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Evaluation of Production from Multi-porosity Unconventional Reservoirs

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Abstract
A dual porosity or a dual permeability model is often used to describe a typical shale gas reservoir. Characterization of such extremely low permeability, organic rich, fractured reservoirs using these models does not aptly capture the physics and complexities of gas storage and flow through their nano-pores. In this paper, quad porosity system have been defined as porosity in organic matrix, inorganic matrix, micro fractures and macro fractures thereby providing a deeper insight into understanding these unconventional reservoirs. Further, the effect that these nano-pores spaces have on the ultimate recovery, are correctly defined by incorporating processes like diffusion, desorption and transport through natural and hydraulic fractures. This work utilizes a fracture-completed horizontal well in different configurations of quad-porosity shale gas reservoir models to assess the effect of gas flow and storage in these systems on production parameters. Simulations are runs to understand the impact of this detailed characterization on well performance. Additionally, this work also investigates the dependency of stress on these quad-porosity systems, as stress acting on the matrix and fractures play a significant role in porosity and permeability alteration. Results indicate that a considerable difference in well productivity and pressure transient is observed when reservoirs are modelled as quad-porosity systems. Also, they emphasize on the fact that correct description of these reservoirs is critical for the assessment of their production potential and further for forecasting the corresponding economic scenarios.

Introduction
In recent years it has been proven that shale reservoirs have been among the major resources for producing fossil fuels and commercial production from such reservoirs is based on technologies such as multi-fractured well completion and horizontal drilling. Reservoir simulation of unconventional reservoirs has provided an approach to study the various aspects of reservoir driving mechanisms, characterize them in a better manner and improve their production forecast. Geological studies of shale reservoirs depict that they are complex systems comprised of hydraulically induced fractures, natural fractures and matrix. Success in unconventional gas reservoirs can be attributed to its high shale quality and evaluation of production technology. The high shale gas quality depends upon the basin’s favourable gas content, depth, thickness, pore network and high brittleness. The mechanisms of fluid flow and pore network are complex and challenging, and are significantly different from conventional gas bearing formations. In conventional reservoirs, hydrocarbons migrate from source rock to reservoir rock while shale reservoirs act both as a source as well as reservoir rock. The storage mechanism in shale gas reservoirs is much more complex than conventional ones. Storage in such reservoirs is characterized by both free and adsorbed gas. The most accurate way to define these reservoirs is to determine the pore sizes and gas flow network using mathematical and simulation models.

Background
As evidenced from previous work, most of unconventional reservoirs are simulated using single-porosity system or dual-porosity systems. The dual porosity model assumes the shale matrix as the storage grid and intersecting fracture network as the flow conduits that help hydrocarbon flow to the well. Shale gas reservoirs are significantly different from conventional reservoirs in terms of their characterization, their producing mechanism as well as their composition. Therefore, using conventional dual porosity system for simulating shale reservoirs would lead to an underestimation of its gas in place values as well as the cumulative gas produced (Passy et al 2010). In such shale

reservoirs, natural gas is governed by organic matter. Hence compositional variation in organic matter makes such reservoirs highly heterogeneous. (Sondergeld 2010) states that porosity that occurs within organics, pyrite and minerals are in the form of micro cracks. Therefore, advanced reservoir engineering methods are necessary to model gas flow in shale reservoirs. Conventional methods using Darcy's law underestimates actual production from shale (Lu et al 1995, Freeman et al 2010, Javadpour 2009, Shabro et al 2011, Ambrose et al 2010, Swami and Settari 2012). In order for the economical assessment of unconventional gas formations, certainty of volume of gas production takes prominence. Shale reservoirs have shown that they are complex systems composed of quartz, pyrite, clay minerals and organic matter known as Kerogen. Inside the organic matter, Kerogen is divided into two categories – porous space and Kerogen bulk. Gas is known to be stored in the nano-pores of this Kerogen as well as in a dissolved state within the Kerogen bulk. (Wang et al 2009) described Barnett shale consisting of four porosity types: non organic matrix, organic matrix, natural fractures and hydraulically induced fracture and this concept has drawn a lot of attention by other researchers worldwide. (Yan et al 2013) further described shale reservoirs as a sub-division of organic matrix into a porosity type which either has vugs or don't. Others (Apaydine et al 2012) subdivided natural fractures into micro and macro categories. A triple-porosity model is presented for shale gas reservoir which consists of matrix, less permeable micro structure and more permeable macro structure(Al-Ahmadi et al 2011). (B. Haghshenas et al 2013) presented a conceptual model with multi-porosity, multi-permeability for fluid flow in shale play. They considered 3 different configurations for fluid flow through triple-porosity system (organic matter, inorganic matter and natural fractures).They further proposed a triple-porosity system to capture a more realistic shale structure. Results indicated that the non-Darcy flow component has a significant effect on production behaviour in shale gas reservoirs.

Simulation

It is believed that the gas in a shale reservoir is stored both as free and adsorbed gas. It is seen that shale reservoirs consist of a combination of organic matter, inorganic matter, natural fractures, and hydraulic fractures – if induced. Gas occupies in the form of adsorbed as well as dissolved state within the Kerogen, along with being present within the natural fractures and nano pores. A sequence of how gas production takes place from these complex reservoirs is given by closely related work (Javadpour, 2009). Due to pressure drawdown, gas flow is initiated, which is followed by gas desorption, and the last process to follow is gas diffusion. Work was performed (Wang et al, 2009) which reported the presence of porous networks within the organic material of the shale reservoirs. In this work, to study the effect of multiple porosity system on both the gas in place as well as well deliverability, hydraulic (macro) fractures have been added to the shale model already defined by B.Haghshenas (2013). This alteration in the model leads to the reservoir consisting of four porosity types. Additionally, the effect of adsorption / desorption and diffusion in such reservoirs have been accounted for, in the simulations. Further, permeability is varied inside the created fractures in the model, to account for the effect of stress acting on them. This paper discusses the effect of stress induced permeability change in both quad-porosity and dual porosity systems along with a sensitivity study on critical parameters. This is done by running accurate reservoir simulation models which represent a realistic reservoir.

Quad-porosity model description

Quad-porosity models are constructed in a commercially available simulator,and the different porosity types have been defined as porosity in organic matrix, inorganic matrix, micro (natural) fracture and macro (induced) fractures. These systems are discretized using the gridding tool of simulator, and the individual porosity types are defined by four individual rock types in different regions of reservoir. In the inorganic porosity system, it is assumed that gas flow takes place only in accordance with Darcy law, whereas the flow in the organic matrix model is influenced by gas adsorption, diffusion and slippage. In this work, Langmuir isotherm is used for defining the adsorbed gas in the organic part. The equation for the Langmuir equation is given as:

$$\mathrm{V_a} = {}^{\mathrm{V_L P}}\!/_{\mathrm{P} + \mathrm{P_L}} \tag{1}$$

Where $\mathrm{V_a}$ is the amount of gas adsorbed by on ton of rock, $\frac{\mathrm{lbmole}}{\mathrm{ton}}$; $\mathrm{V_L}$ is the Langmuir volume which represents the maximum adsorption capacity, $\frac{\mathrm{lbmole}}{\mathrm{ton}}$; $\mathrm{P_L}$ is the Langmuir pressure which is pressure at $\frac{\mathrm{V_L}}{2}$ and affects the curvature of the isotherm psi. (Javadpour et al 2007, Javadpour 2009) presented a mechanism which can be applied across the entire Knudson number spectrum. They created a multiplication factor for Darcy velocity which has two terms, one for Knudson diffusion and one for slip flow. The corrected equation is as follows:

$$K_a/K_D = F_K + F_S \qquad (2)$$

Where F_K is the factor due to Knudson diffusion and F_S is the factor due to slip flow

$$F_K = C_1 \frac{\mu M D_K}{RT\rho}\frac{8}{r^2} \qquad (3)$$

Where C_1 is a conversion factor, and ρ is the gas density.

$$F_S = 1 + C_2\left[\left(\frac{8\pi RT}{M}\right)^{0.5}\frac{\mu}{pr}\left(\frac{2}{\alpha}-1\right)\right] \qquad (4)$$

Where C_2 is another conversion factor, and α is the tangential momentum accommodation coefficient. The value of α varies theoretically from 0 to1, depending on the wall surface smoothness, the gas type, temperature, and pressure. Javadpour suggested the value of α= 0.8. The Knudson diffusion factor D_K is defined as:

$$D_K = \frac{2r}{3}\left(\frac{8RT}{\pi M}\right)^{0.5} \qquad (5)$$

Diffusion flow becomes a function of pressure gradient instead of compositional gradient by the assumption of single-phase flow. The velocity in the x- direction due to single component diffusion can be expressed as:

$$v_D = \frac{M_g D_K}{\rho_g}\frac{\partial c}{\partial M} \qquad (6)$$

The molar concentration for single-phase flow can be expressed as:

$$C = \frac{\rho_g}{M_g} = \frac{p}{ZRT} \qquad (7)$$

Assuming Z=1

$$v_D = \frac{M_g D_K}{\rho_g RT}\frac{\partial p}{\partial x} \qquad (8)$$

The model in this work involves applying a constantly decreasing permeability to the created hydraulic fractures. The decrease of permeability in the placed fractures is simulated using an exponential approach. Simulations were run by varying multiple parameters, to observe the impact of this decrease on the overall productivity of the well. These declining trends were chosen because they are convenient for incorporating in a shale gas fractured horizontal well model, as well as due to availability of data. For the assessment of this impact of fracture permeability reduction with drawdown, accurate reservoir simulation models which represent a realistic reservoir were built and run. The model included a single horizontal producer and four equally spaced hydraulic fractures in the reservoir. Hydraulic fractures are placed 700 ft apart and are generated in a transverse direction, perpendicular to the horizontal wellbore. The model used here is based on standard assumptions of a common fractured well which produces from a shale gas reservoir. In this model, secondary fractures are considered to be orthogonal to the placed hydraulic fractures. The simulations were run at a constant BHP of 1000 psi for 30 years, and the reservoir thickness is considered to be 300 ft.

Results and Discussion

This section provides the simulation runs which were done to compare the results between quad and dual porosity systems, along with sensitivity analyses with different parameters such as bottom-hole pressure, Langmuir isotherm, fracture half-length, secondary fracture spacing and permeability. For the base case runs, the reservoir permeability was assumed to be 0.0001 mD, with 3.6% porosity. The water saturation was considered to be 30%, with the initial reservoir pressure at 3600 psi. The gas gravity was 0.6, and the reservoir temperature was considered 106 degree F. It should be noted that the effect of stress leading to a degradation of permeability within the placed hydraulic fractures has been incorporated within the model.

Bottom-hole pressure: The simulations were run with varying bottom-hole pressure, for a reservoir with 0.0001 mD permeability. The fracture half-length was kept at 750 ft, and fractures were placed 700 ft apart. Figure 1shows the rate and 30-year cumulative gas production when the bottom-hole pressure was varied form 1000 psi to 500 psi. With a higher drawdown, the initial rate is seen to spike for both the dual and the quad porosity systems. However, after the initial decline, it is seen that the difference in the production rates reduces, when the well starts flowing in pseudo-steady state condition. Also, it can be seen from the rate plot that the difference between the dual and quad porosity rate values goes on decreasing, as there is not much of a difference between individual dual porosity curves. It can also be seen from the cumulative production plot that the difference between the dual and the quad porosity curves stabilizes at higher times. This could be attributed to the fact the in a quad porosity system, contribution from diffusion-based flow comes at late times.

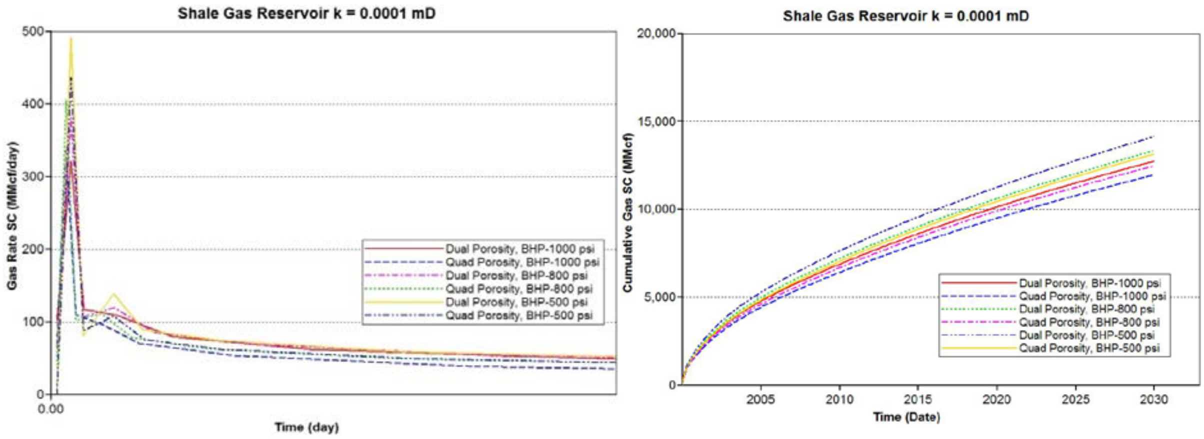

Figure 1: Bottom-hole pressure

Half-Length: Both the dual as well as the quad porosity models were run by varying the half-length of the created hydraulic fractures, which was varied from 250 ft to 750 ft, with an intermediate run of 500 ft. It can be seen from the figure that the relative gain the cumulative production for the dual porosity system is significantly higher than that for the quad porosity system. As shown in Figure2, Dual porosity systems exhibit significantly different signatures of initial production rates, whereas the quad porosity systems follow the same trend. Higher recoveries from quad porosity systems could be because of the high gas in place values, with the gas in organic matter being accounted for.

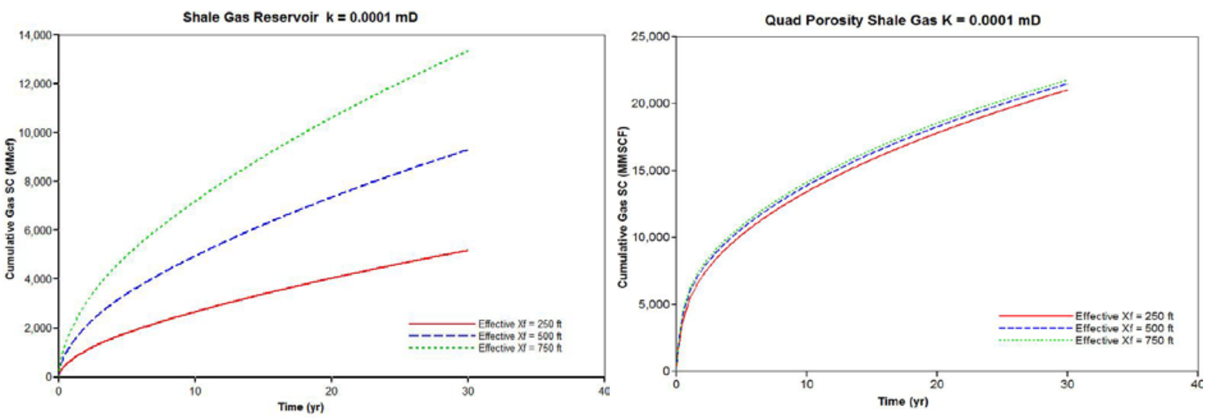

Figure 2: Half-length

Reservoir Permeability: Reservoir permeability in shale reservoirs are significantly less, resulting in ultimate recoveries spanning across many decades. Imposing a higher drawdown on wells completed in such reservoirs can only accelerate the recovery to a certain extent. Figure 3 shows the results when runs were done to observe the impact of the reservoir permeability on the ultimate recovery from dual and quad porosity reservoirs. It can be seen from the Figure that as the permeability goes on increasing, the cumulative production goes on increasing. However, it needs to be noted that the percentage difference between a dual and quad porosity cumulative production values goes on increasing. This is due to the fact that the production of gas from a quad porosity system is a slow process.

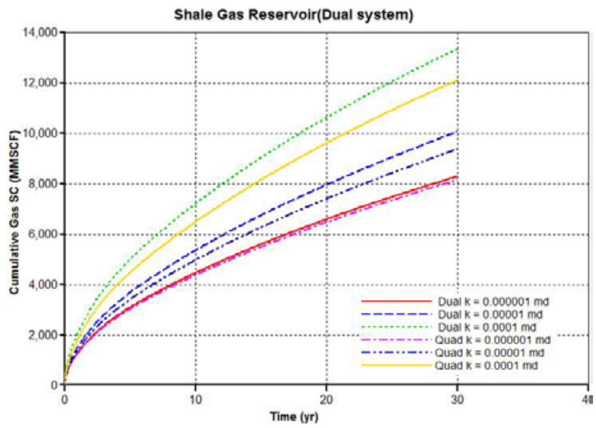

Figure 3: Reservoir permeability

Langmuir Isotherm: Within the shale gas matrix, the organic matter is assumed to be the main gas bearing porosity system with the gas flow being governed by both Darcy's law and diffusion. The inorganic porosity is assumed to be saturated with water and the flow in this sub-system is due to gas adsorption, diffusion, and slippage. The Langmuir equation, which considers the adsorption mechanism to be monolayer adsorption, is widely used to describe adsorption / desorption in unconventional reservoirs. In this work, the Langmuir isotherm is used for defining the adsorbed gas in the organic part of the matrix. The effect of adsorbed gas on the quad porosity system was investigated, and it was found that altough the phenomenon is an important one, its impact on the total cumulative gas recovered is not significant, as seen in Figure 4.

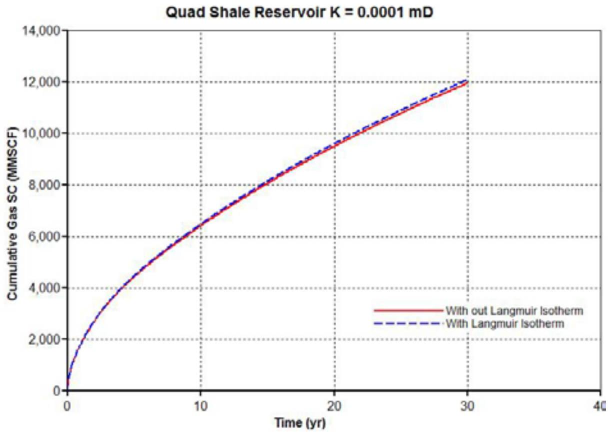

Figure 4: Langmuir isotherm

Secondary Fracture Spacing:The denser the network of secondary or natural fractures, the better the

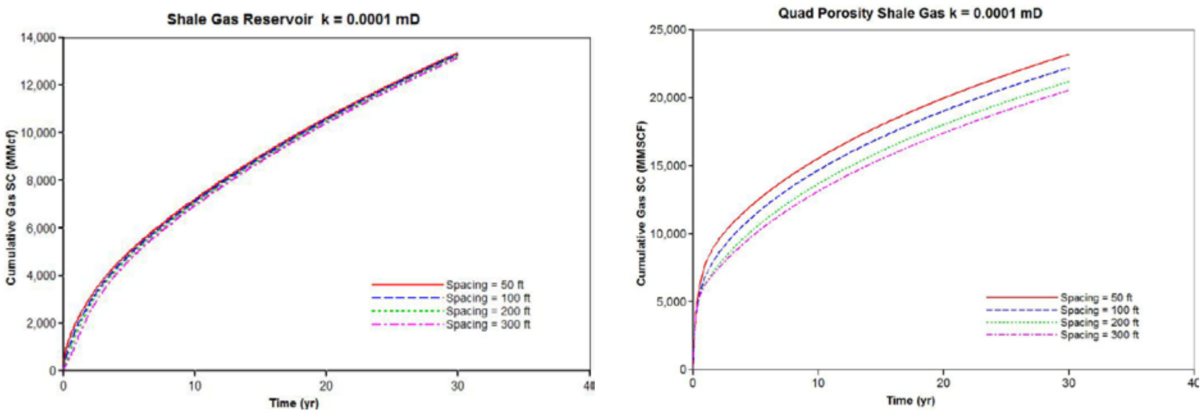

Figure 5: Secondary fracture spacing

induced hydraulic fractures will connect with them, thereby increasing the connectivity to the wellbore. In the case of dual porosity models, it was observed that there was no significant difference when the spacing was reduced. However, in the quad porosity model runs, it is seen that when the spacing is reduced, a higher cumulative production is obtained, as shown in Figure 5. A reduction in the spacing means a denser network, where chances of some of the secondary fractures also getting propped are higher. This is due to the combined effect of propped secondary fractures coupled with the gas stored in the additional porosity systems of the reservoir.

Conclusions

Based on the simulation results and the parametric investigations performed in this study, following conclusions are provided:

1. The simulation models point to the fact that gas stored in the individual porosity types is critical, which is justified from the increased oil in place observed for the quad systems.
2. When the bottom-hole pressure is varied, a significant difference is seen in the initial rates, which reduces over a period of time.
3. Impact of changing half-length in a quad porosity system is not as significant as varying it in a dual porosity system, although the cumulative in a quad system is higher.

4. The impact of the adsorbed gas on the organic part of the matrix was investigated and it was seen that the impact is not critical, although a minor difference in cumulative production was seen.
5. Secondary fracture spacing significantly impacts the recovery from a quad porosity reservoir, as the much denser spaced natural fractures provide the necessary conduits for the higher volume of gas to flow towards the wellbore.

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