteady-state	gas/water	1.0 in., length n.g.	Blue Creek, Black Warrior basin	0.35	0.35	0.88	0.92	1	1	0.88
2	Durucan et al. (2013)		helium/water	25 mm, length n.g.	9ft seam in South Wales, UK	0.24	0.23	0.5	0.5	0.89	0.61	0.41
3					Splint seam, Lanarkshire, Scotland	0.65	0.69	0.88	0.85	0.84	0.57	0.79
4					Schwalbach seam in Saarland, Germany	0.04	0.22	0.79	0.59	0.9	0.18	0.58
5					Dora seam in Lorraine, France	0.07	0.14	0.72	0.67	0.9	0.74	0.59
6					No.1 seam in Saarland, Germany	0.82	0.67	0.21	0.19	0.82	0.92	0.64
7					7ft seam South Wales, UK	0.32	0.29	0.81	0.8	1	0.35	0.66
8						0.34	0.37	0.83	0.83	1	0.52	0.64
9					Tupton seam in Derbyshire, UK	0.44	0.37	0.7	0.9	1	0.79	0.61
10						0.51	0.31	0.66	1	0.98	0.69	0.6
11	Gash (1991)		helium/water	3.5 × 3.26 in.	San Juan basin	0.23	0.32	0.62	0.63	0.51	0.24	0.59
12				3.5 × 2.99 in.		0.12	0.21	0.7	0.7	0.87	0.39	0.56
13				3.5 × 4.26 in.		0.24	0.17	0.8	0.81	0.71	0.4	0.71
14				2.0 × 3.71 in.	Black Warrior basin	0.25	0.21	0.82	0.81	0.73	0.32	0.76

Table 1 continued

No.	Author	Method	Test fluids	Sample dimensions (diameter × length)	Basin	Sw@Endpoints*				Max. relative permeability		Sw@krg = krw*
						Endpoint 1	Endpoint 2	Endpoint 3	Endpoint 4	Gas	Water	
15	Ham and Kantzas (2011)		helium/brine	3.0 × 3.0 in.	Alberta Horseshoe Canyon, Canada	0.96	0.96	1	1	0.31	1	0.99
16			brine/helium			0.9	0.9	1	1	0.3	1	0.9
17			methane/brine			0.77	0.77	0.91	0.91	0.16	1	0.91
18			brine/methane			0.76	0.77	0.8	0.24	1	1	0.77
19			CO_2/brine			0.74	0.74	0.9	0.9	0.07	1	0.78
20			brine/CO_2			0.73	0.73	1	1	0.14	0.88	0.73
21			helium/brine		Saskatchewan Mannville, Canada	0.27	0.27	0.83	0.96	0.12	1	0.79
22			brine/helium			0.22	0.22	0.58	0.58	0.12	0.53	0.23
23			methane/brine			0.24	0.24	1	0.91	0.12	1	0.76
24			brine/methane			0.56	0.56	0.68	0.68	0.83	0.67	0.6
25			CO_2/brine			0.49	0.49	1	1	0.14	1	0.93
26			brine/CO_2			0.48	0.73	0.87	0.91	0.79	1	0.73
27	Meaney and Paterson (1996)		n.g.	50 × 120 mm	Bowen basin	0.82	0.82	0.93	0.93	0.41	0.24	0.89
28						0.83	0.83	0.93	0.93	0.32	0.14	0.92
29						0.57	0.57	0.96	0.96	0.14	1	0.61
30						0.69	0.69	0.82	0.82	0.15	0.57	0.72
31						0.94	0.94	0.97	0.97	0.34	0.23	0.95
32						0.93	0.93	0.96	0.96	0.12	0.25	0.95
33						0.82	0.82	0.92	0.92	0.26	0.12	0.9

Table 1 continued

No.	Author	Method	Test fluids	Sample dimensions (diameter × length)	Basin	Sw@Endpoints*				Max. relative permeability		Sw@krg = krw*
						Endpoint 1	Endpoint 2	Endpoint 3	Endpoint 4	Gas	Water	
34					Sydney basin	0.59	0.59	0.89	0.89	0.1	0.49	0.71
35						0.8	0.8	0.86	0.86	0.13	0.28	0.83
36						0.84	0.84	0.94	0.94	0.22	0.63	0.9
37	Puri et al. (1991)		helium/water		San Juan basin, USA	0	0	1	1	0.9	1	0.4
38			helium/X_brine			0	0	1	1	0.8	1	0.4
39			helium/water		Warrior basin, USA	0	0	1	1	0.68	1	0.19
40			helium/X_brine			0	0	1	1	0.58	1	0.19
41	Rahman and Khaksar (2007)		gas/water	-	Australia	0.79	0.79	0.89	0.89	0.58	0.8	0.84
42						0.63	0.63	0.79	0.85	0.12	0.5	0.68
43	Reznik et al. (1974)					0.41	0.31	1	0.9	0.33	0.26	0.59
44	Shedid and Rahman (2009)		methane/water	2.5 × 4.5 in.	Australia	0.56	0.56	0.85	0.84	0.23	0.96	0.62
45						0.63	0.63	0.85	0.85	0.12	0.95	0.68
46						0.79	0.79	0.89	0.89	0.57	0.8	0.83
47	Shen et al. (2011)		methane/water	50 × 100 mm	Qinshui basin, China	0.71	0.71	0.93	0.93	0.17	0.1	0.86
48						0.74	0.74	0.96	0.96	0.22	0.13	0.9
49						0.71	0.71	0.98	0.98	0.08	0.25	0.89
50						0.48	0.48	0.64	0.64	0.33	0.23	0.73
51						0.69	0.69	0.95	0.95	0.32	0.14	0.88

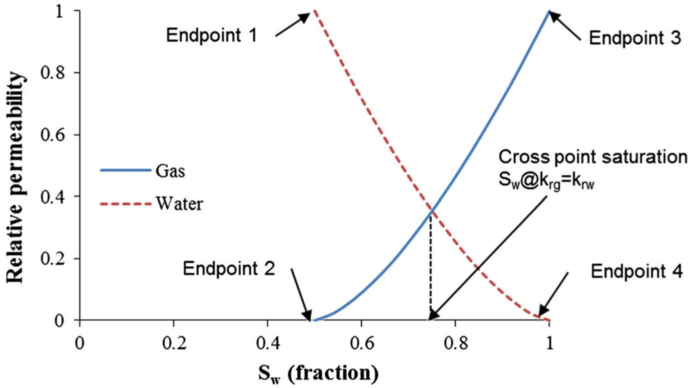
Table 1 continued

No.	Author	Method	Test fluids	Sample dimensions (diameter × length)	Basin	Sw@Endpoints*				Max. relative permeability		Sw@krg = krw*
						Endpoint 1	Endpoint 2	Endpoint 3	Endpoint 4	Gas	Water	
52	Gash (1991)	Steady-state	helium/water	3.5 × 2.99 in.	San Juan basin	0.46	0.27	0.66	0.66	1	0.29	0.65
53	Reznik et al. (1974)		air/water	1.5 in.	Pittsburgh coal	0.3	0.43	1	0.9	0.21	0.23	0.52
54	Ancell et al. (1980)	History matching			Warrior basin, USA	0.49	0.46	1	0.8	1	0.99	0.72
55	Conway et al. (1995)					0.5	0.5	1	1	1	1	0.81
56						0.35	0.45	1	0.88	0.8	1	0.82
57	Feng et al. (2012b)				Ordos basin, China	0	0.5	1	1	0.8	0.08	0.86
58	Jochen et al. (1994)				-	0	0	0.8	0.8	1	1	0.41
59	Meaney and Paterson (1996)				Bowen basin, Australia	0	0.76	1	0.94	1	1	0.84
60						0	0.53	0.99	1	1	1	0.81
61					Sydney basin, Australia	0	0.53	1	1	1	1	0.81
62						0.84	0.87	0.98	0.97	1	1	0.91
63						0.05	0.46	0.97	0.97	1	1	0.8
64						0	0.57	1	0.98	1	1	0.9
65	Karacan (2013a, b)				Black Warrior basin, USA	0	0.01	1	1	1	1	0.57-0.85
66	Ramurthy et al. (2003)				San Juan basin, USA	0	0.35	1	0.9	1	1	0.65

Table 1 continued

No.	Author	Method	Test fluids	Sample dimensions (diameter × length)	Basin	Sw@Endpoints*				Max. relative permeability		Sw@krg = krw*
						Endpoint 1	Endpoint 2	Endpoint 3	Endpoint 4	Gas	Water	
67	Wold et al. (1996)				Bowen basin, Australia	0	0.75	1	0.89	1	1	0.84
68	Young et al. (1991a)				San Juan basin, USA	0.85	0.85	0.99	0.99	1	1	0.91
69	Young et al. (1991b)				Great Divide basin, USA	0.65	0.65	1	1	0.1	1	0.69
70	Zhou (2012)				Australia							
71	Dabbous et al. (1976)	Capillary pressure				0.61	0.6	1	0.97	1	1	0.91
72						0.71	0.6	1	0.97	1	1	0.95
73	Jones et al. (1985)		gas/water	n.g.	San Juan basin	0	0.8	0.85	1	1	1	-
74	Nourbakhsh (2012)		methane/brine	1.5 × 3 in.	Sydney Coal field	0.69	0.73	1	1	1	1	0.79
75			CO_2/brine			0.58	0.59	0.98	0.98	0.96	0.81	0.7
76	Ohen et al. (1991)	Ohen et al.	methane/water	2.0 × 1.0 in.		0.02	0.38	0.98	0.86	0.96	0.96	0.61
77						0.02	0.6	0.98	0.92	0.97	0.96	0.73
78		Schembre-Kovscek	air/water, pH = 2	n.g.	Powder River basin	0	0.13	0.75	0.75	1	0.07	0.45
79			air/water, pH = 10			0	0.4	0.95	0.95	1	0.08	0.65
80			air/water, pH = 7			0	0.11	0.85	0.96	1	0.23	0.42
81	Clarkson et al. (2011)	Production data analysis			San Juan basin, USA	0.16	0.16	0.99	0.99	1	0.69	0.27

Note: * the illustration of endpoints and cross point saturation are shown in the figure below; n.g. = not given



Appendix B.

See Table 2.

Table 2 Summary of key information of investigated field cases in history matching

Ref.	Location	Coal formation or group	Coal rank	Top depth of coal seam (m)	Thickness (m)	P_L (MPa)
Ancell et al. (1980)	Oak Grove, Black Warrior basin in Alabama	Mary Lee coal	n.g.	335.28	1.58	n.g.
Conway et al. (1995)	Black Warrior basin	Blue Creek	n.g.	313.0296	2.82	0.89
Feng et al. (2012b)*	Ordos basin, Hancheng	3#, 5# and 11# formation	R_{omax} %= 1.85-2.07	311-438	1.5-2.6	2.27
Jochen and Lee (1993)	Completion Optimization and Assessment Laboratory (COAL) Site, SanJuan basin	Fruitland formation	n.g.	946.31	15.61	4.18
Karacan (2013b)	Brookwood and Oak Grove fields, Black Warrior basin, Alabama	Pratt	High-volatile A to low-volatile	182.88-365.76	n.g.	2.86
		Mary Lee		365.76-594.36	n.g.	1.71
		Black Creek		594.36-762	n.g.	4.44
Meaney and Paterson (1996)	Bowen basin Sydney basin					n.g.
Wold et al. (1996)	Dawson River, Bowen basin	Nipan 0 Seam	High- volatile bituminous, R_{omax}%= 0.81-0.89	400	n.g.	n.g.
Young et al. (1991a)	Cedar Hill in San Juan basin, New Mexico	Upper Cretaceous Fruitland formation	n.g.	n.g.	n.g.	2.28
Young et al. (1992b)	Great Divide basin, Wyoming	Rock Springs formation	High-volatile B to high-volatile A bituminous	1115-1129.34	4.42	21.26
Zhou (2012)	Unknown basin in Australia		n.g.	350-480	5.1	3.1
Ramurthy et al. (2003)	Tiffany Area, San Juan basin in La Plata County, Colorado	Upper and Basal Fruitland formations	High-volatile bituminous	804.52/813.66	6.10/4.57	3.9

Table 2 continued

Ref.	V_L (m3/t)	k_x	k_y	k_z	Porosity (%)	Gas content (m^3/t)	Reservoir pressure (MPa)	Simulator
Ancell et al. (1980)	n.g.	75	Equals k_x	n.g.	1.2	13.65	2.9	Ancell et al. (1980)
Conway et al. (1995)	20.9	66	Equals k_x	n.g.	0.53	n.g.	1.03	n.g.
Feng et al. (2012b)*	22.18	2.0-3.7	Equals kx	n.g.	1-4.4	1.98-3.35	3.11-4.39	Zhang and Tong (2008)
Jochen and Lee (1993)	7.708	10	Equals k_x	n.g.	0.06	n.g.	n.g.	n.g.
Karacan (2013b)	19.14	8.42	Equals k_x	n.g.	1.4	4.42	0.64	—
	18.86	6.24		n.g.	1.42	5.73	0.8	
	16.06	1.03		n.g.	1.87	3.93	1.48	
Meaney and Paterson (1996)								SIMED II
Wold et al. (1996)	n.g.	13	4.7	n.g.	n.g.	n.g.	n.g.	SIMED
Young et al. (1991a)	17.64	0.5-20	0.5-5.0	n.g.	0.05-0.80	14.55	10.77MPa @3259' msl	Developed by ICF
	9.87	10.5	Equals k_x	0.25	1.2	9.85 Young et al. (1992b)	10.13	COMET PC-3D
Zhou (2012)	9.2	2.8	Equals k_x	0.03	0.9	.2	3.3-4.2	SIMEDWin
Ramurthy et al. (2003)	12.26	1.5/4.5	Equals k_x	n.g.	0.25	4.69/5.58	2.414/3.255	COMET 2

n.g. = not given; kx = horizontal absolute permeability along the face cleat direction; ky = horizontal absolute permeability along the butt cleat direction; kz = vertical absolute permeability; *: the parameters are for 3# seam

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