Study of Apparent Permeability in Shale Gas Reservoirs

Dr. D. K Gupta, Dr. Uday Bhan, Mr. K. Vamsi Krishna & Mr. Dinesh Alluka
University of Petroleum & Energy Studies (UPES),
Dehradun, India.

***Abstract:* - The permeability of reservoir plays an important role in modeling gas production form reservoir. The transport mechanism in shale gas reservoirs is significantly different from conventional reservoirs. As the gas is mostly stored in the organic matter, the transport mechanism of this gas mainly depends on the diffusivity and desorption of gas from the source. To have better understanding of the flow mechanism the concept of relative permeability is very important, which has more impact on the well performance in shale reservoirs.**

In this paper, we have explained about importance of relative permeability and the different techniques to determine the relative permeability.

1.0 INTRODUCTION:

Shale gas is a natural gas, formed in shale formations. These formations behave as both the zone of production (source) and zone of accumulation (reservoir). Shale formations are self-sourcing rock where organic matter is stored. They referred as the unconventional reservoirs due to their low permeability .Permeability refers to capacity of porous media to transmit the fluid, which shows contrastive with the conventional gas reservoirs. The very low permeability of rock causes the gas to trap and prevent it from migration. The gas trapped in such formations in the form of absorbed organic material or trapped in tiny pores of rock. While considering gas potential, apart from permeability other properties of shale are total organic content (TOC) and thermal maturity. All through the shale gas is clean, because of its low hydrodynamic conductivity of shale and structural complexity it is hard to extract from the pay zone. With the increase in interest to extract the shale gas many special techniques from drilling have been implemented in many shale gas basins. The techniques to explore and produce the shale gas vary with conventional gas techniques. Various shale gas basins in the world and comparative analysis of estimated technically recoverable shale gas from various countries are provided in the below figures.

Over View of U.S. Shale Gas

The shale gas E&P operations in US has become a boon and altered the natural gas production and supply. The US had gained the significant momentum from the year 2008-9 in production of gas. The production in Marcellus, Barnett, Haynesville and Fayetteville gas plays has most actively produced basins.

2.0 Shale Gas Storage:

In contrast, with sandstone and limestone formations in the shale gas formations the gas forms and remains in the formation itself. The porosity values of shale gas systems range from 2-15%, in typical depth of Barnet shale's. The gas may be stored in the four different types of porous media in productive gas shale reservoirs. They are

- Non organic matrix
- Organic matter
- Tiny pores and natural fractures.
- Hydraulic fractures

Gas stored in shale formations is of three different types

- Free gas is the gas, which is attached with organic (kerogen) matter or clay minerals. This gas trapped in the pores, fractures and rock matrix. The amount of free gas increases with the increase in organic content or surface area of kerogen material.
- Absorbed gas is the gas, which trapped in the tiny pores in the rock. This gas also traps in the fractures, which are natural or hydraulically fractured.
- Solution gas is the gas, which is attached with the liquids.

The figure shown below types of storage areas of shale gas.

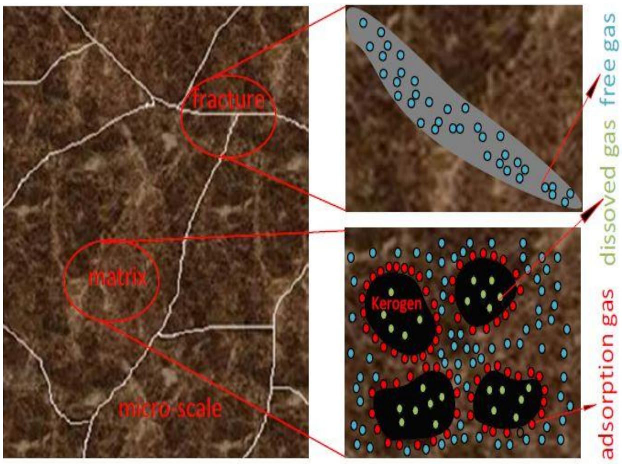

Figure 1:- Gas storage areas in shale gas reservoir.

Higher free gas in shale wells leads to higher initial rates of production due to trapped in the fractures and pores which is easier to flow towards the well bore than compared relatively with absorbed and solution gas. Once all free gas is released for a period of time showing the rapid decline flow rate, then absorbed gas is slowly released from shale.

"Shale gas differs in possessing the characteristics of gas absorption on the surface area associated with organic matter
and clay. The relative importance of free gas Versus absorbed gas is a function of pore type, network and mineralogy, the amount of organic matter present, rock structure, diagnosis, reservoir pressure and temperature". (Bustin, et al., 2008)

Pore type, network and mineralogy: Shale matrix is composed of clay minerals, quartz, pirate and organic matter. In the shale matrix, two types of matrix pores exists "micro scale pores" and "nano scale pores". Nano- scale pores are situated throughout the kerogen material and clay-rich mud rock. Micro scale pores are seen mostly in silica-rich mud rock. Most shalesin Barnett, Fortwarth are composed of pyrites and kerogen material in pores. Shale gas flows through a pore network from nano scale to micro scale pores. Flow from micro scale pores, generally follow "Darcy equation" and are referred as "Slip flow". Whereas flow from nano scale pores are generally dominated by both "Slip flow" and "Surface interactive pores".

Organic Matter:-

The organic matter in shale acts as the separate porous media. Pore spaces in organic matter are created due to hydrocarbon generation, these pore spaces can in turn absorb and store free gas. The free gas stored in matrix directly increases with total organic content (TOC). When TOC is zero, it is considered as the free gas stored is in the non-organic matrix. Mechanism of free gas flow from organic content are speculative, but oil wet organic matters resembles that flow hydrocarbons through the organic matter. The existence of non-organic matrix along with free gas stored in organic content medium can't be separated. The role of organic matter can be important in terms of petro physical properties as well as migration and production.

Pore space in organic matter can be five times higher than that in the nonorganic matrix. If Organic matter is oil wet, and associated pores acts as nanofilters for the flow of hydrocarbon, by modeling that fluid flow in organic matter is mostly single phase." (Javadpour.F, 2007)

"Due to high porosity, predominantly single-phase flow and the gas slippage effect, permeability of gas in organic matter is significantly higher than that in the nonorganic matrix and tends to increase gas permeability in gas-shale. The pore network in organic matter (porous media), can be larger than compared with the fractures, this could be the hidden pathway to high gas production for shale gas when contacted or connected with natural and hydraulically created fractures."

3.0 Gas Transport Mechanism:

Fluids move through a porous media by various transport processes. In general, the transport of gas is done by considering three elements of transport phenomena like momentum transport, energy transport, and mass transport. The transport of gas in shale reservoirs is described by mass transfer with diffusion under isothermal conditions i.e. under constant temperature. Adsorption effects occur mainly in the organic porosity.Gas solubility in water is considered when water is present, which is introduced into the shale during the hydraulic fracturing. When water is present, transport of water with in the rock has to be considered. The effects of capillary pressure play a great role in the fluid transport due to the nanometer-scale Pore throat radius. Gravity effect on flow is concerned when water is present in the transporting fluid.

Schepers (2009) initially didn't indicate the diffusion of adsorption gas into the fracture system as well when it diffuses into the matrix pore system. Secondly, the fluid flow within the matrix micro-pore system and the flow from matrix micro-pore system to fracture system are given by darcy-flow, which means the flow of gas within the porous media is due to pressure gradient.

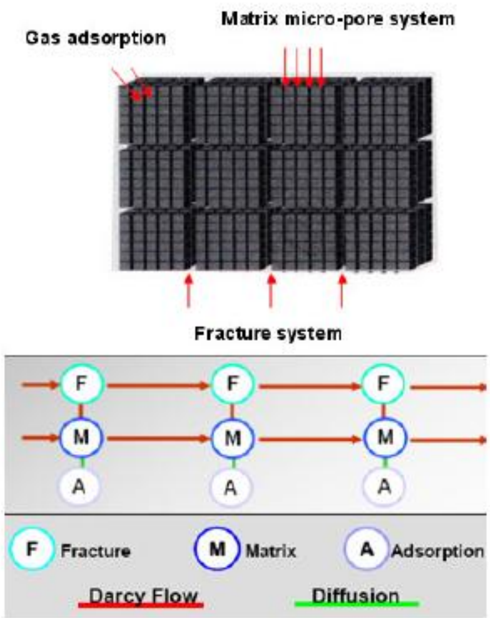

Figure:-2 Gas Transport Mechanism in shale gas reservoir .

Wang and Reed (2009) included two types of porous media in gas shale's, pores and fractures. Pores are subdivided into two types as organic pores and non-organic pores, the fractures are subdivided into two types as natural fractures and hydraulically induced fractures. The organic pore inside the matrix is believed to act as a porous medium for the gas to flow through the matrix.

Schepers, stated that the release and transport mechanisms are characterized by desorption, diffusion and Darcy-flow. Moreover, the flow in the porous medium is the dominant flow mechanism than the flow by diffusion mechanism.

The entire transport mechanism can be described as follows.

1) Free gas will flow through matrix pores (primary porosity) into the fracture system (secondary porosity) due to pressure difference occurred due to fluid flow in porous media.

2) Now, the free gas will flow to the wellbore through fractures.

3) For adsorbed gas, desorption will occur when the pore pressure decreases, and adsorbed gas molecules have the potential to move and diffuse to the pore space from particle surfaces.

4) Now, the adsorbed gas becomes free gas and the further transport of this free gas will follow the same way with the original free gas, and the flow mechanism through the matrix pore system and fracture system is also the same.

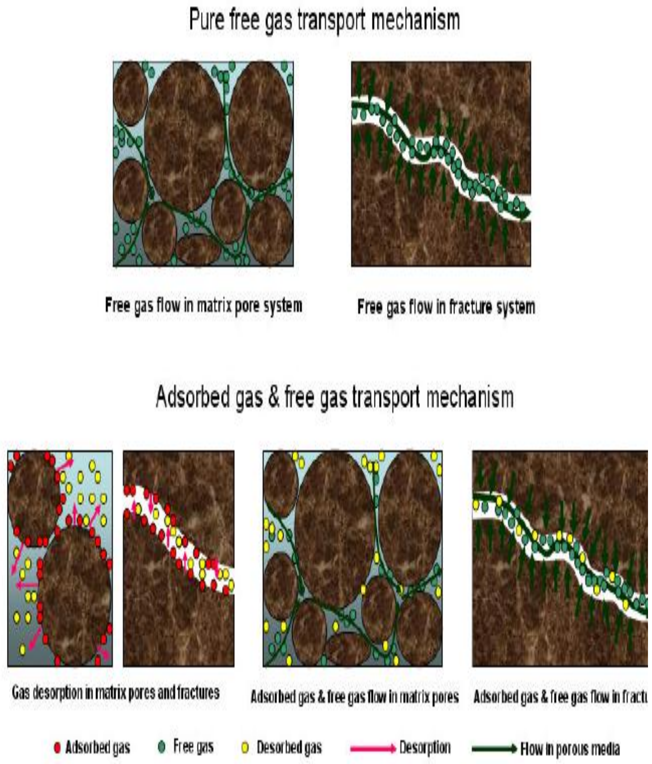

Figure :-3 Gas Transport Mechanism(Adsorbed Gas and Free Gas) in shale gas reservoirs.

4.0 Modeling of Shale Gas:

Robert (Loucks et al. 2009) found that shale gas strata constitute of micro and nano pores, with the majority being nano pores. These fact states that importance of studying how gas flow is associated in nano pores (nano tubes) is critical for production and stimulation of shale gas reservoirs.

Several modeling techniques are developed and adopted to stimulate flow of gas in nano pores. Some of those techniques include

1. Lattice Boltzman method to study gas flow (Hornyak ., 2008)
2. Molecular-dynamics-method. (Bhattacharya and Bird., 1994).
3. Direct stimulation Monte Carlo to study characters of gas flow. (Karniadakis and Beskok, 2002)

All these methods showed impractical when moving to the systems, which are larger than few microns. Still research is going on to derive an equation for volumetric gas flow law. For volumetric gas flow through a single-pipe were derived by Beskok and Karniadakis (1999) by Hagen–Poiseuille-type equation.

By considering the Knudsen diffusion and advection flow, Javadpour in 2009 proposed the concept of apparent permeability, which would be applied for pore scale and gas flow modeling for shale gas.

4.1 Apparent-Permeability: (Javadpour)

According to Folk, who developed classification of mud rocks on basis of fissility. The fissility refers to paper like parting. Javadpour detected the nano pores and nano grooves in mud rocks by AFM (atomic force microscopy). After detection, there work was concentrated on developing governing equations to describe the gas flow in nano pores. The equations for flow of gas in small pores were distinguished from Darcy equations.

When equilibrium, gas molecules are distributed throughout the formation. In a way such that fee gas occupied in pores spaces, absorbed gas covered the surface of kerogen and also dissolved into kerogen as solution gas. During the drilling operations, the equilibrium disturbs as a result the free gas escapes into well bore or fractures first followed by gas desorption from kerogen, which changes the concentration equilibrium between kerogen and its surface. Finally, gas diffuses out from the kerogen. Javadpour work suggested that there would overlap between the above process and rate of diffusion from kerogen contrasts from Knudsen diffusion.

The advective - diffusive - desorptive equation:

$$\frac{\partial c}{\partial t} + U.\nabla c - D{:}\nabla^2 c - \kappa c = 0 \ldots\ldots\ldots \quad (1)$$

The above equation is the mass balance equation gas in an element of producing mud rocks. In which, first term indicates the temporal changes of concentration, second term denotes the advection, third and fourth term refers to Knudsen diffusion and desorption.

The Darcy law could be applicable for nano pores because of difference between fluid mechanics of nanopores (unconventional) and micro pores (conventional).A theoretical approach to determine the gas flow in shale by deriving the formula for “apparent permeability” which distinguishes with Darcy equation. The derived formula is compactable with Darcy equation for commercial reservoir stimulators. (Javadpour.F 2007)

Gas Flow in Nano Pores:

The combination of Knudsen diffusion and pressure forces are presented in the below equation which would result to total mass flux of gas in a nano pore.

$$J = J_a + J_D \quad \ldots\ldots\ldots\ldots\ldots\ldots \quad (2)$$

Where, J represents total mass influx and the first term on right hand side refers to advective flow due to pressure forces, second term refers to Knudsen diffusion.

For shale gas:

$$J_a = U.\nabla c$$

$$J_D = -D_K : \nabla\nabla c$$

Where U refers to advective velocity and D_K refers to Knudsen diffusion.

Gas Flow Due To Knudsen Diffusion In A Nano Pore:

Mass of gas flux by only diffusion by diffusion with negligible viscous effect can determine as:

$$J = \frac{M D_K}{10^3 RT} \nabla P \ldots\ldots\ldots\ldots\ldots \quad (3)$$

Knudsen diffusion constant can described as:

$$D_K = \frac{2r}{3}\left(\frac{8RT}{\pi M}\right)^{0.5} \dots\dots\dots\dots \quad (3.1)$$

Gas Flow in Nano Pore Due To Pressure Forces:
Hagen-Poiseuille's equation is

$$J_a = -\frac{\rho r^2}{8\mu}\nabla p \dots\dots\dots\dots \quad (4)$$

From above equation, the mass influx J_a refers for ideal in a laminar flow in circular tube with neglecting length of entrance effect.
Apply ideal law gas law to Hagen-Poiseuille' s equation

$$J_a = -\frac{r^2}{8\mu}\frac{\rho_1}{p_2}\nabla p^2 \dots\dots\dots \quad (4.1)$$

To determine slip velocity in nano pores, F theoretical dimensionless coefficient.

$$F = 1 + \left(\frac{8\pi RT}{M}\right)^{0.5} + \frac{\mu}{\rho_{avg}\, r}\left(\frac{2}{\alpha} - 1\right)$$

The total mass flux through a nano pore by the combination of Knudsen diffusion and slip flow described as:

$$J = -\left[\frac{2rM}{3\times 10^3 RT}\left(\frac{8RT}{\pi M}\right)^{0.5} + F\frac{r^2\rho_{avg}}{8\mu}\right]\frac{(p_2 - p_1)}{L}$$

Apparent Permeability:
Volumetric flux based on Darcy equation for compressible gas

$$\frac{q}{A} = -\left(\frac{K_D\rho_{avg}}{\mu}\right)\frac{(p_2 - p_1)}{L}$$

K_D= Darcy permeability
Volumetric gas flux for a nano pore from total mass flux of a nano pore by a combination of Knudsen diffusion and slip flow.

$$\frac{q}{A} = -\left[\frac{2rM}{3\times 10^3 RT\rho_{avg}}\left(\frac{8RT}{\pi M}\right)^{0.5} + F\frac{r^2}{8\mu}\right]\frac{(p_2 - p_1)}{L}$$

The above equation implies Darcy equation by increasing pore size or pore pressure.
On comparing the above equations of volumetric flux, a new term called as apparent permeability,k_{app} , for flow of gas in shale gas or mud rock system is described as:

$$k_{app} = \frac{2r\mu M}{3\times 10^3 RT\rho_{avg}^2}\left(\frac{8RT}{\pi M}\right)^{0.5} + F\frac{r^2}{8\rho_{avg}}$$

The above is equation of permeability is not only the property of rock or shale gas system, but also depends on the flowing gas at particular pressure and temperature.

$$\frac{kapp}{k_D} = \frac{2\mu M}{3\times 10^3 RT\rho_{avg}^2}\left(\frac{8RT}{\pi M}\right)^{0.5}\frac{8}{r} + \left[1 + \left(\frac{8\pi RT}{M}\right)^{0.5}\frac{\mu}{\rho_{avg}\, r}\left(\frac{2}{\alpha} - 1\right)\right]\frac{1}{\rho_{avg}}$$

The equation represents smaller the pore size, larger the difference between apparent permeability and Darcy permeability
Apparent permeability is divided with Darcy permeability to tackle with field problems like gas producing from the mud rock strata is higher than excepted gas production from these reservoirs.

4.2 Gas Flow in Nano Pore:_
To understand, gas flow in shale gas reservoir in view of "kerogen" as a source of gas. Depending on, Knudsen diffusion and slippage were considered to model flow of shale gas in nano pores.

With increase in scientific achievements, we are able to look in the nano scale of shale gas reservoir. Figure 4 & 5 show the scanning electron microscope (SEM) images of shale samples by Ambrose et l., and Loucks et al., respectively. From the below figures the red circle sections indicate the reservoir matrix which composed mainly of kerogen/organic matter, silica/clay and some minerals like quartz and feldspar.

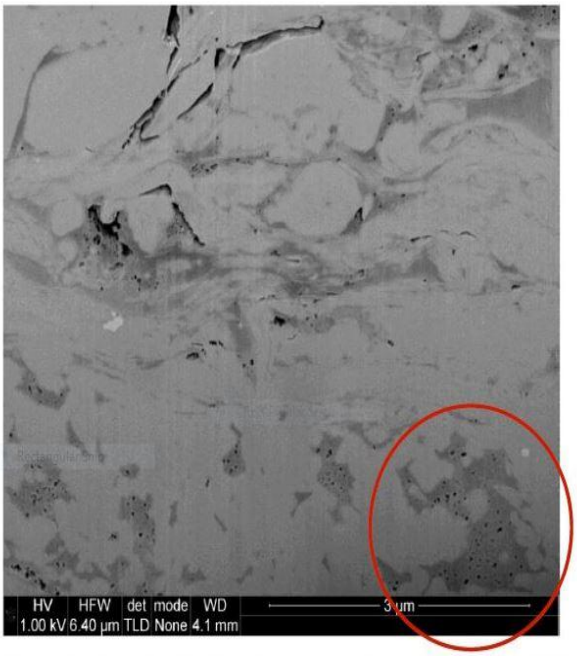

Figure 4- SEM image of shale gas reservoir (Ambrose et al., 2009)

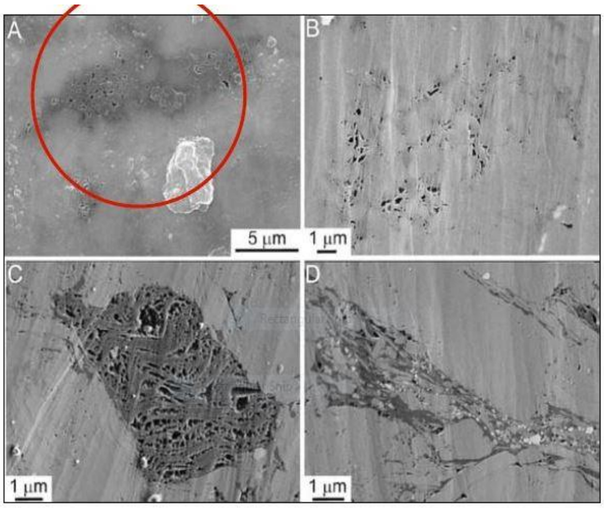

Figure 5- SEM of shale gas reservoir showing location of pores and kerogen (Loucks et al., 2009)

From figure 6, the free gas present in pore space, absorbed along the pore walls and some gas is releasing or diffusing out from the kerogen. Javadpour 2009 statistically proved the significant quantity of gas diffusing out from kerogen.

Whereas, conventionally many authors considered very low quantity of gas diffuses out of kerogen.

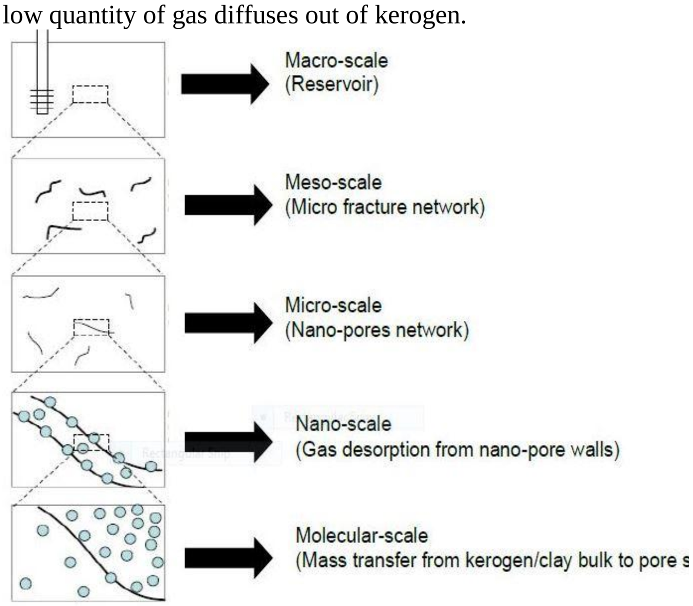

Figure 6- from macro to nano scale (Javadpour et al., 2007)

We are considering kerogen as source of gas. The basic consideration of this model is the kerogen saturated with gas at a particular pressure before it could liberate into pore.

For this modeling technique, we have considered the saturation and diffusivity constant values in correspondence to bitumen. It may be practically impossible for determination of gas solubility in kerogen at a particular pressure and temperature. Whereas, bitumen is a product of kerogen digenesis (chemically).

Approach:

Here, Single nano pore is represented by a cylindrical tube surrounded by kerogen. The figure 4, shown below indicates gas present in nano pores is free or compressed gas which is also observed at the pore walls and dissolved in kerogen considering the left boundary of the pore open to well bore or fracture(constant pressure) and right boundary is a no flow boundary.

At first the free gas flows out, when well is open to flow with pressure drops gas desorbs from the pore walls and gas starts diffusing out from the kerogen.

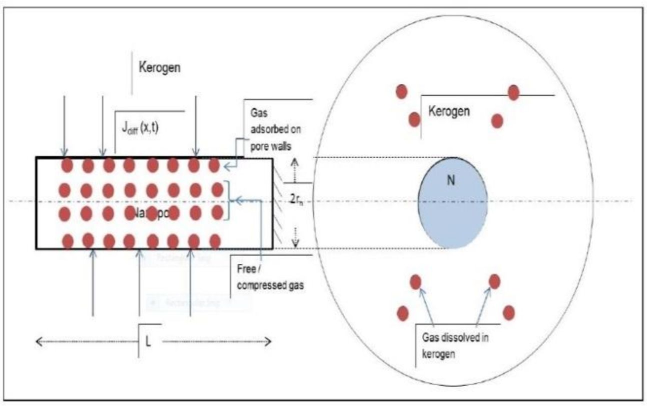

Figure 7- Model to illustrate flow in nano pore.

The below flow gas equation in nano pore was formulated taking in account Knudsen diffusion, gas desorption, slippage effect and gas diffusion from kerogen.

$$\frac{M}{RT}\frac{\partial y}{\partial x}\left(\frac{k_{app}}{z\mu}\frac{\partial p_n^2}{\partial x}\right) - \frac{\rho_{ntp}}{SV}\rho_{bi}G_L\frac{4}{r_n}\frac{b}{((1+bp_n)^2)}\frac{\partial p_n}{\partial x} + \frac{4}{r_n}D_k\frac{\partial C}{\partial r}\bigg|_{(r=r_n)} = \frac{M}{RT_Z}c_g\frac{\partial p_n^2}{\partial t}$$

First term refers to second term refers to third term refers to

4.3 Flow Characteristics Of Shale Gas: Knusden Number

Many shale gas formations have pore scale values vary in the range of one to hundreds of nanometer. The flow associated across these nano-scales pores deviates from Darcy's law. Gas slippage effects were modeled to character the non-darcy flow mechanism, which are based on different pore scale. Many research studies have proved that it was very important to study non-darcy flow mechanisms and governing equations for gas flow in nano pores of organic media (porous media) in shale gas reservoirs. The complicated pores in gas shale systems could be categorized on basis of pore spaces. Experiment conducted on Barnett shale by mercury intrusion showed that the range of pores are around 2-50nm, especially main pore size is about 2-20nm. Depending on the Knudsen number, relationship between flow characteristics and pore size can be built.

Knudsen number= $\frac{\lambda}{d_{pore}}$

λ = free mean path of gas molecule

d_{pore} = charcteristic length of channel

The flow characteristics vary with Knudsen number, and the flow regime can categorized as slip flow, continuous flow, transition flow and molecular free movement because of Knudsen number.

Slip Flow:

When the Knudsen number is ranging from 10^{-3}to10^{-1}then flow can be predominant with slip flow. The effects of collisions between molecular layers are according to the boundary conditions in slippage effect presented by Karniadas et al (2005)

To stimulate the slippage velocity in nano pores, Javadpour F et al(2009) introduced the dimensional co-efficient *F:*

$$F = 1 + \left(\frac{8\pi RT}{M}\right)^{0.5} + \frac{\mu}{\rho_{avg}r}\left(\frac{2}{\alpha} - 1\right)$$

Javadpour.F et al, obtained mass flow slip flow regime

$$J_{slip} = F\frac{r^2\rho_{avg}}{8\mu}\nabla p$$

Continuous Flow Regime:

The continuous flow exists when Knudsen number >10^{-3}, whose momentum transfer is controlled by gas viscosity. The typical continuous gas model can be considered as described, as below equation on basis of raise in Knudsen number, with reduction in collisions among the molecules and as molecular mass is intensified.

$$J_a = \frac{\rho\nabla p k_D}{\mu}$$

$$J_a = \frac{\rho r^2}{8\mu}\nabla p$$

Transition Flow Regime:

In Transition flow regime is a gas flows with Knudsen number of 10^{-1} to $10^{1.}$ The gas transport model for this regime is done by weighted slip flow model and Knudsen diffusion mode. (Zhang, et al. 2013).

The mass flow of unit area is weighted with slip flow model and Knudsen diffusion modal.

$$J_T = f \times F\frac{r^2\rho_{avg}}{8\mu}\nabla p + (1-f) \times \frac{2rM}{3 \times 10^3 RT}\nabla p\sqrt{8RT/\pi M}$$

Molecular Free Flow Regime:

Gas flow in this molecular free flow regime when, Knudsen flow range is over 10^1.

$$J_d = -D_{kn}\nabla n$$

$$J_{d=\frac{MD_{Kn}}{10000\,RT}\nabla P}$$

$$D_{kn} = \frac{d_{pore}}{3}\sqrt{8RT/\pi M}$$

$$D_{kn} = Knudsen\ diffusion\ coefficient$$

The mass flow of unit area of molecular free flow regime is:

$$J_d = \frac{k_{d_{free}}\,\rho\nabla p}{\mu}$$

$$J_d = \frac{2rm}{3\times1000\,RT}\nabla p(8RT/\pi M)^{0.5}$$

Nano Pore Multi Scale Model:

Nanopore multi scale model is the flow model the including slip flow, transition flow, Knudsen diffusion and continuous flow in nano pore. The flow characteristics for different pore scales vary on basis of Knudsen number such as the smaller scales in molecular diffusion, larger scales in case of transition flow, some larger scales in case of slip flow and continual flow with largest scale. These flows could exist at same time in shale gas reservoirs.

All stages of flow should be taken in consideration and finally the mass flow equation by considering continuous flow, slip flow, transition flow and transition flow is:

$$J = J_a + J_{slip} + J_T + J_d$$

$$J = \frac{r \times r\,\rho_{avg}}{8\mu}\nabla p\,\frac{2+\left(\frac{Kn}{4.5}\right)^4}{1+\left(\frac{Kn}{4.5}\right)^4}\,F\frac{r^2\rho_{avg}}{8\mu}\nabla p + \frac{1+\left(\frac{Kn}{4.5}\right)^4}{1+\left(\frac{Kn}{4.5}\right)^4} + \frac{2rM}{3 \times 10^3 RT}\nabla p\sqrt{\left(\frac{8RT}{\pi M}\right)}$$

$$J = \left[\left[\frac{2+\left(\frac{Kn}{4.5}\right)^4}{1+\left(\frac{Kn}{4.5}\right)^4} \times F\right]\frac{r^2\rho_{avg}}{8\mu} + \frac{1+2\left(\frac{Kn}{4.5}\right)^4}{1+\left(\frac{Kn}{4.5}\right)^4} \times \frac{2rM}{3 \times 10^3 RT}\sqrt{\frac{8RT}{\pi M}}\right]\frac{p_{1-p_2}}{L}$$

The apparent permeability derived by considering transition flow, slip flow, the molecular diffusion and continuous flow. The equation of apparent permeability based on Knudsen number.

$$K_{app} = \left[\frac{r^2}{8} + \left(\frac{2+\left(\frac{Kn}{4.5}\right)^4}{1+\left(\frac{Kn}{4.5}\right)^4}\right) + F\frac{r^2}{8} + \left(\frac{1+2\left(\frac{Kn}{4.5}\right)^4}{1+\left(\frac{Kn}{4.5}\right)^4}\right) + \frac{2\mu rM}{3 \times 10^3 RT\rho_{avg}}\sqrt{\frac{8RT}{\pi M}}\right]$$

The Darcy law can account for continuous flow and its permeability such that

$K_D = \frac{r^2}{8}$

The ratio of apparent permeability and Darcy permeability is

$$K_{app}/k_D = \left[1 + \left(\frac{2+\left(\frac{Kn}{4.5}\right)^4}{1+\left(\frac{Kn}{4.5}\right)^4}\right) \times F + \left(\frac{1+2\left(\frac{Kn}{4.5}\right)^4}{1+\left(\frac{Kn}{4.5}\right)^4}\right) \times \frac{2\mu rM}{3 \times 10^3 RT\rho_{avg}}\frac{8}{r}\sqrt{8RT/\pi M}\right]$$

CONCLUSION:

By reviewing many papers, we have studied the importance of relative permeability in production of gas form shale reservoirs. In future we are going to incorporate this relative

Permeability term in our model, where we are developing a set of PDE equations which represents the flow behavior of gas in shale reservoirs i.e from matrix to hydraulic fracture and from hydraulic fracture to well bore.

NOMENCLATURE:

A = cross-sectional area, m2

c = concentration, mol

c_g = gas compressibility.

D = Knudsen diffusion, m2/s

F = theoretical dimensionless coefficient

J = mass flux, kg/s/m2;

k = permeability, m2

K_D = Darcy permeability.

K_{app} = apparent permeability.

L = pore length, m

M = molar mass, kg/kmol

p = pressure, kPa

q = flow rate, m3/s

r = pore radius,

G_L = Langumair's volume, NTP.

R = gas constant, J/mol/K

Z = gas compressibility factor

t = time, s

T = temperature, K

u = velocity, m/s
U = advective velocity, m/s
SV = surface area to volume

Greek letters:
α = tangential momentum accommodation coefficient, fraction
k = desorption constant, 1/s
μ = viscosity, Pa.s
r = density, kg/m3

Subscript:

a = advective
app = apparent
avg= average
D = diffusive
K = Knudsen

REFERENCES:

1. FOLK, R.L., Petrology of SedimentaryRocks;Hemphill Publishing Company, Austin, TX, 1974.
2. JAVADPOUR, F., FISHER, D. and UNSWORTH, M., Nanoscale Gas Flow in Shale Sediments; Journal of Canadian Petroleum Tech- nology, Vol. 46, No. 10, pp. 55-61, October 2007.
3. KATSUBE, T.J., Shale Permeability and Pore-Structure Evolution Characteristics; Current Research 2000-E15, Geological Survey of Canada, Ottawa, ON, 2000.
4. Jones, F.O. and Owens, W.W.1980. A Laboratory Study of Low-Perme ability Gas Sands. Journal of Petroleum Technology,1631–1640.PaperSPE7541-PAdoi:10.2118/7551-PA.
5. Sampath, C.W., Keighin, K. 1982. Factors affecting gasslippage in tightsand stones. Paper SPE9872. J. Petrol. Technol, **34,** 2715–2720. doi:10.2118/9872-PA
6. Florence, F.A., Rushing, J.A., Newsham, K.E. and Blasingame, T.A. 2007. Improved Perme ability Prediction Relations for Low-Perme ability Sands. Paper SPE107954 presentedat SPE Rocky Mountain Oil & Gas Technology Symposiumheld at Denver, Colorado,16–18 Apr. doi: 10.2118/107954-MS.
7. Klinkenberg, L. J. 1941.The Permeability of Porous Mediato Liquidand Gases. APIDrilling and Production Practicep. 200–213.
8. Javadpour,F.,Fisher,D.,andUnsworth,M.2007.Nanoscale Gas Flowin Shale Gas Sediments. Journal of Canadian Petroleum Technology, **46**(10),55–61.doi:10.2118/10.2118/07–10-06.
9. Javadpour,F.2009.Nanopores and Apparent Permeability of Gas Flow in Mudrocks (Shales and Siltstone).Journal of Canadian Petroleum Technology, **48**(8), 16–21.doi:10.2118/09–08-16-DA.
10. LiZ, LiZ. Dynamic characteristics of shalegas flowinna no scalepores[J].The naturalgasindustry,2012,**32**(4):50–53.
11. Najeeb Alharthy, Mohammed Al Kobaisi and, Mehmet A.Torcuk,etal.Physics and Modeling of Gas Flowin Shale Reservoirs.This paper was prepared for presentationat the Abu Dhabi International Petroleum Exhibition & Conference heldin Abu Dhabi,UAE,11–14November 2012.
12. Loucks, R., Reed, R., Ruppel ,S., and Hammes, U.2012. Spectrum of poretypesandnet works in mudrocks and adescriptive classification formatrix-relatedmudrockspores.The American Association of Petroleum GeologistsBulletin,v.**96,**No.6,pp.1071–1098.
13. Choquette,P.W.,andL.C.Pray,1970.Geologicnomenclatureandclassificationofporosityin sedimentarycarbonates.AmericanAssociationofPetroelumGeologistsBulletin,v.**54,**pp.207–244.
14. BIRD, R.B., STEWART, W.E. and LIGHTFOOT, E.N., Transport Phenomena; Second Edition, John Wiley & Sons, Inc., Hoboken, NJ, 2007.
15. ROY, S., RAJU, R., CHUANG, H.F., CRUDEN, B.A. and MEYY- APPAN, M., Modeling Gas Flow through Microchannels and Nanopores; Journal of Applied Physics, Vol. 93, No. 8, pp. 4870- 4879, 2003.
16. HORNYAK, G.L., TIBBALS, H.F., DUTTA, J. and MOORE, J.J., Introduction to Nanoscience and Nanotechnology; CRC Press, Boca Raton, FL, 2008.
17. COOPER, S.M., CRUDEN, B.A., MEYYAPPAN, M., RAJU, R. and ROY, S., Gas Transport Characteristics through a Carbon Nanotu- bule; Nano Letters, Vol. 4, No. 2, pp. 377-381, December 2003.
18. KARNIADAKIS, G., BESKOK, A. and ALURU, N., Micro- flows and Nanoflows: Fundamentals and Simulation; Springer Science+Business Media, Inc., New York, NY, 2005.