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Coupled fluid flow and geomechanics modeling of stress-sensitive production behavior in fractured shale gas reservoirs

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ABSTRACT

Compared with conventional reservoirs, gas flow in shale formation is affected by additional nonlinear coupled processes such as matrix/fracture deformations. We present a fully-coupled fluid flow and geomechanics model to accurately characterize the complex production behaviors of fractured shale gas reservoirs. The flow equations are discretized using a mimetic finite difference method, and poro-elasticity equations by a Galerkin finite-element approximation. A unified apparent-permeability model is implemented to quantify the combined impacts of the non-Darcy flow, adsorbed layer and pore-structure alterations on matrix permeability.

The discrete fracture-matrix (DFM) model based on a conformal unstructured grid is employed to explicitly represent fractures. The nonlinear contact problem between the two fracture surfaces is introduced to describe the fracture mechanics behavior. A splitting-node technique is used to deal with the discontinuities in the displacement field across the fracture interface. Under the effects of pressure decline and high confining stresses on the fracture faces, proppant compaction and embedment may occur, causing fracture closure and thus substantial production loss. Hence we also develop a comprehensive proppant-fracture model which is based on the theories of elasto-plastic contact mechanics, to capture the complex interactions between proppant and fracture.

The multiphysics numerical model enables us to investigate which factors have the most influential effect on the gas recovery of shale formations. High fidelity numerical solutions are provided to characterize the rate-transient signatures in the presence of the different flow and geomechanical mechanisms.

1. Introduction

Due to the rapid depletion in conventional resources of natural gas, unconventional reserves such as shale gas reservoirs have become more and more important for the energy industry in North American and have gradually turned into a major supplier of world energy demand in recent years. Shale gas production can be economically viable if sufficient stimulation of ultra-tight formation is achieved through the technologies of horizontal drilling and hydraulic fracturing. In order to obtain optimal management plans for shale gas reservoirs, there is considerable interest in numerical modeling approaches which can adequately characterize the complicated production behaviors.[1] Compared with conventional reservoirs, gas flow in shale formation is affected by additional nonlinear coupled processes including gas adsorption, low-permeability non-Darcy flow and matrix/fracture deformations.[2–5]

Darcy's law, which describes viscous flow driven by pressure gradient, is applicable to porous media where continuum theory holds and fluid velocity could be approximated as zero at the pore wall.[6] However, the fluid-continuum theory is no longer valid for shale reservoirs with pore radius in the range of nanometers.[7] Dynamic apparent permeability models are extensively employed to reflect the flow regimes associated with the non-Darcy effect.[1] The adsorbed gas layer on the pore surface occupies the pore space, resulting in the variations of the gas apparent permeability.[8,9]

In addition, stress-sensitivity is another active phenomenon in shale gas reservoirs. During reservoir depressurization, the pore pressure decline leads to a rise in the effective stress which, subsequently compacts pore-structure geometry and reduces formation porosity and intrinsic permeability.[10] In the meantime, gas desorption triggers matrix shrinkage, whose effect is contrary to the pore pressure decrease.[11,12] Consequently, the net change in porosity and permeability accompanying gas extraction is controlled by the several competing processes.[13] The nonlinear and stress-sensitive flow phenomena can be further aggravated by the generation of complex fracture network with non-ideal geometries after the fracturing treatment. It has been reported that the sharp decline of the gas rate within the first few months of production is one of the distinguishable features exhibited by the

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fractured stimulated wells.[14] The stimulation process involves injecting high-pressure fracturing fluid, together with proppants which are usually sand or ceramic particles, into shale reservoir to break down the rock. Proppants play the role of keeping the fracture open after pumping stops and fracturing fluid flows back to the surface.[15] The proppant layers filling the fracture channels can create highly conductive flow paths for gas production.[16] Under the effects of pressure decline and high confining stresses on the fracture faces, proppant compaction, embedment into shale rock, and even crushing may occur, causing fracture closure and thus substantial production loss. Several studies have proposed the purely elastic models for the contacts between proppant and fracture.[16–19] Hertzian theory is widely applied for purely elastic contacts,[20] but in most cases there are plastically deforming behaviors which extremely complicate the contact force-displacement relationship.[21] Under high compressive stress, the failure of shale rock can be initiated. Hertzian theory does not work properly when the vertical displacement is large relative to the radius of proppant sphere. Therefore in this work we develop a comprehensive proppant-fracture model which is based on the theories of elasto-plastic contact mechanics, to accurately capture the proppant embedment phenomena.

A fully coupled fluid flow and geomechanics model is developed to simulate the stress field and gas production in fractured shale reservoirs. A unified model for gas flow in organic nanopores is implemented, accounting for the coupling mechanisms of the non-Darcy flow regimes, adsorption layer and stress dependence. The flow equations are discretized using a mimetic finite difference method, and the poro-elasticity equations by a Galerkin finite-element approximation. The discrete fracture-matrix (DFM) model based on a conformal unstructured grid is employed to represent a fracture as the interface between two neighboring cells. The nonlinear contact problem between the two fracture planes is introduced to describe the fracture mechanics behavior. A splitting nodes technique is used such that each node along the fracture interface is assigned to double nodes with the same coordinates, for overcoming the presence of explicit discontinuities in the fractured domain.[22]

The developed multiphysics simulator allows us to examine which factors have the most significant impact on the gas recovery of shale formations. High fidelity numerical solutions are provided to characterize the rate-transient signatures in the presence of the different flow and geomechanical mechanisms.

2. Gas flow and storage in deforming fractured shale

Shale gas sediments contain high concentration of organic material that are characterized by pores having sizes in the range from 1 to 100 nm. Because of the tiny pore space (nanometer scale), the internal surface area associated with the organic nanopores is very large. The organic material also exhibits greater adsorption potential for the hydrocarbon fluids compared to the conventional reservoirs. Therefore the organic pores are the ideal places for massively trapping gas in the adsorbed and dissolved states. Release of adsorbed gas has to be incorporated into a numerical model for accurately predicting reservoir performance.[23]

As the geometric-length scale of the shale pores is comparable to the mean free path of the gas molecules, gas rarefaction effects including velocity slippage and Knudsen diffusion become significant, due to the strong rock-fluid interactions. This leads to deviation from continuum flow, and classical Darcy's equation could not adequately describe the relevant non-viscous gas flow regimes.[6] To quantify this type of non-Darcy mechanisms, the apparent permeability corrections are usually integrated into the standard Darcy's equation. The apparent gas permeability is a function of Knudsen number, which is the ratio of the molecular mean free path to the hydraulic radius of the pores, and can be applied to characterize the various flow regimes. In addition, gas flow is affected by the adsorbed layer within the flow channels. The adsorbed molecules can potentially occupy much of the area available to flow. The reduction of the effective hydraulic radius will impact the non-Darcy gas flow, and thus should be considered in calculating the apparent permeability of the organic pores.[24]

In conventional reservoirs, the stress-sensitivity of rock porosity and permeability generally has insignificant effects and is neglected in numerical simulation most of the time. However, for shale reservoirs, the ultra-low permeability of rock and abnormally high pore pressure can result in a remarkable impact of rock deformation, which needs to be properly taken into account.[25] During gas depletion, the reduction of pore pressure causes a rise in the effective stress which, in turn compacts the reservoir and reduces its porosity and intrinsic permeability.[26] Meanwhile, gas desorption induces matrix shrinkage and retards the influences of the effective stress increase on pore properties.[13] The net change in gas permeability is thus controlled by the competitive effects of declining pore pressure and sorption-induced matrix deformation. For dual-porosity systems, the pressure decline will cause fracture closure and the corresponding reduction in fracture conductivity.[27] The matrix shrinkage may widen fracture aperture, leading to conductivity enhancement.

In this work, a unified apparent-permeability model is implemented to accurately capture the combined impacts of the non-Darcy flow, variations of the adsorbed layer and pore-structure alterations on matrix permeability.

2.1. Desorption

It has been shown that shale formation contains the organic-inorganic configuration: tiny organic kerogen is scattered through predominantly inorganic matters.[28] Here the mass transfers from the adsorbed and free phase in organic nanopores are treated as a single source term which feeds the inorganic pore system. The source feeding behavior is approximated by the Langmuir isotherm model.[29] The molar quantity of gas molecules adsorbed on the pore wall of organic material in shale is:[1]

$$m_g = \rho_R \rho_{gs} V_E \tag{1}$$

The standard volume of gas adsorbed per unit rock mass can be expressed as:

$$V_E = \frac{pV_L}{p + P_L} \tag{2}$$

where p is gas pressure; V_L is the Langmuir volume (the maximum adsorption capacity at a given temperature); P_L is the Langmuir pressure (the pressure at which the adsorbed gas content is equal to $V_L/2$); ρ_R is the rock bulk density; ρ_{gs} is the gas molar density at standard condition, and V_E is the adsorption isotherm function.

2.2. Porosity and intrinsic permeability of matrix

The mechanical response of poroelastic medium is described by the Biot theory. Assuming small deformation and linear elasticity, the constitutive relationship for rock deformation and sorption is obtained by making an analogy between poroelastic dilation and thermal contraction.[25] The effective stress law is:

$$\sigma_{ij} = \sigma'_{ij} - \alpha p \delta_{ij} \tag{3}$$

where σ'_{ij} is effective stress:

$$\sigma'_{ij} = \left(K - \frac{2G}{3}\right)\varepsilon_{kk}\delta_{ij} + 2G\varepsilon_{ij} - K\varepsilon_s\delta_{ij} \tag{4}$$

where $\alpha = 1 - K/K_s$ is the Biot coefficient; G represents the shear modulus of shale; K_s is the bulk modulus of solid constituent; $K = E/3(1 - 2\nu)$ is the bulk modulus of solid skeleton; E denotes the Young's modulus and ν the Possion's ratio. The compressive pressure is defined to be negative.

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