Sorption Time and its relationship with Permeability in CBM Assessment using Geo-Modelling & Reservoir Simulation

Bibhu Parida, Debabrata Banerjee, Jagadish Chand* *Reliance Industries Ltd, India*

bibhu.parida@ril.com

Keywords

CBM, Coal Bed Methane, Sorption Time, Geomodelling, Reservoir Modelling, Cleat Permeability

Summary

Sorption or desorption time is a measure of diffusivity, defined as the length of time required for 63% of the gas to be desorbed from the coal sample. Varying sorption time will not affect the ultimate gas recovery but will shift the time for achieving peak gas production. Sorption time determined during the gas desorption studies of coal samples from core holes were used for modeling purpose in the present exercise. This can be indirectly calculated using cleat characteristics which can be obtained from Image log or field mapping.

The objective of this work is to study the effect of sorption time on the gas production rate in coalbed methane (CBM) reservoirs. Numerical simulation is employed to investigate this phenomenon in coal seams. Vertical well with multi-layered model with varying sorption time is generated with properties similar to the Barakar formation in Sohagpur coalfield.

The results indicate that the sorption time affects the production rate in the early production phase, namely a few months to a few years depending on how slow the desorption/diffusion process is, but this depends on the magnitude of the sorption time. However, in the latter case, the effect lasts longer since the dewatering must occur first for desorption/diffusion process to start.

The multi-coal seams simulation shows that when sorption time is smaller than 5 days, the effect of sorption/diffusion phenomena on total commingled production rate is negligible. Also, if the permeability is higher, sorption time impact gets lower. For moderate to low permeability reservoirs, sorption time plays a more important role than higher permeable coal zones.

Introduction

As India is a gas deficient nation, unconventional gas resources especially Coal Bed Methane (CBM) have attracted more attention in the past few decades. The majority of the CBM resources in India are found in Eastern and central basins (Fig1).

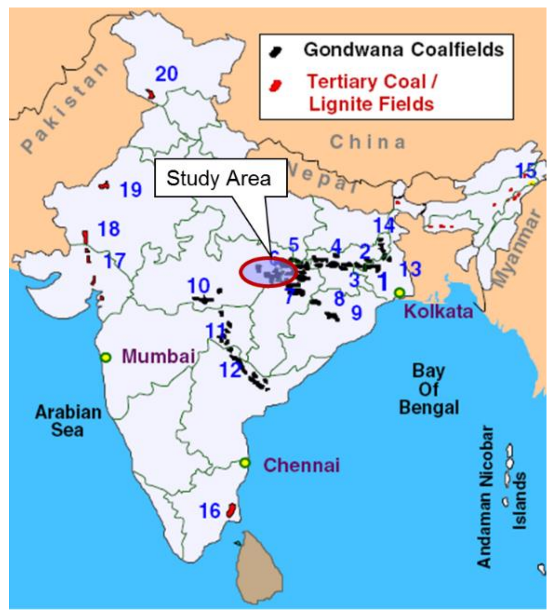

Figure 1:Major Coal basins of India including study area

Coalbed acts as both source and reservoir for methane. Methane in the coal is found largely in form of the adsorbed gas on the surface of micropores. Methane desorbs and diffuses from micropores to cleat systems; then cleat network delivers the gas to wellbore. Therefore, the dominant transport mechanism in the matrix is diffusion (Thimmons et al, 1973), whereas in the cleat system the Darcy's transport mechanism is the key player. Because a large portion of gas in coal is sorbed gas, the kinetics of sorption/diffusion process could play an important

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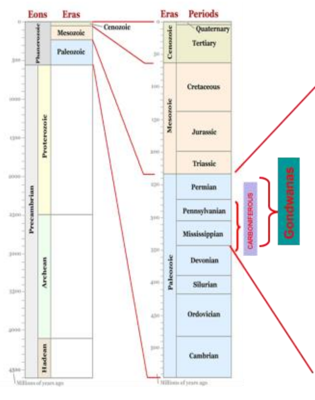
role in the gas production depending on the sorption specification of formation.

The sorption time effect on the gas and water production for a CBM reservoir with a vertical well was first reported by Remener et al (1986). Their study indicated that the speed of sorption/diffusion process can influence the gas production rates at early time.

Ziarani et al (2011) also investigated the effect of sorption time on coalbed methane recovery through numerical simulation on Canadian coals. The results indicate that the sorption time affects the production rate in the early production phase, namely a few months to a few years depending on how slow the desorption/diffusion process is, but this depends on the magnitude of the sorption time. The multi-layer study indicates that when sorption time is smaller than 10 days, the effect of sorption/diffusion phenomena on total production rate is negligible.

In this study, we have used the data from Barakar formation coals of Sohagpur Coal field which falls in central India (Fig 1). Barakar formation is a part of Gondwanas which is of Paleozoic in age and having good coal seams (Fig 2).



Age	Formation	Thickness (m)	Lithology
Upper Cretaceous to Lower Paleocene	Deccan Trap	-	Effusive and intrusive sills and dykes of dolerites and basalts
-Unconformity-			
Lower Cretaceous	Lameta Formation	60-100	Reddish and greenish sandstone, nodular limestone and calcareous clay
-Unconformity-			
Lower Jurassic to Upper Triassic	Bandhogarh Parsora	600	Quartzose sandstone with ferruginous siltstone and mottled mudstone.
Lower Triassic	Pali Formation	600	Off white to buff, coarse to pebbly, feldspathic sandstone, clasts of clay and siltstone
-Unconformity-			
Upper Permian	Raniganj Formation	500	Alternations of fine to medium grained sandstone, grey shale, carbonaceous shale and thin coals
Middle Permian	Barren Measures	200-300	Greenish white, medium grained sandstone and chocolate shale with limonitic concretions
Lower Permian	Barakar Formation	250-450	Coarse to medium grained sandstone, subordinate shale, carbonaceous shale and coal seams
Upper Carboniferous to Lower Permian	Talchir Formation	90-450	Greenish grey boulder beds, sandstone, needle shales and tillites
-Unconformity-			
Pre-Cambrian	Basement	-	Granites and gneisses

Figure 2: Generalized stratigraphy of Sohagpur Basin

Along with the study of sorption time with production rate and estimated ultimate recovery (EUR), we have tried to integrate the most important reservoir parameter for CBM flow which is permeability. So, the effect of sorption time on production with varying permeability is also modelled in this work.

Theory

The gas transport from the coal matrix to the cleat is controlled by gas diffusion. Gas flow from the matrix by diffusion is modeled with the following Fick's equation:

$$q_m = \sigma D (C_m - C_{equilibrium}) \qquad \text{(Eq 1)}$$

where:

q_m = Gas production rate from the matrix

σ = Coal matrix shape factor

D = Diffusion coefficient

C_m = Matrix gas concentration

$C_{equilibrium}$ = Equilibrium gas concentration at matrix/cleat boundary

The shape factor and diffusion coefficient are required inputs to calculate the gas flow rate from the matrix using this equation. However, it is common to estimate the diffusivity process using sorption or desorption time, which is the time required to desorb 63.2% of the initial gas volume during a whole core desorption test. The sorption time can then be related to the shape factor and diffusion coefficient using the following equation:

$$\tau = \frac{1}{\sigma D} \qquad \text{(Eq 2)}$$

Where:

τ = Sorption or Desorption time

Sorption time simplifies the equation 2 because it requires only one rock property estimate (desorption time) rather than two (shape factor and diffusivity coefficient).

$$q_m = \frac{1}{\tau}(C_m - C_{equilibrium}) \qquad \text{(Eq 3)}$$

Hence sorption time estimated during desorption test is important and is an important input in the prepared geomodel as it suffices the need for two important parameters which are difficult to measure.

Shape factor can also be calculated indirectly using cleat characteristics like number of fractures/cleats and cleat spacing. The cleat specifications are key to the equations derived both by Kazemi (1969) and

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Warren & Root (1963). These information can be obtained from Image log (Fig 3) or field mapping.

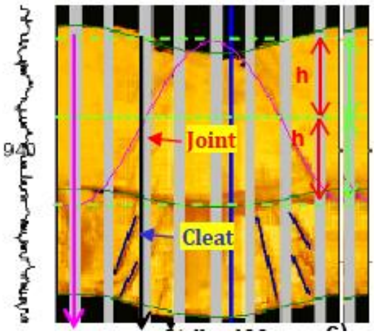

Figure 3: Image log of Coal & Cleat interpretation (after Titheridge D,, 2018)

Reservoir Modelling and Simulation

Coal bearing formations are commonly multi seams and commingling completion is a common practice in wellbores drilled in these kinds of reservoirs. Coal reservoirs are heterogeneous both vertically and horizontally. Hence, multi-layer models are employed to evaluate the effect of vertical heterogeneities which imitate closely the subsurface phenomena. For numerical simulation, dual porosity model is used which was proposed by Warren and Root (1963), and then Kazemi (1969) and are the most widely used models in CBM studies.

In this study, we examined coal seams of Barakar formation in Sohagpur basin, India. Stratigraphic correlation chart of the coal zones in Barakar is illustrated in Fig 4.

The Barakar formation belongs to the lower Permian period with average age of approx. 270 my. The major coal zones in Barakar are S-V (Top seam), S-IV, S-III & S-II (Bottom Seam) coal zones. The S-III located in the central part of Barakar formation represents most of the coal thickness and is the main target which is a laterally persistent zone.

The formation depth varies 0–800 m (more productive layers are within 300–500 m) with layers of non-marine sandstone, siltstone, coal, shale, and mudstone. This play is a medium rank coal (Sub-Bituminous A–C) with typical individual seam thickness of 2-10m at 2.0 gm/cc density cut-off. The formation is normal pressured (0.42 to 0.46 psi/ft).

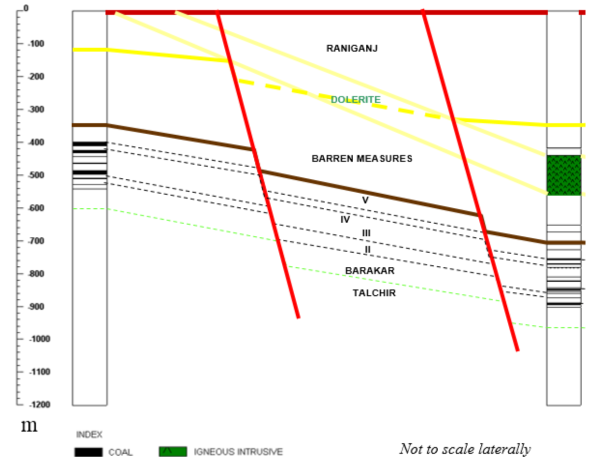

Figure 4: Generalized cross section of Sohagpur Basin with major Coal Seams of Barakar Formation

A three dimensional 160 acre spacing geo-model consisting of seven layers is built based on data. Out of seven layers four are the major persistent seams described above and three are local seams. The layers differ in initial reservoir pressure, temperature Gas content, coal density, thickness, cleat permeability and sorption time. Sorption time for all major seams were around 5days. All other information like thickness, gas content, saturation etc are kept same for all layers. A vertical well is drilled at the center of the reservoir and all layers are perforated and produced commingled (Fig 5).

To check the sensitivity, sorption times varied from 1 to 150 which are the most likely extreme ends of sorption time values in Sohagpur Barakar coals. Simulation is run using the industry accepted unconventional simulator Comet3 using dual porosity and single permeability model.

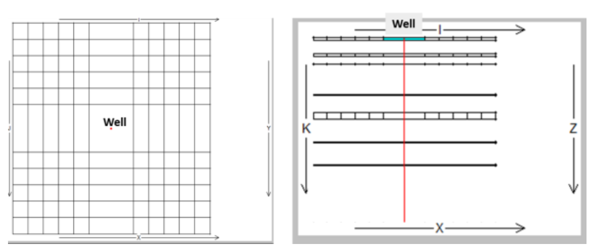

Figure 5: Map & Cross View of the Geo-Model Used for Reservoir Simulation

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Results

The modeled single well run successfully and estimated production profile extracted. Though the simulation is run for 40 years, for clarity the graph Fig. 6 & 7 shows first 40 months where it compares monthly average gas production rate in SCMD for every sorption time sensitivity.
The gas production rate with various sorption times is depicted in Fig. 6.

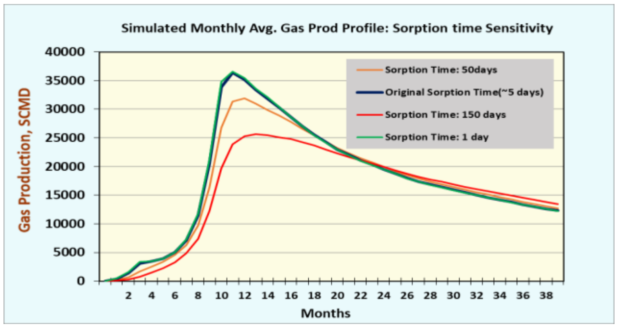

Figure 6: Gas production trend with different sorption times

The result shows that, the sorption time has the largest impact on the gas rate in the first 10-18 months of production when desorption/diffusion process varies from very slow to very fast (high values of sorption time to low values of sorption time). The effect of sorption time on the gas rate converges after about 20-24 months of production. For smaller values of sorption time ~5 days, the effect is almost negligible. The difference is getting wider when sorption time becomes more than 100 days as we can see from the 150 days production profile.
We tried to find the relationship of permeability to the changes in sorption time. For that we used exactly the same model and changed only the permeability values. The k values of the thickest and permeable zones are reduced from 50-100 mD to 20 mD. The results are depicted in fig 7.

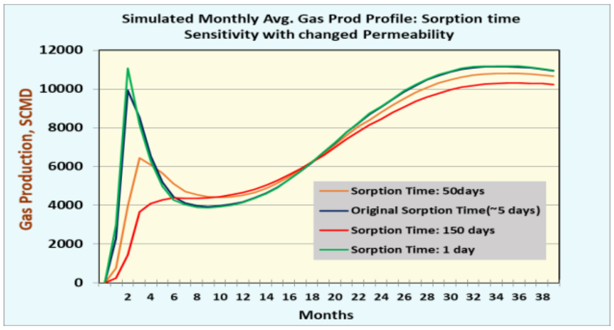

Figure 7: Estimated gas profiles for different sorption time with lowered k values

The results indicate a slight difference interpretation that the previous one. The peak production and shape of curves indicate a moderate to low permeability regime. In this lower permeability scenario, there is a difference of approx. 10% in the peak production when we compare sorption time of 5 days to 1 day. Also the peak production at 50 sorption days and 150 sorption days are much lower in percentage terms than the higher permeability case. The initial peaks in this low perm case are due to the effect of hydro fracturing induced higher conductivity in the near wellbore area.

Conclusions

This simulation study shows how erroneous the results of a reservoir model could be if one uses the model without considering impact of sorption time and relationship of perm with this during the early production data. The magnitude of this error could be as high as 10-30% at early times which is even higher if we consider peak gas rate (20 to 50%). The value of this error depends on many parameters including but not limited to:

- Desorption/diffusion characteristics of coal seam (how slow the process is).
- Permeability (higher permeability reduces the impact of higher sorption time)

Desorption/diffusion characteristics of coal seam appear to have a significant influence on the gas rate in the first few months and in low permeability cases even the first few years of production. The sorption time parameter controls how fast matrix can feed gas to fractures and therefore affects gas production rates. In other words, the diffusional flow of gas molecules through micropores plays a very important role in the

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dynamics of production until a steady-state diffusion flow is reached. The time needed to reach a steady-steady state diffusion flow can be affected by many factors including diffusion coefficient and geometry of matrix-fracture i.e. shape factor.

Therefore, the following conclusion can be drawn from this study:

1. Sorption time plays a critical role during early production. This effect starts from the beginning of production and ends after a period ranging from a couple of months to a couple of years depending on the magnitude of sorption time.
2. Hence sorption time estimated during desorption test is important and is an important input in the prepared geomodel as it suffices the need for two important parameters which are difficult to measure. Shape factor can also be calculated indirectly using cleat characteristics like number of fractures/cleats and cleat spacing.
3. The smaller the sorption time, the sooner this steady-state behavior is reached. In fact, a sorption time of a few days is shown to have no significant effect on gas rates.
4. Also if the permeability is higher, sorption time impact gets lower. For moderate to low k reservoirs, sorption time plays a more important role than higher k coal zones.
5. Lesser impact due to low sorption time or higher permeability is because for smaller sorption times (larger diffusion coefficients) or higher permeability, the transient period of flow of matrix-fracture is much shorter.

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