The Impact of Pore Structure and Geometry on Petrophysical and Electrical Properties Estimation for Conventional and Tight Porous Media

Faisal Alreshedan, Chemical and Petroleum Engineering Department/University of Calgary, and Apostolos Kantzas, Chemical and Petroleum Engineering Department/University of Calgary

Abstract

Several methodologies published in the literature can be used to construct realistic pore networks for simple rocks, whereas in complex pore geometry like tight formations such construction still remains a challenge. Understanding pore structure and topology is essential to overcome the challenges associated with the pore scale modeling of tight porous media. A few papers in the literature were published to study the influence of pore structure on estimating permeability and electrical properties for simple conventional porous media and little attention has been paid to more complex and tight porous media, such as tight sands, shale and coal beds.

 A stochastic random generation algorithm was employed to assess the effects of certain pore structure on the estimation of petrophysical and electrical properties of a tight porous medium. Further, the study will emphasize on the relationship between porosity and formation factor for the case of conventional and unconventional porous media.

Introduction

Experimental measurements of macroscopic properties such as capillary pressure and relative permeability in such porous media where K < 0.1 md are costly and time consuming; studying the effect of a certain parameter is difficult due to the complexity associated with the experimental design. As an alternative approach, pore network modeling to reconstruct a physical three dimensional (3D) pore network based on pore structure and geometry can be used. Pore network modeling can give a reasonable prediction of fluid flow properties through porous media, and offers the flexibility of studying macroscopic property relationships with pore throat structure. [1]

Reconstruction of 3D porous media is of interest to, and has numerous applications in, biology, medicine, petroleum engineering, and various other areas of research because pore throat structure (e.g. pore and throat size distribution, or connectivity and geometries) are critical elements in the reconstruction of a realistic network of porous media. Pore geometry in tight gas reservoirs represents a challenge to visualize the gas flow in such porous media. A basic understanding of pore geometry and rock properties is essential for the successful reconstruction of a 3D pore network and eventually evaluation of the macroscopic properties through tight porous media. In pore network modeling, the pore space is visualized as a network of pores connected by throats. Pore space properties can then be extracted through statistical methods,x-ray micro-tomography,or process-based reconstructions. [1, 2]

Method

Imperial College Consortium softwares on Stochastic Random Generation and Pore-Scale Modeling (Idowu and Blunt 2009,Valvatne and Blunt 2004) will be used as a starting stage in modeling pore networks for tight gas formation and gas flow transport properties. [2, 6]

An extension will be implemented to the stochastic random software to generate a realistic 3D pore network while knowing only the pore and throat size distribution. The Weibull equation will be used to predict the other network elements. The same procedure as Imperial College was followed to build the random 3D pore network with an exception.

An equivalent 3D pore network of Berea Sandstone was generated based on published pore and throat size distributions by Imperial College. The estimated porosity and absolute permeability of the reconstructed pore network were in good agreement with the lab measurements. The objective of the paper was achieved first by shifting each element of the pore structure; i.e. pore size, throat size and coordination number independently, two elements combined and all three elements together producing a realistic tight porous media and then estimate porosity, absolute permeability and formation factor. Secondly, pore and throat geometries are studied in the case of tight porous media to assess the impact of estimating formation factor and cementation exponent from Archie's equation and Dual-Porosity model.

1. Pore Structure Effects

The objective here is achieved by shifting each element of the pore structure (pore size, throat size and coordination number) independently, combining two elements, and then combining all three elements together, producing a realistic tight porous media. Table 1 illustrates the variation in porosity, absolute permeability, formation factor and cementation exponent values for conventional porous media.

Table 1: Porosity, permeability and formation factor estimation – Conventional porous media

Case No.	1	2	3	4	5	6	7	8
	Modeled	Pore Size	Throat Size	Coord. No.	Pore /Throat Size	Pore/ Coord	Throat/ Coord	All Combined
Porosity (%)	24	6.6	22.08	21.68	6.04	5.7	21.792	5.5
Permeability (md)	3296.92	320.46	603	19	201.4	6.1	1.4	1.17
Formation Factor	11.8	38.7	20	318.3	46.9	816.5	726.13	1258.8
m, using Archie's Equation	1.73	1.34	1.98	3.77	1.37	2.34	4.32	2.46

Figure 1 shows variation on porosity, permeability and formation factor estimation due to changes in certain pore structure. It can clearly be seen that when the pore size is reduced by half, the estimated porosity dropped from 24% to 6.6%. The estimated absolute permeability declined in all cases, and it can be concluded that all three elements have an effect on permeability estimation. Overall, the value of formation factor increases with changes to these elements as shown in Figure 1. Looking at single element cases, all elements have influence to some degree on predicting formation factor but the coordination number has the more effect. The incensement in its value becomes more significant at pore/coordination or throat/coordination factors.

Formation factor values are plotted with the estimated porosity for all physical 3D porous media in semi-log and Cartesian scale as shown in Figure 2a and 2b, respectively. No relationship can be defined between formation factor and porosity due to the difference in petrophysical and electrical properties for all cases. Figure 2c illustrates the relationship between formation factor and permeability for the case of conventional porous medium. Formation factor will decrease with increasing absolute permeability. In Figure 2d, the absolute permeability versus porosity in log-log scale is plotted, and it can be seen that those cases having low estimated porosity plotted together on the left side where other cases that have higher porosity and absolute permeability were drawn together on the right side of the graph.
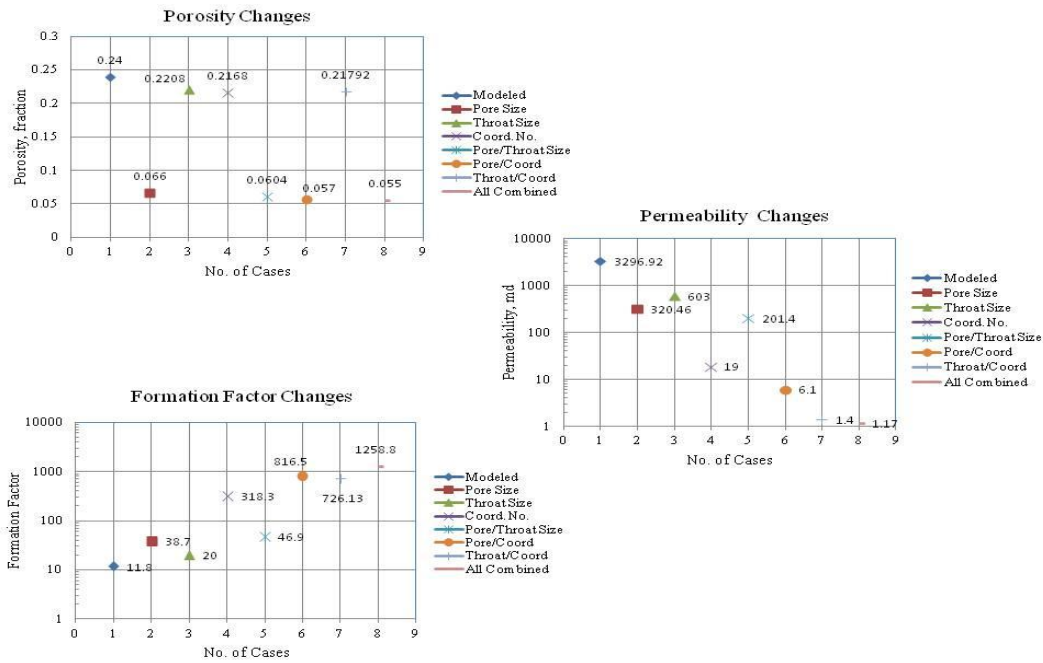

Figure 1: Showing pore structure influence on porosity, formation factor and permeability estimation for Conventional porous media. It shows Porosity, Formation factor, and Permeability variation with respect to pore throat size and coordination no.
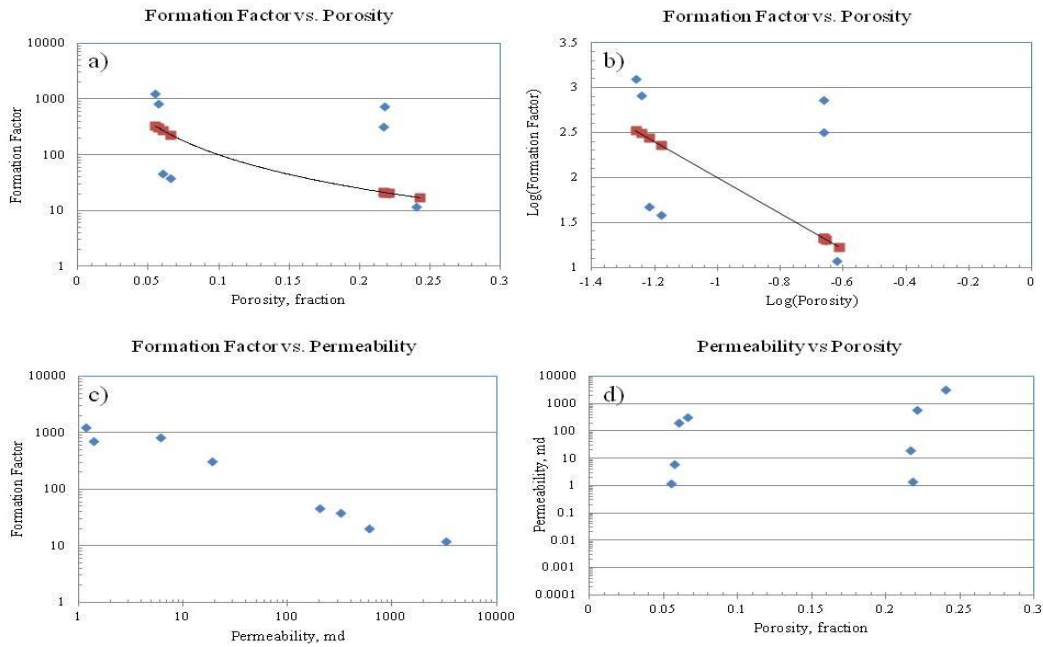
Figure 2: (a) Semi-Log plot for predicted and estimated values of formation factor vs. porosity for all cases. Solid line corresponds to Archie's Law estimation @ m=2 and a=1. (b) Normal scale plot for estimated values of formation factor vs. porosity. (c) Log-Log plot showing the relationship between formation factor and estimated permeability. (d) Semi-Log plot showing the relationship between predicted permeability and calculated porosity for all cases.

2. Pore Geometry Effects

Representative 3D pore networks of tight porous media are developed to study the magnitude of the impact of pore and throat geometries on estimating porosity, absolute permeability and formation factor. Pore structure will be assumed constant and the same, as in Case no. 8 from the previous study. Table 2 illustrates the difference in estimating porosity, absolute permeability and formation factor.

Table 2: Porosity, permeability and formation factor estimation – Tight porous media

Case No.	8	At 100% Square Throat Geometry			At 100% Circle Throat Geometry			At 100% Triangle Throat Geometry		
	All Combined (0)	100% Triangle (1)	100% circle (2)	100% square (3)	100% Triangle (1)	100% circle (2)	100% square (3)	100% Triangle (1)	100% circle (2)	100% square (3)
Porosity (%)	0.055	0.067	0.0143	0.0183	0.0665	0.0144	0.0182	0.068	0.0152	0.019
Permeability (md)	1.17	0.53	0.45	0.53	0.42	0.36	0.36	1.52	1.15	1.22
Formation Factor	1258.8	1908.00	2997.15	2470.92	2126.44	3211.16	2717.54	953.95	1993.09	1678.96

Porosity, absolute permeability and formation factor values were plotted versus pore geometric changes and throat geometry as shown in Figures 3. Pore geometry variance has more of an effect on porosity estimation than throat geometry variances. However, pore and throat geometries have a huge effect on estimating absolute permeability and formation factor. Thus, considering only porosity to describe microscopic properties for a certain porous media is not adequate[8]. It can be seen from Table 2 and Figure 3 that at 100% circular pore and throat geometry, physical 3D pore network was produced with lower porosity and permeability estimation.
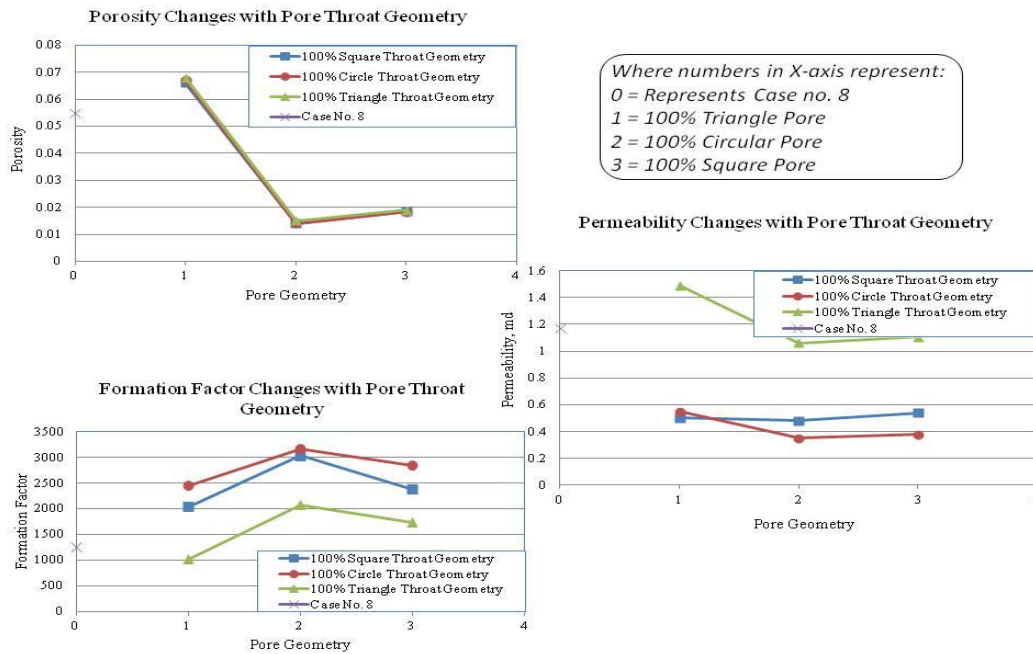

Figure 3: Showing pore throat geometries influence on petrophysical properties estimation for tight porous media. It shows Porosity, Formation factor, and Permeability variation with respect to pore throat geometries variation.

3. Estimation of Porosity Exponent m for Tight Porous Media

Tight gas reservoirs have been characterized in the literature by dual porosity models in which secondary pores represent the large fraction of void space connected to each other by slots/fractures. Aguilera et al. (2007) studied the possibility of using a dual porosity model to simulate the experimental data obtained by Byrnes et al. (2006). The results for a dual porosity show a reasonable fit between modeled and experimental data.

Thus, based on previous pore level scale results of tight porous media, the cementation exponent m was calculated using two different equations: Archie's Law (1950) and Dual-Porosity Model (Aguilera 2008). Further, formation factor will be estimated as a function of the dual porosity exponent m. The assumptions used in estimating m using the Dual-Porosity model are similar to those published by Byrnes et al. (2006):

mb = 2.0

mf = 1.0

$$\phi_2 \quad = \quad 0.35\%$$

The Dual-Porosity Exponent equation by Aguilera (2008) is as follows:

$$m = \frac{\log\left(\frac{1}{\{(v\phi)^{m_f}+[1-(v\phi)^{m_f}]/\phi_b^{-m_b}\}}\right)}{-\log\phi} \tag{1}$$

Where,

$$\phi'_b = \frac{\phi - \phi_2^f}{1 - \phi_2^f} \tag{2}$$

$$f = m_f - (m_f - 1)\frac{\ln\phi}{\ln\phi_2} \tag{3}$$

$$\phi_m = \phi_b(1 - v\phi) \tag{4}$$

$$v = \frac{\phi_2}{\phi} = \frac{\phi - \phi_m}{\phi} = \frac{\phi - \phi_b}{\phi(1 - \phi_b)} \tag{5}$$

Figure 4a represents the relationship between porosity and porosity exponent that is calculated using Dual-Porosity model and Archie's Equation in the generated tight pore networks. Porosity will decrease with lower cementation exponent as shown by tow method. However, in the case of Dual Porosity model, the porosity exponent increases as porosity is increasing till it reaches to a constant value as porosity increases which is not the case for Archie's model. As porosity values increase, porosity exponent will continue increasing and it exceeds the value of 3 which is too high for tight porous media. Normally, the value of m used for tight gas formation is close to 2 or less (e.g. 1.85, 1.9)[4]. The relationship between porosity and formation factor has become more defined after using the Dual-Porosity exponent as shown in Figures 4b and 4c. The data points differ from the power function. In 2012, Xiao-peng Liu et al showed in their experimental study for tight gas sands is that the relationship of formation factor and porosity is not a power function trend. The obtained formation factor using the Dual-Porosity exponent and Archie's porosity exponent was plotted with predicted absolute permeability, as shown in Figure 4d.

Results from using the Dual-Porosity model in the generated tight porous media were compared and validated with published laboratory data. The estimated porosity exponent for the generated tight pore network were plotted with the Byrnes et al. (2006) laboratory data as shown in Figure 5, and the estimated data fit well. Further, the estimated formation factor using the Dual-Porosity exponent follows Byrnes et al. (2006) and Liu et al. (2012) experimental measurements trend. The data will bend to the left with porosity decreasing, as shown in Figure 6.
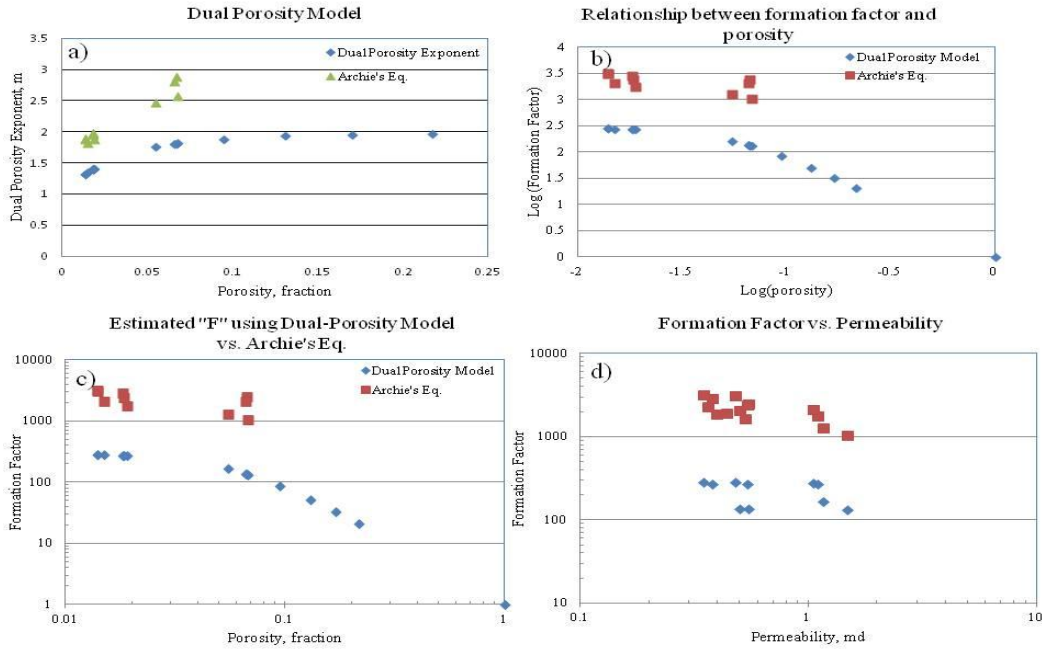
Figure 4: (a) Porosity exponent estimated for tight porous media using Archie's Law and Dual Porosity assuming slot porosity = 0.35% and cementation exponent of fracture = 1.0. (b) Linear coordinates showing the relationship between porosity and formation factor obtained using Archie's Law and Dual Porosity Model. (c) Log-Log scale showing same relationship between and formation factor as linear coordinates plot. (d) The relationship between permeability and formation factor obtained using Dual porosity model electrical current modeling.
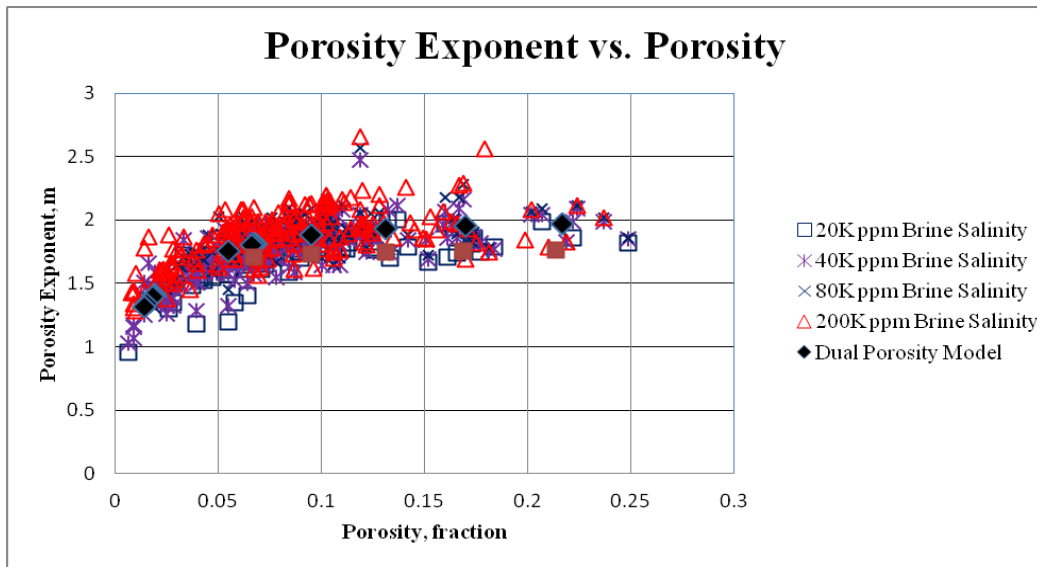

Figure 5: Comparison between estimated porosity exponent from pore network and
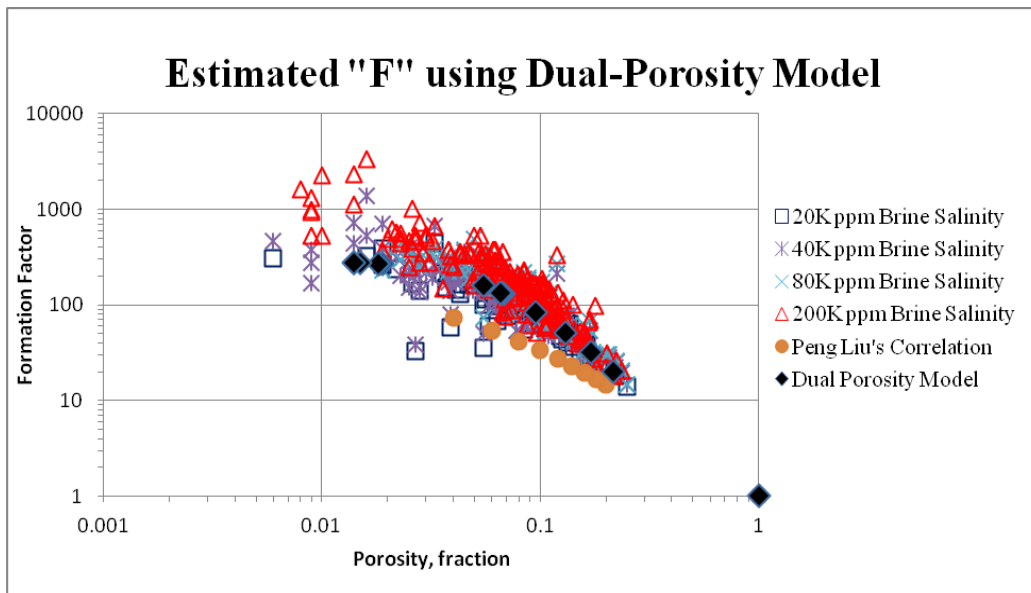
Byrnes et al. (2006) laboratory data

Figure 6: Comparison between estimated formation factor using dual porosity exponent

Byrnes et al. (2006) and Liu et al. (2012) experimental measurements

Conclusions

It can be concluded, then, that understanding pore throat geometry and pore structure in tight gas reservoirs are essential for constructing a physical, realistic 3D void space as well estimating the micro and macro gas flow properties through such porous media. Thus, in this work it has been shown that:

- The impact of pore size distribution on porosity estimation and the significant effect of combining throat size distribution and coordination number on permeability values.

- The pore structure elements influence formation factor calculation. However, the coordination number has the highest impact.

- The pore geometry has magnitude effect on porosity estimation whereas pore and throat geometries have significant effect on permeability and formation factor estimation.

- The formation factor and porosity relationship differs from power function. The data will bend to the left with decreasing in porosity. The relationship between formation factor and porosity has become more defined after using Dual Porosity Model in estimating porosity exponent.

- Thus, the need to implement dual porosity concept in reconstructing and simulating micro and macro gas flow properties through a tight porous media.

Acknowledgements

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Nomenclature

m $\quad\quad$ = Dual porosity exponent

m_b $\quad\quad$ = Porosity exponent of the matrix system

m_f $\quad\quad$ = Porosity exponent of the fracture system

υ $\quad\quad$ = Partitioning coefficient

ϕ $\quad\quad$ = Total porosity

ϕ_b $\quad\quad$ = Matrix block porosity attached to the bulk volume of the matrix system

ϕ_b' $\quad\quad$ = Matrix block porosity affected by m_f

ϕ_m $\quad\quad$ = Matrix block porosity attached to the bulk volume of the composite system

ϕ_2 $\quad\quad$ = Porosity of natural fractures

f $\quad\quad$ = Constant affected by m_f