Simulation of Shale Gas Transport and Production with Complex Fractures using Embedded Discrete Fracture Model

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Abstract

The goal of this study is to develop a new model to simulate gas and water transport in shale nanopores and complex fractures. We first derive a new gas diffusivity equation to consider multiple important physical mechanisms such as gas desorption, gas slippage and diffusion, and non-Darcy flow. For complex fractures, we implement a state-of-the-art embedded discrete fracture model (EDFM). We verify this numerical model against a commercial reservoir simulator for shale gas simulation with multiple planar fractures. After that, we perform a series of simulation studies to investigate the impacts of complex gas transport mechanisms and various fracture geometries on well performance. The critical parameters controlling well performance are identified. The simulation results reveal that modeling of gas production from complex fractures as well as modeling important gas transport mechanisms in shale gas reservoirs is extremely significant.

Introduction

Gas shales are characterized by extremely low permeability (nanodarcies), low porosity (2-8%) and high total organic carbon (1-14%), which can be both source rock and reservoir rock.[1] In recent years, the economic viability of shale gas production has been enabled with the advances in hydraulic fracturing technologies and horizontal drilling. It has been estimated by U.S. Energy Information Administration (EIA) that shale gas production accounts for over 50% of total U.S. natural gas production in 2015.[2] Hence, shale gas has contributed significantly to the total natural gas supply in the U.S.

Gas transport in shale formation involves complex gas transport mechanisms due to the presence of a large amount of nanopores and organic matter, which include gas desorption, adsorbed gas porosity, gas slippage, and Knudsen diffusion etc.[3-9] Yu et al.[9] reported that the adsorbed gas porosity can be up to as high as 3.8% based on the experimental measurements of gas adsorption isotherm in some area of Marcellus shale. However, this important effect has not yet been well documented and clearly understood in the literature. Furthermore, complex fracture networks are commonly observed based on microseismic measurements[10-11] and fracture propagation models,[12-15] especially in the presence of pre-existing natural fractures. In addition, fracture width and conductivity vary along fracture length, which has been observed and predicted by both experimental studies and fracture models.[14-17] Moreover, the fracture conductivity is pressure-dependent, which decrease with the reservoir depletion due to proppant embedment.[18-20] Hence, the complex gas transport mechanisms and complex fracture geometries pose a great

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challenge to accurately and efficiently evaluate and simulate well performance in shale gas reservoirs.

In recent years, considerable efforts have been made to model well performance from shale reservoirs with complex fracture geometry analytically and semi-analytically.[21-27] However, these analytical and semi-analytical approaches are difficult to fully capture the complex physics existed in shale gas reservoirs such as heterogeneity, multiphase flow (gas/water), pressure-dependent rock properties and fracture conductivity, disconnected natural fractures, and fractures with any orientation in 3D dimension, etc. In accordance, Cipolla et al.[1] stated that numerical reservoir simulation is the most rigorous method to model shale-gas reservoirs, which can incorporate the complex nature of fracture geometry and long-time transient gas flow behavior due to very low permeability of shale matrix. Regarding numerical methods with structured grid (single-porosity model), local grid refinement (LGR) is often used to model hydraulic fractures, where a small cell is placed for fracture and some cells with logarithmically increasing size are close to fracture.[28-29] However, this method is mainly limited to two simple fracture patterns such as bi-wing fractures and orthogonal fracture networks. Such fracture geometries are inadequate to represent the complex nature of fracture geometry in reality. Similarly, the traditional dual-continuum (dual-porosity or dual-permeability) numerical models[30] have the limitations for explicitly modeling complex fractures and cannot adequately account for anisotropy, heterogeneity, and fracture connectivity.[31-32]

With the recent advances in discrete fracture models using unstructured gridding with local refinement near the fractures, the true complex fracture geometry can be better modeled.[33-35]

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However, the unstructured grids are still challenging to use efficiently in the field scale due to very complicated gridding issues and an expensive computational cost. Recently, a multi-segment well approach[36-37] has been developed to dynamically model hydraulic fractures. However, this approach is difficult to handle a large number of isolated natural fractures, which has no connection to primary hydraulic fractures and wellbore. In order to overcome the above issues, a state-of-the-art embedded discrete fracture model (EDFM) was developed to use for in-house simulator developments.[38-45] Recently, it has been widely extended to use in commercial reservoir simulators in a nonintrusive manner.[32,46-50] In EDFM, the complex fractures are embedded in conventional structured matrix grids explicitly without the need of LGR in the vicinity of fractures. This approach is simpler and faster to capture the complex fracture geometries. Accordingly, the EDFM approach is fully implemented in the model development of this study. More details will be discussed later in the text. Although there are many existing numerical models for shale gas simulation,[51-55] many of the above complex phenomenon have not been completely captured, and hence it is necessary to develop a powerful model to fill this gap in the petroleum industry.

In this study, we derive a new diffusivity equation by considering complex physics such as pore volume occupied by adsorbed gas, pressure-dependent rock properties, non-Darcy flow, and multiphase flow for describing gas transport and flow in shale formations. Furthermore, we fully implement the EDFM approach in the numerical model to efficiently simulate fluid flow behavior in the complex fracture geometries. In addition, we account for the natural fractures with multiple sets and the non-planar fractures with varying fracture width and conductivity across the fracture. The pressure-dependent fracture conductivity is included. The matrix and

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fracture systems can have different sets of relative permeability curves. We verify the numerical model against a commercial reservoir simulator for simulation of gas and water flow in shale gas reservoirs with multiple planar fractures and non-Darcy flow and gas desorption effects. After verification, we perform a series of case studies to examine the impacts of various flow mechanisms discussed above, natural fractures, non-planar hydraulic fractures, pressure-dependent matrix permeability and fracture conductivity, and reservoir heterogeneity on well performance. The non-planar fracture geometry is predicted using a complex hydraulic fracture propagation model.

Mass Conservation Equation

Two-phase flow (gas/water) are considered for deriving the mass conservation equations for simulation of shale gas production in this study. Each phase is present at equilibrium considering the viscous, gravity, and capillary forces. Gas and water can also be treated as two components. It is assumed that gas and water phases are independent without component interactions. The general mass conservation equation for component i ($i = g$ for gas and $i = w$ for water) can be written as

$$\frac{\partial W_i}{\partial t} + \vec{\nabla} \cdot \vec{F}_i - R_i = 0 \tag{1}$$

where W_i, $\vec{F}_i$, R_i, and t are the accumulation, flux, source, and time terms, respectively.[56] It should be mentioned that the unit of the above equation is lb-moles per unit bulk volume per unit time.

The accumulation term for gas component considering gas saturation, gas adsorption and pore volume occupied by adsorbed gas near the pore surface is expressed below:

$$W_g = \phi S_g (1 - c_{ag}) \xi_g + (1 - \phi) \rho_s v_{ag} \xi_{ag} \tag{2}$$

where ϕ is porosity, S_g is gas saturation, c_{ag} is the volume fraction of adsorbed gas per unit pore volume, ξ_g is the molar density of gas phase, ρ_s is the rock density in ton per unit volume of solid, v_{ag} is the specific volume of gas adsorbed per unit mass of bulk rock (standard cubic feet per ton, scf/ton), ξ_{ag} is the molar density of adsorbed gas in lb-mole/ft^3.

The accumulation term for water component without considering water adsorption is below:

$$W_w = \phi S_w \xi_w \tag{3}$$

where ξ_w is the molar density of water phase in lb-mole/ft^3 and S_w is water saturation.

The flux of gas and water components can be written as

$$\vec{F}_g = \xi_g \vec{u}_g \tag{4}$$

$$\vec{F}_w = \xi_w \vec{u}_w \tag{5}$$

where $\vec{u}_g$ and $\vec{u}_w$ represent the superficial velocity of gas phase and water phase, respectively.

Based on multiphase version of Darcy's law for fluid flow in porous media, the superficial velocity of phase j ($j = g$ for gas phase and $j = w$ for water phase) becomes

$$\vec{u}_j = -\frac{\vec{\vec{k}} k_{rj}}{\mu_j} \left(\nabla p_j - \gamma_j \nabla D \right) \tag{6}$$

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k_{rj} is relative permeability, μ_j is viscosity, γ_j is the specific weight of phase j, and D is depth.

The source term is written as

$$R_i = \frac{q_i}{V_b} \tag{7}$$

where q_i is the molar flow rate of component i which is positive for injection and negative for production, V_b is the bulk volume of a gridblock.

The final mass conservation equations for gas and water components are described below:

$$\frac{\partial}{\partial t}\left[\phi S_g(1-c_{ag})\xi_g + (1-\phi)\rho_s v_{ag}\xi_{ag}\right] + \vec{\nabla}\cdot(\xi_g \vec{u}_g) - \frac{q_g}{V_b} = 0 \tag{8}$$

$$\frac{\partial}{\partial t}(\phi S_w \xi_w) + \vec{\nabla}\cdot(\xi_w \vec{u}_w) - \frac{q_w}{V_b} = 0 \tag{9}$$

Gas desorption effect. In our previous studies,[9] it was found that four experimental measurements of methane adsorption from the Marcellus Shale core samples deviate from the Langmuir isotherm, but obey the BET isotherm.[57] The standard BET isotherm assumes that the number of adsorption layers is infinite. Here, a general form of BET isotherm considering n adsorption layers is used as follows:

$$v_{ag} = \frac{v_m C\, p/p_o}{1-p/p_o}\left[\frac{1-(n+1)(p/p_o)^n + n(p/p_o)^{n+1}}{1+(C-1)\,p/p_o - C(p/p_o)^{n+1}}\right] \tag{10}$$

where v_{ag} is the gas volume of adsorption, p_o is the saturation pressure of the gas, v_m is the maximum adsorption gas volume when the adsorbent surface is being covered with a complete monomolecular layer, C is a constant. It is important to note that the saturation pressure loses its physical meaning when the reservoir temperature is above the critical methane temperature.[58]

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Instead, the saturation pressure can be treated as pseudo-saturation pressure (p_s) for the high-pressure/temperature methane adsorption,[59] which can be calculated using the following extrapolation of the Antoine equation:[60-61]

$$\ln p_s = 7.7437 - \frac{1306.5485}{19.4362 + T} \tag{11}$$

where T is temperature in K and p_s is pseudo-saturation pressure in MPa. After calculation of p_s, three parameters such as v_m, n, and C are generally used to fit the experimental data of methane adsorption. When $n = 1$, the general BET isotherm will be simplified as the classic Langmuir isotherm:[62]

$$v_{ag} = \frac{v_L p}{p + p_L} \tag{12}$$

where v_L is Langmuir volume (scf/ton), which is the maximum adsorbed gas volume at the infinite pressure, p_L is Langmuir pressure, which is the pressure at which one-half of the gas is desorbed.

Adsorbed gas porosity. In this study, the adsorbed gas density of methane is calculated by the expression proposed by Riewchotisakul and Akkutlu,[63] which is obtained based on the non-equilibrium molecular dynamic simulation to account for the change of adsorbed phase density with pressure in organic nanopores:

$$\rho_{ag} = 0.1057 \ln(p) - 0.4629 \tag{13}$$

where ρ_{ag} is the adsorbed gas density in g/cm^3 and p is pressure in psi. The variations of nanopore properties[64] such as pore size, shape and roughness are not considered in this expression. Note that the molar density of adsorbed gas can be calculated by

$$\xi_{ag} = \frac{\rho_{ag}}{M_{ag}} \tag{14}$$

where M_{ag} is molecular weight of adsorbed gas. Hence, the pore volume occupied by adsorbed

gas can be calculated by

$$c_{ag} = \frac{(1-\phi)\rho_s v_{ag} \rho_{g,ST}}{\rho_{ag}\phi} \tag{15}$$

where $\rho_{g,ST}$ is gas density at standard condition. Hence, the adsorbed gas porosity (ϕ_{ag}) is

obtained as

$$\phi_{ag} = \frac{(1-\phi)\rho_s v_{ag} \rho_{g,ST}}{\rho_{ag}} \tag{16}$$

It should be pointed out that the adsorbed gas porosity should satisfy the criterion of $0 \le \phi_{ag} < \phi$.

Since the formation is assumed to be slightly compressible, the porosity is a function of pressure

and calculated by

$$\phi = \phi_o \left[1 + c_f (p - p_o)\right] \tag{17}$$

where ϕ_o is the porosity at the reference pressure p_o, c_f is the formation compressibility.

Accordingly, the porosity change for free gas not only considers the assumption of slightly

compressible formation but also the pore volume occupied by adsorbed gas.

Gas slippage and diffusion effect. In shale formations, a large amount of nanopores result in the

presence of multiple gas flow regimes. Gas slippage and diffusion effect becomes important in

shale nanopores, especially at low pressure with reservoir depletion. Four flow regimes were

proposed by Karniadakis and Beskok[65] depending on the Knudsen number (K_n): (1) continuum

flow regime ($K_n < 0.01$); (2) slip-flow regime ($0.01 < K_n < 0.1$); (3) transition regime (

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$0.1 < K_n < 10$); and (4) free molecular flow regime ($K_n > 10$). The Knudsen number is defined by

$$K_n = \frac{\lambda}{d} \tag{18}$$

where d is the pore diameter and λ is the mean free path of gas molecules, which is computed by[66]

$$\lambda = \frac{k_B T}{\sqrt{2}\pi\sigma^2 p} \tag{19}$$

where k_B is the Boltzmann constant (1.3805×10^-23 J/K), T is temperature in K, p is pressure in Pa, and σ is diameter of gas molecules.

For shale gas reservoirs with low and ultra-low permeability, the following apparent permeability model proposed by Florence et al.[67] is used to account for the gas slippage and diffusion effect:

$$k_a = k_i \left[1+\alpha(K_n)K_n\right]\left(1+\frac{4K_n}{1+K_n}\right) \tag{20}$$

where k_a is apparent matrix permeability, k_i is the initial matrix permeability, $\alpha(K_n)$ represents the rarefaction parameter, which can be calculated by[65]

$$\alpha(K_n) = \frac{128}{15\pi^2}\tan^{-1}(4K_n^{0.4}) \tag{21}$$

Similarly, the other existing apparent permeability models considering complex nanopore phenomena such as surface diffusion of adsorbed gas in the literature can be easily added in the current numerical model.[3,5-7,68] However, the comparison of different apparent permeability models is beyond the scope of this study.

Non-Darcy flow effect. It is assumed that the non-Darcy flow effect only occurs for gas flow inside fractures. The non-Darcy flow is widely modeled using the Forchheimer modification to Darcy's law and is written as

$$-\nabla \Phi_g = \frac{\mu_g}{k \cdot k_{rg}} \vec{u}_g + \beta_g \rho_g \left| \vec{u}_g \right| \vec{u}_g \tag{22}$$

where Φ_g is the potential of gas phase, ρ_g is gas density, β_g is the non-Darcy Forchheimer coefficient, which can be determined using the correlation proposed by Evans and Civan[69] as given below:

$$\beta_g = \frac{1.485 \times 10^9}{k^{1.021}} \tag{23}$$

where the unit of permeability is md and the unit of β_g is ft^{-1}. This correlation was obtained based on more than 180 data points including those for propped fractures and a good match is obtained with a correlation coefficient of 0.974.[28] This correlation will be implemented into the numerical model in this study.

Pressure-dependent matrix permeability. We use the empirical equation developed by Jones[70] according to experimental data to handle the correlation between the change of matrix permeability and net effective stress as follows:

$$\frac{k}{k_i} = \exp \left\{ a_k \left[\exp(-\sigma_e / \sigma^*) - 1 \right] \right\} \Big/ (1 + C'\sigma_e) \tag{24}$$

where a_k is a constant, σ^* is a decay constant, which is arbitrarily given as 3,000 psi, C' is a constant, which is arbitrarily set to 3×10^{-6} psi^{-1},[70] σ_e is the net effective stress, which is defined by

$$\sigma_e = \sigma - \alpha \, p_r \tag{25}$$

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where σ is the confining stress, p_r is pore pressure, α is Biot's constant, which can be calculated for an ideal uniaxial strain scenario:[71]

$$\alpha = 1 - \frac{c_m}{c_b} \tag{26}$$

where c_m is rock matrix compressibility and c_b is rock bulk compressibility.

Pressure-dependent fracture permeability. It has been recognized that fracture conductivity, which refers to fracture permeability multiplied by fracture width, is challenging to maintain a constant high value in reality, whereas it often declines with the increasing closure pressure due to proppant embedment, proppant crushing etc. This phenomenon is more serious when the shale rock is soft. Through fitting the laboratory measurement data for different shale core samples ranging from still to soft (Figure 1),[20] the relationships between normalized fracture conductivity and closure pressure were obtained below:[72]

$$\text{Stiff shale: } \log(FC_N) = -0.0001 \times \sigma_c - 0.1082, R^2 = 0.954 \tag{27}$$

$$\text{Medium shale: } \log(FC_N) = -0.0004 \times \sigma_c + 0.2191, R^2 = 0.998 \tag{28}$$

$$\text{Soft shale: } \log(FC_N) = -0.0006 \times \sigma_c - 0.4256, R^2 = 0.987 \tag{29}$$

where FC_N is normalized fracture conductivity divided by the initial fracture conductivity, and σ_c is closure pressure in psi. The above equations will be implemented in the numerical model in this study.

Embedded Discrete Fracture Model

We use the state-of-the-art EDFM approach to handle complex fracture geometries. The EDFM has been approved to be a powerful method to model complex fracture geometries in unconventional oil and gas reservoir simulation. The EDFM method borrows concepts from both

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dual-continuum model and discrete fracture models. In this method, a fracture with any shape is discretized into small segments based on the matrix block boundaries. Correspondingly, in the computational domain, some additional virtual cells are created to represent these segments. To accurately simulate fluid flow associated with these fracture segments, the non-neighboring connections (NNCs) are defined for these virtual blocks and transmissibility factors are calculated.

In the EDFM approach, all connections can be classified into four basic types, including flow between matrix blocks and fractures, flow between fracture segments inside an individual fracture, flow between intersecting fracture segments, and flow between fracture segment and the wellbore it intersects. The first three types of connections are simulated using transmissibility factors between blocks, and the volume flow rate (q) of phase l between blocks in a NNC pair can be express as

$$q = \lambda_l T_{NNC} \Delta p \tag{30}$$

where λ_l is the relative mobility of phase l, T_{NNC} is the transmissibility factor, and Δp is the potential difference between corresponding blocks.

Generally, T_{NNC} can be expressed as

$$T_{NNC} = \frac{k_{NNC} A_{NNC}}{d_{NNC}} \tag{31}$$

where k_{NNC}, A_{NNC}, and d_{NNC} represent the permeability, common area, and distance for the connection, respectively.

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For flow between fracture and matrix, k_{NNC} is the matrix permeability, A_{NNC} is the area of the fracture segment, and d_{NNC} is the average normal distance from matrix block to fracture segment. For flow between fracture segments (within individual fracture or between intersecting fractures), k_{NNC} is the fracture permeability, A_{NNC} is the common area between fracture segments, and d_{NNC} is the distance between fracture segments.

Similarly, fracture-wellbore intersections are modeled by treating fracture segments as wellblocks and assigning well indices. The calculation of well indices is similar to Peaceman's model. More details of the transmissibility factor and well index calculation can be found in Moinfar et al.[40] and Xu et al.[32]

Finally, the finite difference method is utilized to solve the coupled and highly nonlinear partial differential equations. Under the assumption of isothermal shale-gas reservoir, the unknowns should be specified initially include reservoir pressure and the number of moles for each component. In addition, no flow boundary condition is considered. An implicit pressure, explicit composition technique is used to solve for the unknowns such as pressure and component moles. More details can be found in the work by Chang.[73] The physical properties of real gas such as density, viscosity and compressibility are calculated using Peng-Robinson equation of state.[74-75]

Model Verification for Planar Hydraulic Fractures

We set up a basic 3D reservoir model with dimensions of 2020 ft × 1500 ft × 130 ft (615.70 m × 457.20 m × 39.624 m), which corresponds to reservoir length, width, and thickness, respectively, as shown in Figure 2. The dimension of grid size is 20 ft × 20 ft × 130 ft (6.096 m × 6.096 m × 39.624 m). A synthetic shale-gas case with 11 planar hydraulic fractures was simulated with the

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purpose of verifying the new developed model against a commercial reservoir simulator.[76] The commercial simulator utilizes the LGR approach to handle hydraulic fracture. Each block containing hydraulic fracture is refined by 5×1×1. Our model uses the EDFM approach to deal with hydraulic fracture without the need of grid refinement near the fracture. The other reservoir and fracture properties used for the simulations are summarized in Table 1. The gas type is methane. The reservoir is assumed to be homogeneous with two phase flow of gas and water. The initial water saturation is assumed to be 50% for the purpose of verification. It should be mentioned that the effects of capillary pressure and nanopore confinement on fluid transport are not included in the current study,[77] which will be examined in detail in our future study. Figure 3 presents different relative permeability curves for the matrix and fracture system, respectively. The constant flowing bottomhole pressure (BHP) of 500 psi (3.45 MPa) is assumed for the simulation constraint over time. Fracture height is assumed to fully penetrate reservoir thickness. Gas desorption is considered using Langmuir isotherm, which is available in the commercial reservoir simulator. Note that the influence of the existing water phase on gas adsorption capacity is not considered in this study, which needs more fundamental research. The non-Darcy flow effect for both hydraulic and natural fractures is considered using the non-Darcy Forchheimer coefficient proposed by Evans and Civan.[69]

Figure 4 compares the simulation results of both flow rates and cumulative production for gas and water at a 30-year period between our model and the commercial reservoir simulator. As can be seen, a good match is obtained between them. It implies that our numerical model in conjunction with the EDFM approach can simulate shale-gas production with planar fractures by considering gas desorption and non-Darcy flow effects. Figure 5 shows the pressure distribution

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after 30 years of production. It can be observed that the effective drainage area can be clearly demonstrated.

Complex Gas Transport Mechanisms

In the following sections, we examined the impacts of complex gas transport mechanisms on well performance such as gas desorption, gas slippage and diffusion in more detail. It is important to point out that the initial water saturation is changed to 20%, which is the residual water saturation. Hence, there is only gas flow for the following case studies. The other input parameters remain the same as those in Table 1.

Gas desorption effect. In our previous study associated with gas desorption,[9] it has been found that the BET isotherm performs a better match than Langmuir isotherm with the measured methane adsorption under high reservoir pressure, as shown in Figure 6. The fitting parameters of BET isotherm such as $v_m = 49.01$ scf/ton, $C = 24.56$, and $n = 4.46$ are used in this study. Figure 7 shows the effects of gas adsorption using BET isotherm with and without considering adsorbed gas porosity on well performance. It can be illustrated that the relative contribution of gas desorption on well performance after 30 years without considering the adsorbed gas porosity is around 11% compared to the case without considering gas desorption. However, it will decrease to around 5% when considering the adsorbed gas porosity. Hence, the adsorbed gas porosity effect significantly affects well performance, which has been usually neglected in the literature.

Gas slippage and diffusion effect. Figure 8 presents the effect of gas slippage and diffusion on well performance by considering various nanopore sizes between 5 nm to 50 nm. It can be observed that the smaller the nanopore size, the higher ultimate gas recovery. This is because the smaller pore size leads to larger Knudsen number, and then the ratio of apparent permeability to

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initial matrix permeability in Eq. 20 increases accordingly, especially at lower reservoir pressure, resulting in higher gas recovery. The positive contribution of gas slippage and diffusion effect to ultimate gas recovery after 30 years is about 13% and 7% with respect to the nanopore size 5 nm and 10 nm, respectively, when compared to the case without considering the effect. However, the nanopore size of 50 nm has negligible impact on well performance in this study.

Figure 9 shows the combining effects of gas desorption, adsorbed gas porosity, gas slippage and diffusion discussed in the preceding on well performance. The nanopore size of 5 nm is assumed. It clearly shows that a significant increase of ultimate gas recovery of 18% after 30 years of production is determined when compared to the case without considering the combining effects. Figure 10 shows the comparison of pressure distribution after 30 years with and without considering the combining effects. As shown, a faster reservoir depletion occurs when considering the combing effects. Accordingly, it can be concluded that it is extremely important to consider all of these important complex gas transport mechanisms in nanopores and organic matter in order to accurately simulate shale gas production.

Natural Fracture Effect

Next, the effect of natural fractures in combination with 11 planar hydraulic fractures described in the preceding on well performance is investigated. We designed three cases with different number and set of natural fractures, as shown in Figure 11. Case 1 is with 100 one-set natural fractures. Case 2 is with 200 one-set natural fractures. Case 3 is with 200 two-set natural fractures. It should be pointed out that a statistical method was used to generate the natural fracture properties, which are normally distributed in the reservoir of interest. For cases 1 and 2, the natural fractures are oriented at 5-10 degree along the horizontal wellbore, which are almost

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perpendicular to hydraulic fractures. The natural fractures length ranges from 100 ft (30.48 m) to 300 ft (91.44 m). For Case 3, one set of natural fractures is oriented at 45-55 degree and another set is 135-145 degree. Similarly, the length of natural fractures ranges from 100 ft (30.48 m) to 300 ft (91.44 m). The conductivity of natural fractures for each case is assumed to be 10 md-ft $(3.01{\times}10^{-15}$ m^2-m) and the conductivity of hydraulic fractures is 100 md-ft $(3.01{\times}10^{-14}$ m^2-m). The natural fracture height is assumed equal to the reservoir thickness. The effects of non-Darcy flow, gas desorption, adsorbed gas porosity, and nanopore size of 5 nm are considered.

Figure 12 compares the effects of different number and sets of natural fractures on well performance. As shown, the natural fractures have a critical effect on well performance. The increase of ultimate gas recovery after 30 years compared to base case without natural fractures is 6.3%, 7.8%, and 23.2% for Cases 1, 2, and 3, respectively. Figure 13 shows the comparison of pressure distribution after 1000 days and 30 years of production for each case. It can be clearly demonstrated that there is a larger effective drainage area for cases 1-3 than that for base case without natural fractures [Figures 13a and 13b]. In addition, there is a little difference between Case 1 and Case 2. This is because the number of natural fractures connected with hydraulic fractures increase slightly with an increase of fracture number from 100 to 200, resulting in a little bit increase of drainage area [Figures 13e and 13f vs. Figures 13c and 13d]. However, there are more number of natural fractures connected to hydraulic fractures directly or indirectly for Case 3, leading to a much more complex connected fracture network and a bigger expansion of drainage area than cases 1 and 2 [Figures 13g and 13h]. Hence, it can be predicted that it is important to create a better connected complex fracture network during the actual fracturing process, which is vital to maximizing the stimulation effectiveness and production optimization.

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The influences of detailed natural fracture conductivity, density, orientation, distribution on well performance will be examined in more detail in our future study.

Complex Non-Planar Fracture Geometry

In this study, a complex hydraulic fracture propagation model, developed by Wu and Olson,[78] is used to predict complex non-planar fracture geometry through modeling the interaction between hydraulic fractures and natural fractures. The model couples rock deformation and fluid flow in the fractures and horizontal wellbore. The core solid mechanics solution is three dimensional, such that fracture opening, shearing and stress shadow effects are accurately determined for single and multi-fracture cases.[15] Fluid flow in the fracture and the associated pressure drop are based on lubrication theory, assuming the fracture is analogous to a slot between parallel plates and the fluid is non-Newtonian. A constant total fluid injection rate is given. Partitioning of flow rate into each fracture is dynamically calculated in such way that the wellbore pressure is constrained to gradually decrease along the lateral due to wellbore friction. The interaction of hydraulic and natural fractures is described through analyzing induced stresses at the fracture tips. Stochastic realization methods were used to describe natural fracture patterns.[78] Length of natural fractures follows a power-law distribution. The model has been validated against known analytical solutions for single hydraulic fracture growth.[79] To demonstrate the validity of capturing the physical process of fracture interaction, the model has also been compared to a numerical model[12] in case of multiple fracture propagation. The primary assumptions for the current fracture model include: transverse fractures are initiated perpendicular to the horizontal wellbore with a nominal initial length; fracture height is constant; proppant transport and poroelastic effects are not considered. In this study, the parameters used for the fracture model include fluid injection rate of 20 barrels per minute (bbl/min) and injection time of 10 minutes

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for each fracture, Young's modulus of 3×10^6 psi (2.07×10^4 MPa), Poisson ratio of 0.23, the difference of minimum and maximum horizontal stress of 500 psi, and fluid leak-off coefficient of 5×10^{-3} ft/min$^{0.5}$ (1.524×10^{-3} m/min$^{0.5}$). Figure 14 shows the distribution of fracture width of the generated complex non-planar fracture geometry for a synthetic shale-gas case. For this case study, there are 11 non-planar fractures evenly spaced 140 ft (42.672 m) and 100 natural fractures. As shown, the distribution of fracture width is highly non-uniform.

Next, the complex fracture geometry was transformed to reservoir model, as shown in Figure 15. The non-uniform fracture width results in varying fracture conductivity across the fractures ranging from 0.1 md-ft (3.01×10^{-17} m^2-m)to 48 md-ft (14.45×10^{-15} m^2-m). The natural fracture conductivity is 10 md-ft (3.01×10^{-15} m^2-m). The other input parameters are kept the same as those in Table 1. The combing effects of non-Darcy flow, gas desorption, adsorbed gas porosity, and nanopore size of 5 nm are considered. In addition, the effects of pressure-dependent matrix permeability and fracture conductivity are included. We use Eq. 24 with a_k of 2.7442 and Eq. 28 to generate the pressure-dependent matrix permeability and fracture conductivity, respectively, as shown in Figure 16. Here, it should be mentioned that both hydraulic and natural fractures are assumed to use the same generated pressure-dependent fracture conductivity curve in this study. Different curves for different fractures will be investigated in our future study. The normalized decline rate means that the matrix permeability and fracture conductivity at different pressure divided initial matrix permeability and fracture conductivity. As shown, the matrix permeability and fracture conductivity at BHP of 500 psi (3.45 MPa) are about 20% and 8% of initial values for this case study. Figure 17 presents the effects of pressure-dependent matrix permeability and fracture conductivity on well performance individually or simultaneously. It can be clearly

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observed that pressure-dependent effect significantly declines the gas recovery. The ultimate gas recovery after 30 years is decreased by 16%, 20%, and 31% for pressure-dependent matrix permeability, fracture conductivity, and both, respectively, when compared to the case without considering these effects. Figure 18 presents the comparison of pressure distribution of different scenarios after 1000 days and 30 years. As shown, the drainage area is mainly concentrated nearby the fractures when only considering pressure-dependent matrix permeability [Figures 18c and 18d vs. Figures 18a and 18b]. However, when only taking into account pressure-dependent fracture conductivity, the effective drainage area becomes further smaller after 1000 days [Figure 18c vs. Figure 18e], whereas the reservoir depletion becomes more wider after 30 years due to the dominate role of matrix permeability at later times [Figure 18d vs. Figure 18f]. When the effects of pressure-dependent of both matrix permeability and fracture conductivity are included, the drainage area and reservoir depletion are much smaller than the case without these effects [Figures 18g and 18h vs. Figures 18a and 18b]. Hence, it is highly recommended that pressure-dependent rock and fracture properties should be carefully characterized based on laboratory measurements in order to achieve an optimal treatment design in shale gas reservoirs.

Finally, we investigate the impact of reservoir heterogeneity on well performance. A range of matrix permeability between 0.0001 md (100 nD) and 0.001 md (1000 nD) is considered. Figure 19 represents the distribution of matrix permeability in the reservoir. Correspondingly, the average equivalent matrix permeability is calculated as about 0.0005 md (500 nD). The comparison of well performance between the homogeneous and heterogeneous scenarios is shown in Figure 20. It can be clearly seen that the relative difference of ultimate gas recovery after 30 years between the heterogeneous case and the homogeneous case with the minimum

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permeability of 0.0001 md is as high as 35%. It is about 27% between the heterogeneous case and the homogeneous case with the maximum permeability of 0.001 md. However, the difference between the heterogeneous case and the homogeneous case with average equivalent permeability of 0.0005 md is small, which is about 5% after 30 years. Hence, it is important to properly characterize the distribution of matrix permeability in order to perform a better production prediction in shale gas reservoirs.

Conclusions

In this study, we developed a new multi-mechanism numerical model through fully incorporating a state-of-the-art EDFM approach to simulate shale gas production more accurately and efficiently. A good match of two-phase (gas/water) flow between the new model and the commercial reservoir simulator was obtained for a shale-gas case with planar hydraulic fractures. The impacts of various gas transport physics, natural fractures, non-planar fractures, pressure-dependent rock and fracture properties and heterogeneity on well performance were investigated in more detail. The following conclusions can be drawn based on the simulation results of this study:

(1) The gas desorption effect without considering the adsorbed gas density may overestimate the ultimate gas production. An overestimate of ultimate gas production of 6% after 30 years was observed in this study.

(2) Gas slippage and diffusion effect in shale nanopores significantly impacts well productivity. The ultimate gas production after 30 years can be increased by about 13% with nanopore size of 5 nm. However, this effect might become less important when nanopore size is in excess of a critical value, for example, 50 nm in this study.

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(3) The combining effects of non-Darcy flow, gas desorption, adsorbed gas porosity, gas slippage and diffusion are important physics for affecting well performance. A significant increase of gas recovery of 18% after 30 years was achieved compared with the case ignoring these components.

(4) The number of set of natural fractures has a great effect on well performance due to the formation of a more connected complex fracture networks. Two-set natural fractures contributes to an increase of gas recovery of 23.2% after 30 years, whereas one-set natural fracture only contributes to an increase of gas recovery of 7.8% under the same number of 200.

(5) This model allows to handle complex non-planar fracture geometry with varying fracture with and fracture conductivity along fracture length, which is generated by a complex hydraulic fracture propagation model.

(6) Pressure-dependent matrix permeability and fracture conductivity effects have a significant negative influence on well performance and reservoir drainage efficiency. A significant reduction of gas recovery of 31% after 30 years was obtained compared with the case without considering these effects. Detailed laboratory measures of pressure-dependent shale and fracture properties are highly recommended in order to accurately evaluate well performance and stimulation effectiveness.

(7) Heterogeneity of matrix permeability plays a vital role in well productivity. A big difference of 35% and 27% was observed between the heterogeneous case and the homogeneous case with the minimum permeability of 0.0001 md and the maximum permeability of 0.001 md, respectively. The converted equivalent average matrix permeability has a small difference of well performance compared with the heterogeneous case.

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Acknowledgments

Notation

EDFM	=	Embedded Discrete Fracture Model
BET	=	Brunauer, Emmett and Teller
EIA	=	Energy Information Administration
LGR	=	Local grid refinement
NNCs	=	Non-neighboring connections
BHP	=	Bottomhole pressure
MMscf	=	10^6 Standard cubic feet
scf	=	standard cubic feet
W_i	=	the accumulation term, lb-moles/ft^3/s
$\vec{F}_i$	=	the flux term, lb-moles/ft^3/s
R_i	=	the source term, lb-moles/ft^3/s
t	=	time, second
ϕ	=	porosity
S_g	=	gas saturation
c_{ag}	=	volume fraction of adsorbed gas per unit pore volume
ξ_g	=	molar density of gas phase, lb-mole/ft^3

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ρ_s = rock density, ton/ft^3

v_{ag} = specific volume of gas adsorbed per unit mass of bulk rock, scf/ton

ξ_{ag} = molar density of adsorbed gas, lb-mole/ft^3

ξ_w = molar density of water phase, lb-mole/ft^3

S_w = water saturation

$\vec{u}_g$ = superficial velocity of gas phase, m/s

$\vec{u}_w$ = superficial velocity of water phase, m/s

k_{rj} = relative permeability of phase j

μ_j = viscosity of phase j, cp

γ_j = specific weight of phase j

D = depth, ft

q_i = molar flow rate of component i, lb-mole/s

V_b = bulk volume of a gridblock, ft^3

v_{ag} = gas volume of adsorption, scf/ton

p_o = saturation pressure of the gas, psi

v_m = the maximum adsorption gas volume, scf/ton

C = a constant value

T = temperature, K

p_s = pseudo-saturation pressure, MPa

v_L = Langmuir volume, scf/ton

p_L = Langmuir pressure, psi

ρ_{ag} = adsorbed gas density, g/cm^3

p = pressure, psi

M_{ag} = molecular weight of adsorbed gas, kg/mole

$\rho_{g,ST}$ = gas density at standard condition, g/cm^3

ϕ_o = porosity at the reference pressure p_o

c_f = formation compressibility, 1/psi

K_n = Knudsen number

d = the pore diameter, nm

λ = the mean free path of gas molecules, nm

k_B = the Boltzmann constant, J/K

σ = diameter of gas molecules

k_a = apparent matrix permeability, md

k_i = initial matrix permeability, md

$\alpha(K_n)$ = the rarefaction parameter

Φ_g = potential of gas phase, psi

ρ_g = gas density, g/cm^3

β_g = the non-Darcy Forchheimer coefficient, 1/ft

a_k = a constant value

σ^* = a decay constant, psi

C' = a constant value, 1/psi

σ_e = net effective stress, psi

σ = the confining stress, psi

p_r = pore pressure, psi

α	=	Biot's constant
c_m	=	rock matrix compressibility, 1/psi
c_b	=	rock bulk compressibility, 1/psi
FC_N	=	normalized fracture conductivity
σ_c	=	closure pressure, psi
λ_l	=	relative mobility of phase l, cp^{-1}
T_{NNC}	=	transmissibility factor, md-ft
Δp	=	potential difference between corresponding blocks, psi
q	=	volume of flow rate, ft^3/d
k_{NNC}	=	permeability for the connection, md
A_{NNC}	=	common area for the connection, ft^2
d_{NNC}	=	distance for the connection, ft

SI Metric Conversion Factors

ft	×	3.048	e-01	=	m
ft^3	×	2.832	e-02	=	m^3
cp	×	1.0	e-03	=	Pa·s
psi	×	6.895	e+00	=	kPa
md	×	1e-15	e+00	=	m^2
days	×	8.64	e+4	=	seconds
ton	×	9.072	e+02	=	kg
^{o}F		(^{o}F-32)/1.8		=	^{o}C

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Table 1. Basic parameters used for the simulations

Parameter	Value	Field Unit	Value	SI Unit
Initial reservoir pressure	4000	psi	27.58	MPa
Reservoir temperature	130	^{o}F	327.59	K
Reservoir thickness	130	ft	39.624	m
Reservoir permeability	800	nD	0.0008	mD
Reservoir porosity	12%	-	12%	-
Initial gas saturation	50%	-	50%	-
Gas gravity	0.58	-	0.58	-
Total compressibility	3×10^{-6}	psi^{-1}	0.000435	MPa^{-1}
Fracture half-length	350	ft	106.68	m
Fracture conductivity	100	md-ft	3.01×10^{-14}	m^2-m
Fracture height	130	ft	39.624	m
Fracture width	0.01	ft	0.003048	m
Fracture spacing	140	ft	42.672	m
Langmuir pressure	1300	psi	8.96	MPa
Langmuir volume	140	scf/ton	3.964	m^3/ton
Rock density	2.5	g/cm^3	2.5×10^3	kg/m^3

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Figure captions

Figure 1. The relationship between normalized fracture conductivity and closure pressure for three different shale samples: stiff, medium, and soft rock.

Figure 2. A basic 3D reservoir model for a horizontal well with 11 planar hydraulic fractures.

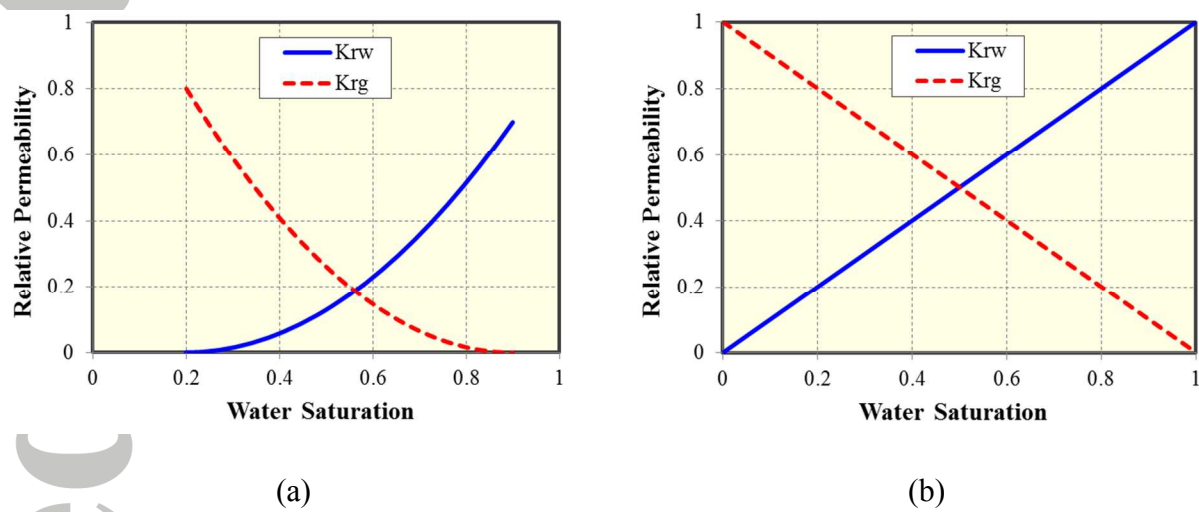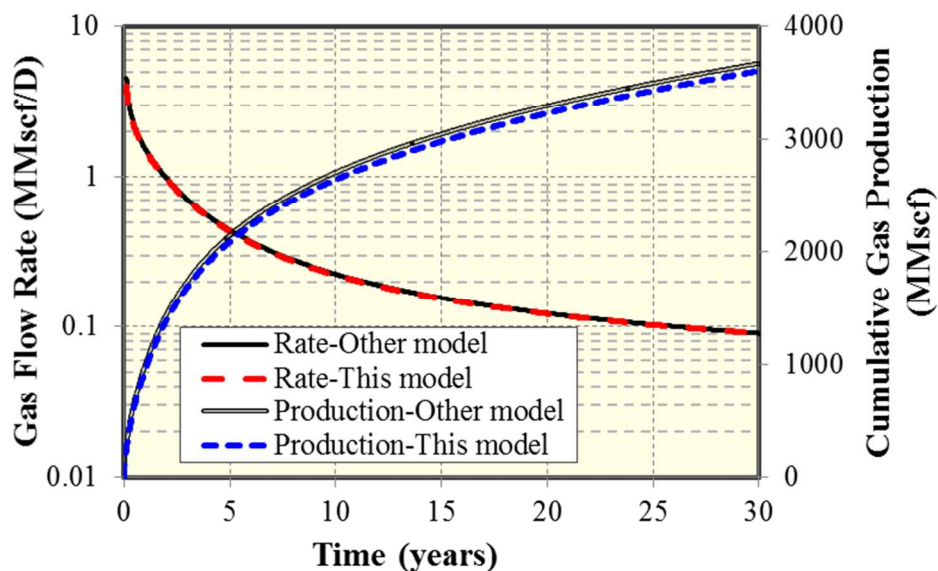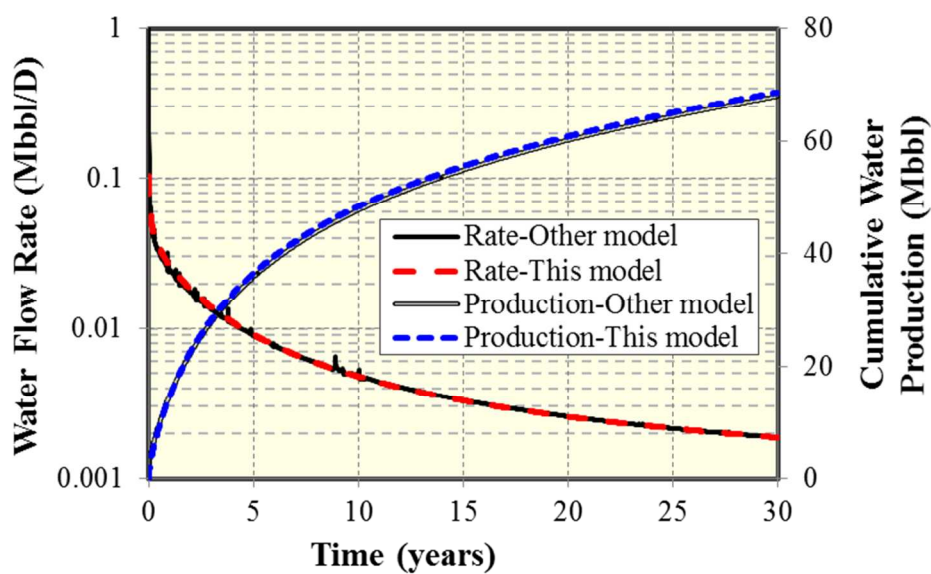**Figure 3. Different relative permeability curves used for two-phase shale-gas simulation [(a) matrix system; (b) fracture system].**
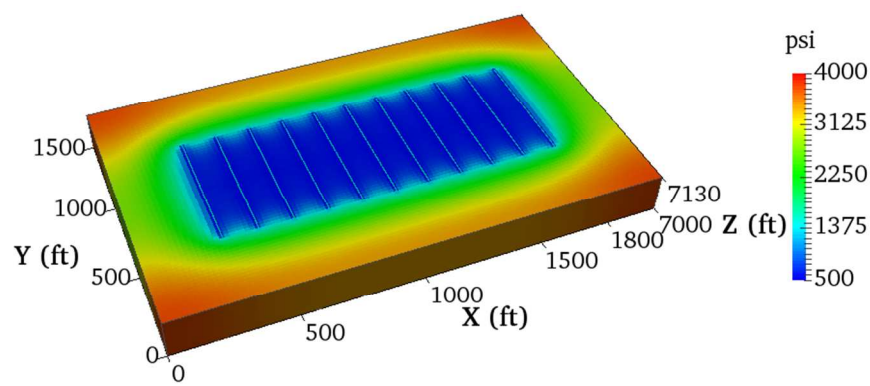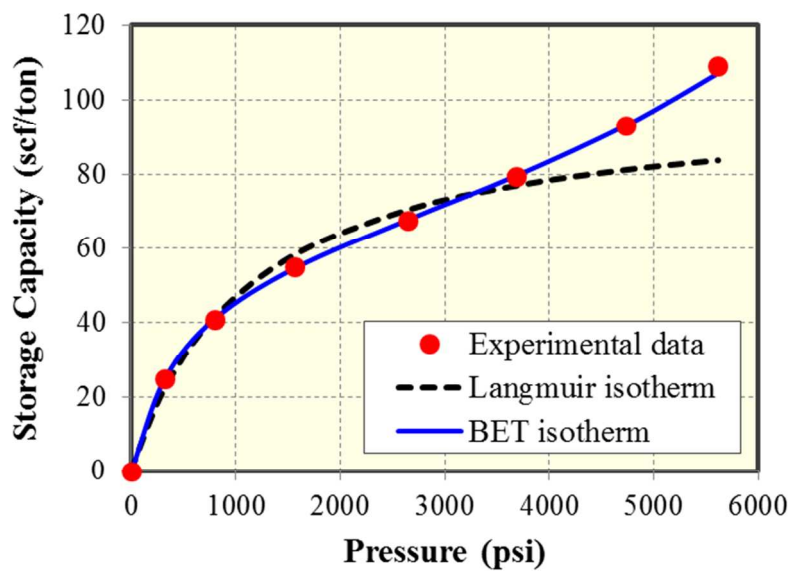
Figure 4. Comparison of simulation results of flow rates and cumulative production at a 30-year period between this model and commercial reservoir simulator [(a) gas flow rate and cumulative gas production; (b) water flow rate and cumulative water production].

Figure 5. Pressure distribution using this model after 30 years of production.

Figure 6. Experimental data of methane desorption at high pressure obeying BET isotherm other than Langmuir isotherm.
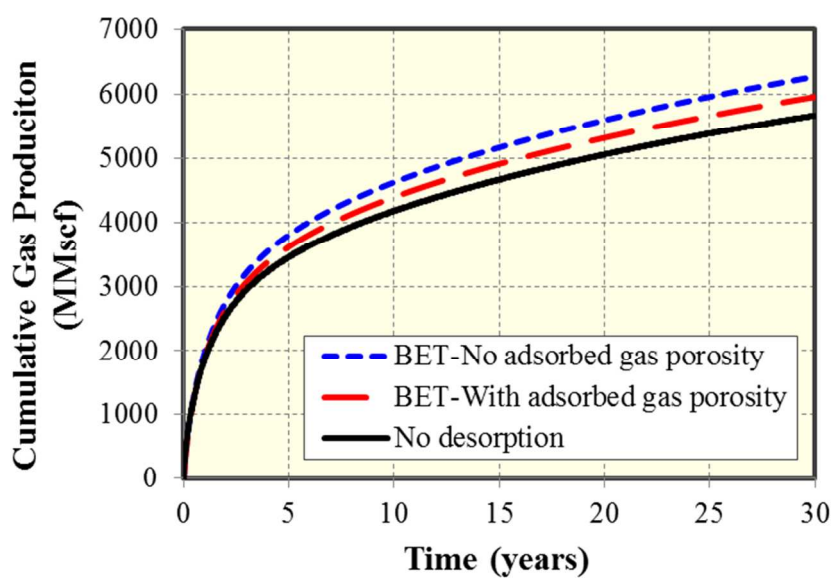
Figure 7. Effects of gas adsorption and adsorbed gas porosity well performance.
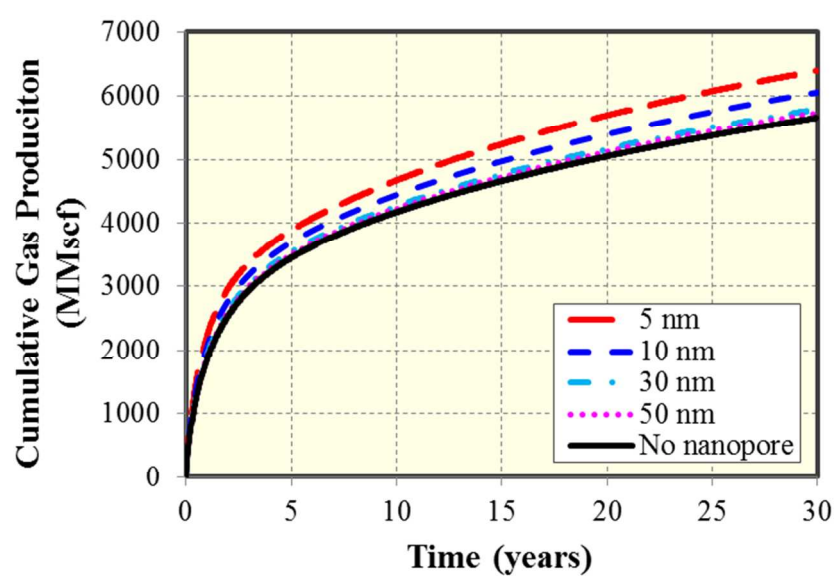
Figure 8. Effect of gas slippage and diffusion on well performance with various nanopore sizes between 5 nm to 50 nm.
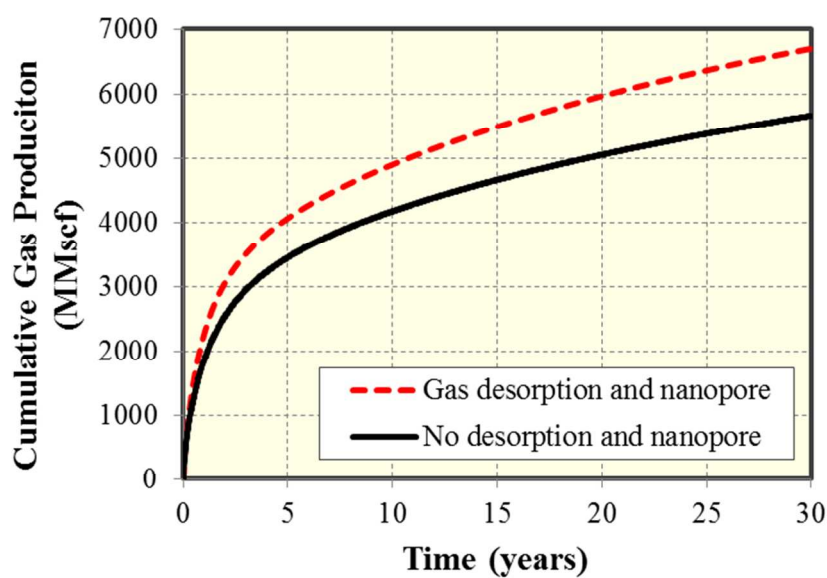
Figure 9. Effects of the combination effects of gas desorption, adsorbed gas porosity, gas slippage and diffusion on well performance.

Figure 10. Comparison of pressure distribution after 30 years with and without considering the combining effects of gas desorption, adsorbed gas porosity, and gas slippage and diffusion [(a) with the combing effects; (b) Without the combing effects].

Figure 11. Three cases with different natural fracture settings (grey color represents natural fractures) [(a) case 1 with 100 one-set natural fractures; (b) case 2 with 200 one-set

1
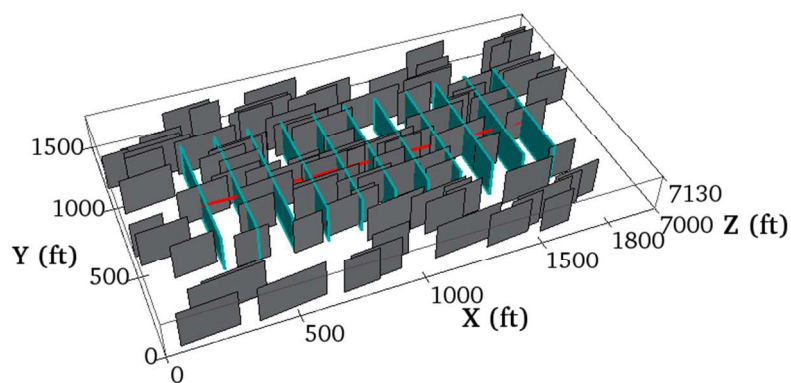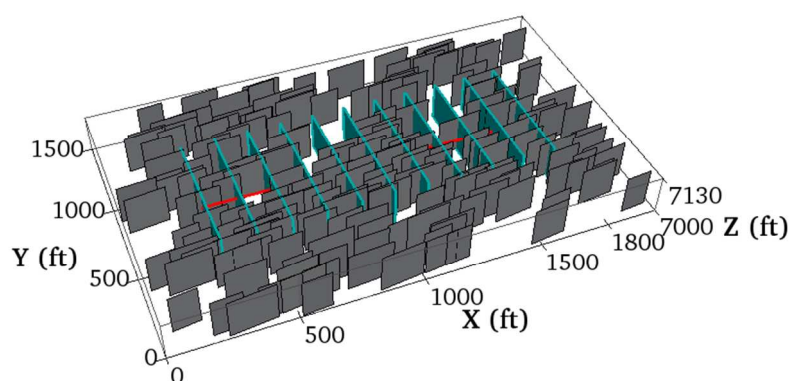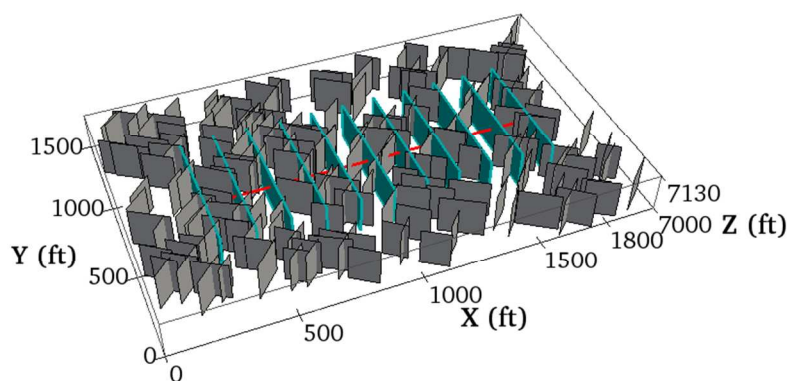
natural fractures; (c) case 3 with 200 two-set natural fractures].

Figure 12. Effects of different number and sets of natural fractures on well performance (NF represent natural fracture).
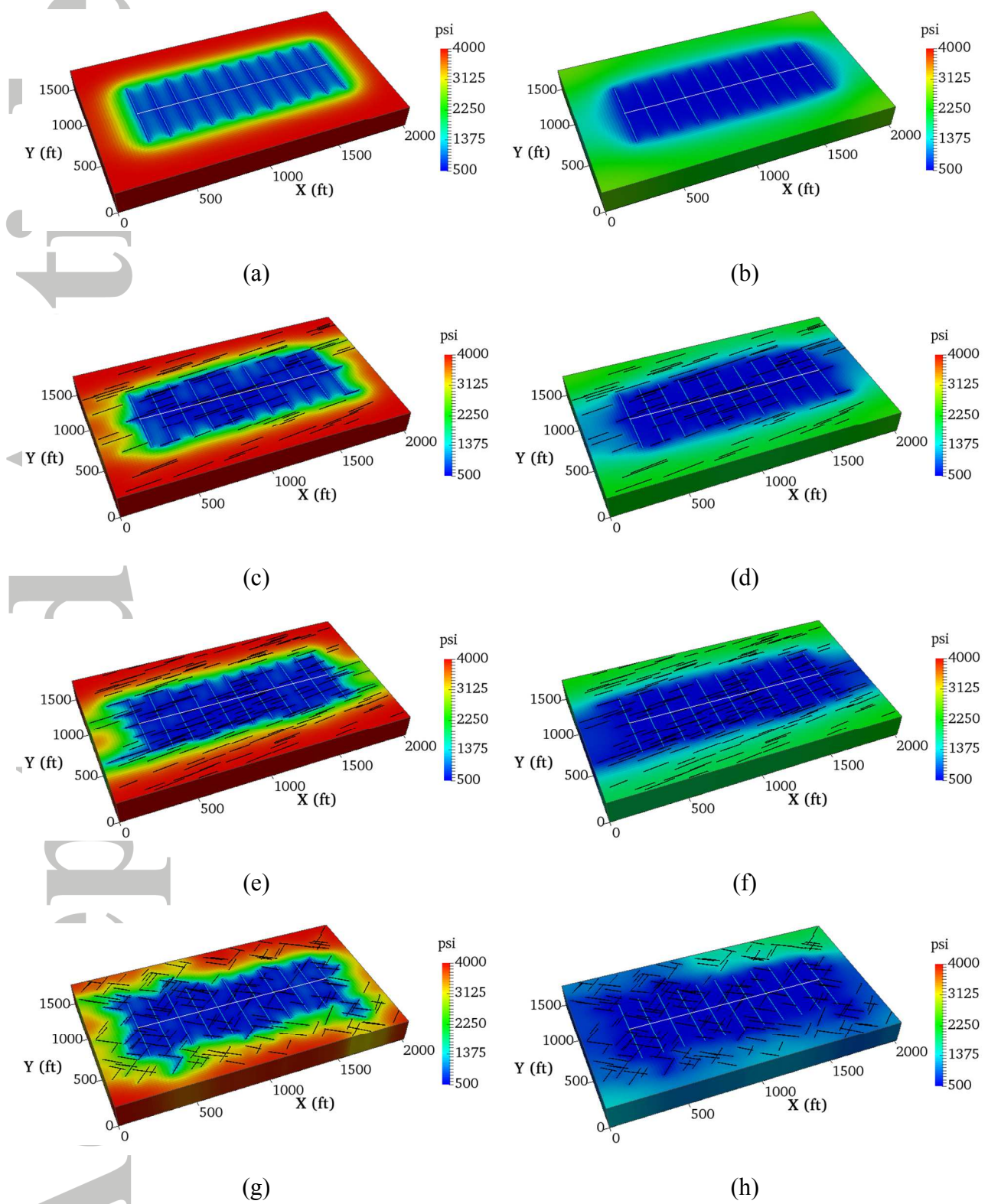
Figure 13. Comparison of pressure distribution for different cases after 1000 days and 30 years [(a) base case without NF after 1000 days; (b) base case without NF after 30 years; (c) case 1 after 1000 days; (d) case 1 after 30 years; (e) case 2 after 1000 days; (f) case 2 after 30 years; (g) case 3 after 1000 days; (h) case 3 after 30 years].
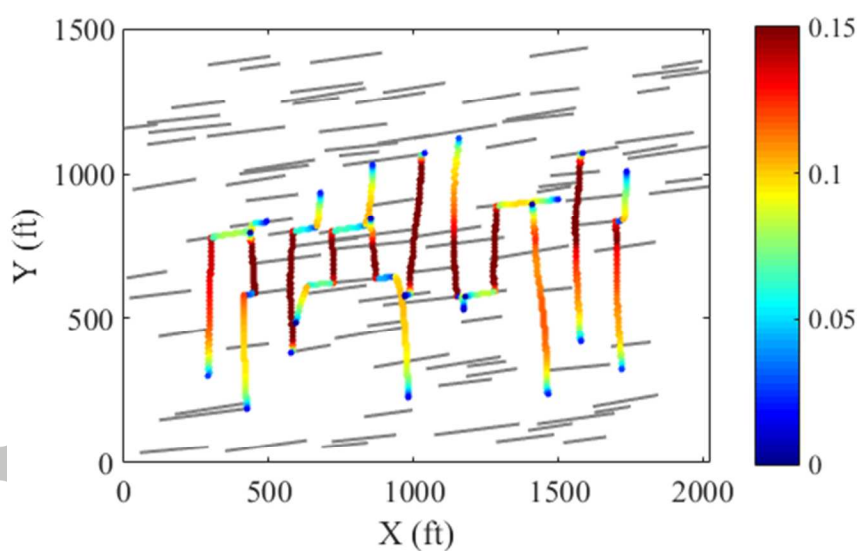
Figure 14. Distribution of fracture width of generated complex non-planar fracture geometry predicted by the fracture model for a synthetic shale-gas case (grey lines represent natural fractures).

Figure 15. Complex non-planar fracture geometry with 100 natural fractures in a synthetic shale-gas case.

Figure 16. Pressure-dependent curves of matrix permeability and fracture conductivity used in this study.

Figure 17. Effects of pressure-dependent matrix permeability and fracture conductivity on well performance.

Figure 18. Comparison of pressure distribution for different scenarios after 1000 days and 30 years [(a) without pressure-dependent effect after 1000 days; (b) without pressure-dependent effect after 30 years; (c) pressure-dependent matrix permeability after 1000 days; (d) pressure-dependent matrix permeability after 30 years; (e) pressure-dependent fracture conductivity after 1000 days; (f) pressure-dependent fracture conductivity after 30 years; (g) pressure-dependent of both after 1000 days; (h) pressure-dependent of both after 30 years].

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Figure 19. Distribution of matrix permeability in the reservoir with complex non-planar fracture geometry and natural fractures.

Figure 20. Comparison of well performance between homogeneous and heterogeneous scenarios.

Table 1. Basic parameters used for the simulations

Figure 1. The relationship between normalized fracture conductivity and closure pressure for three different shale samples: stiff, medium, and soft rock.

Figure 2. A basic 3D reservoir model for a horizontal well with 11 planar hydraulic fractures.

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(a)

(b)

Figure 3. Different relative permeability curves used for two-phase shale-gas simulation

[(a) matrix system; (b) fracture system].

(a)

(b)

Figure 4. Comparison of simulation results of flow rates and cumulative production at a 30-year period between this model and commercial reservoir simulator [(a) gas flow rate and cumulative gas production; (b) water flow rate and cumulative water production].

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Figure 5. Pressure distribution using this model after 30 years of production.

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Figure 6. Experimental data of methane desorption at high pressure obeying BET isotherm other than Langmuir isotherm.

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Figure 7. Effects of gas adsorption and adsorbed gas porosity well performance.

Figure 8. Effect of gas slippage and diffusion on well performance with various nanopore sizes between 5 nm to 50 nm.

Figure 9. Effects of the combination effects of gas desorption, adsorbed gas porosity, gas slippage and diffusion on well performance.

(a)   (b)

Figure 10. Comparison of pressure distribution after 30 years with and without considering the combining effects of gas desorption, adsorbed gas porosity, and gas slippage and diffusion [(a) with the combing effects; (b) Without the combing effects].

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(a)

(b)

(c)

Figure 11. Three cases with different natural fracture settings (grey color represents natural fractures) [(a) case 1 with 100 one-set natural fractures; (b) case 2 with 200 one-set natural fractures; (c) case 3 with 200 two-set natural fractures].

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Figure 12. Effects of different number and sets of natural fractures on well performance (NF represent natural fracture).

Figure 13. Comparison of pressure distribution for different cases after 1000 days and 30

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years [(a) base case without NF after 1000 days; (b) base case without NF after 30 years; (c)

case 1 after 1000 days; (d) case 1 after 30 years; (e) case 2 after 1000 days; (f) case 2 after 30
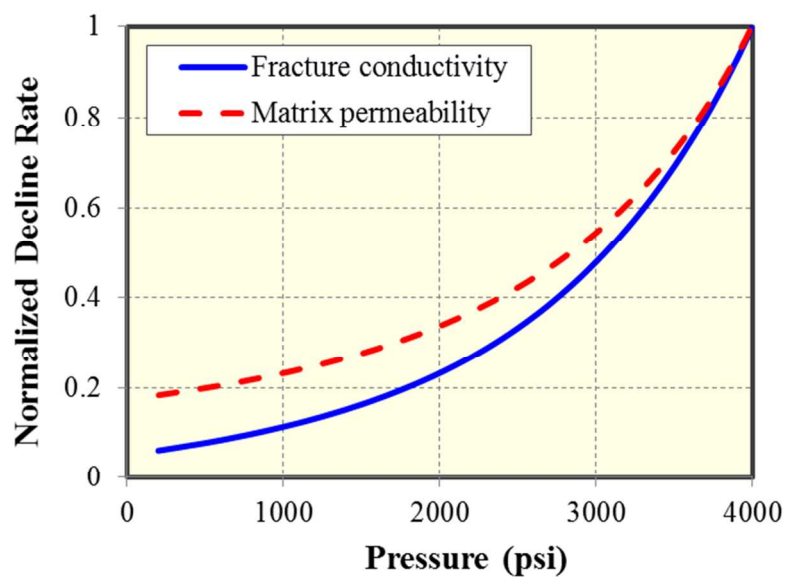
years; (g) case 3 after 1000 days; (h) case 3 after 30 years].

Figure 14. Distribution of fracture width of generated complex non-planar fracture geometry predicted by the fracture model for a synthetic shale-gas case (grey lines represent natural fractures).
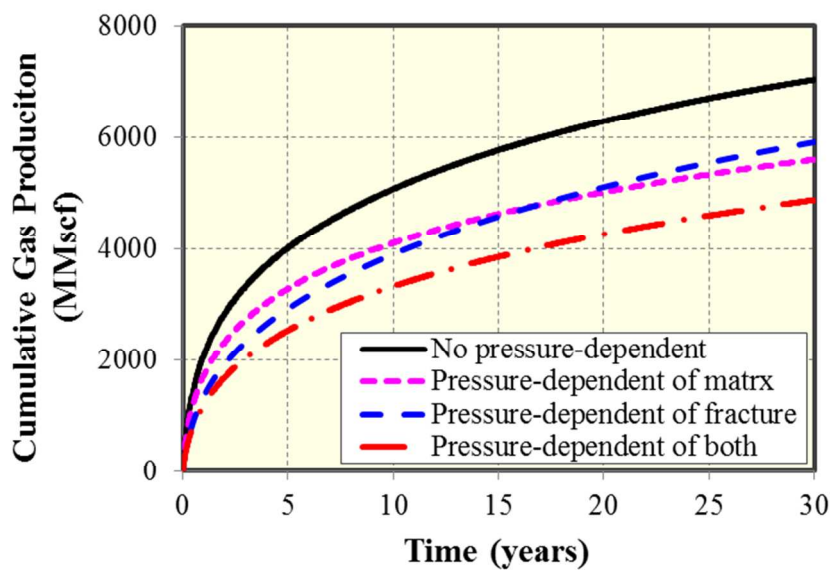
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Figure 15. Complex non-planar fracture geometry with 100 natural fractures in a synthetic
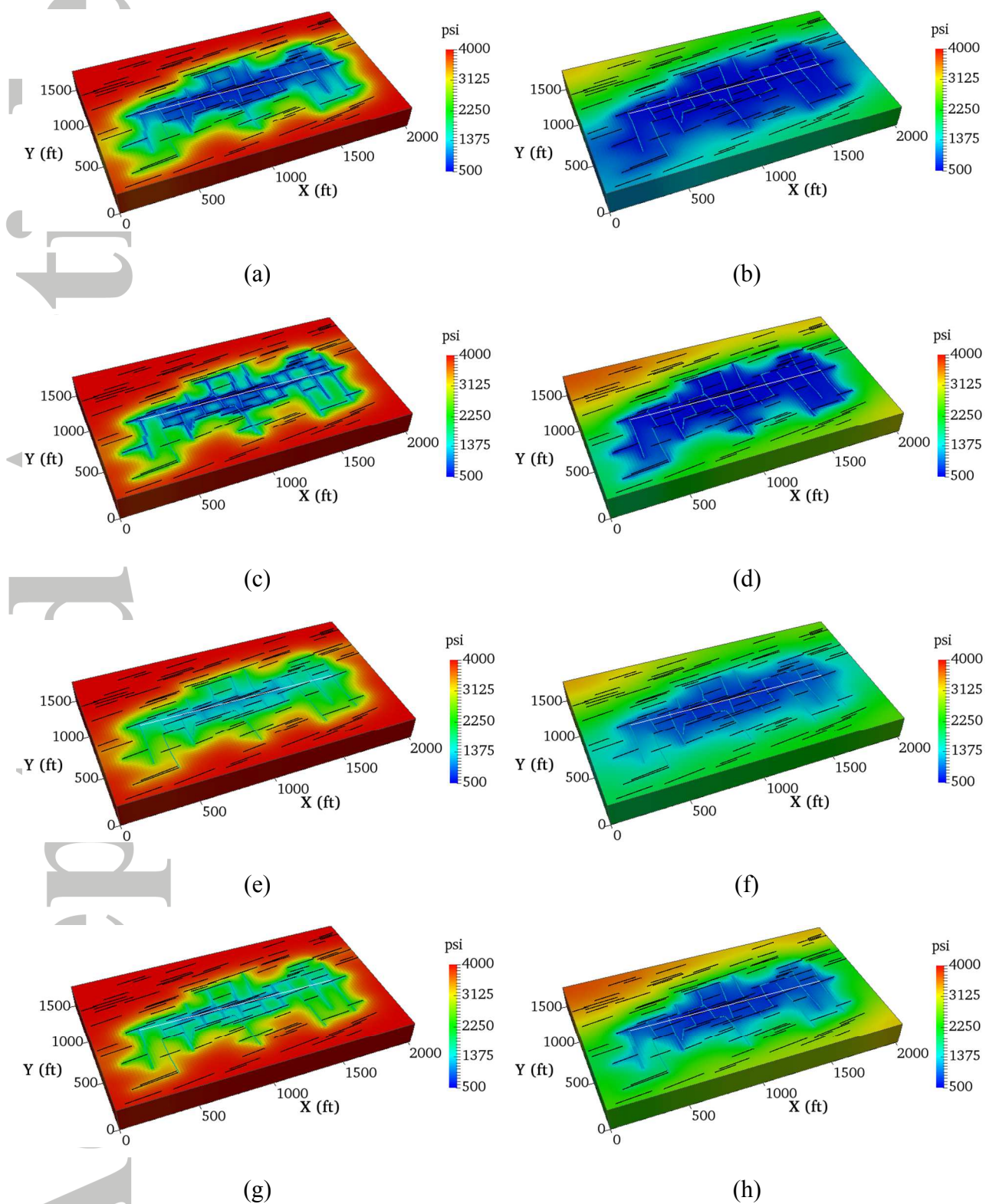
shale-gas case.

Figure 16. Pressure-dependent curves of matrix permeability and fracture conductivity used in this study.
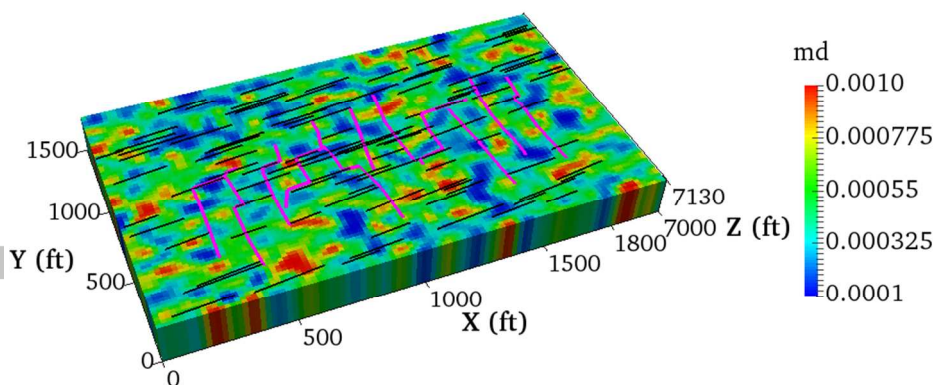
Figure 17. Effects of pressure-dependent matrix permeability and fracture conductivity on well performance.
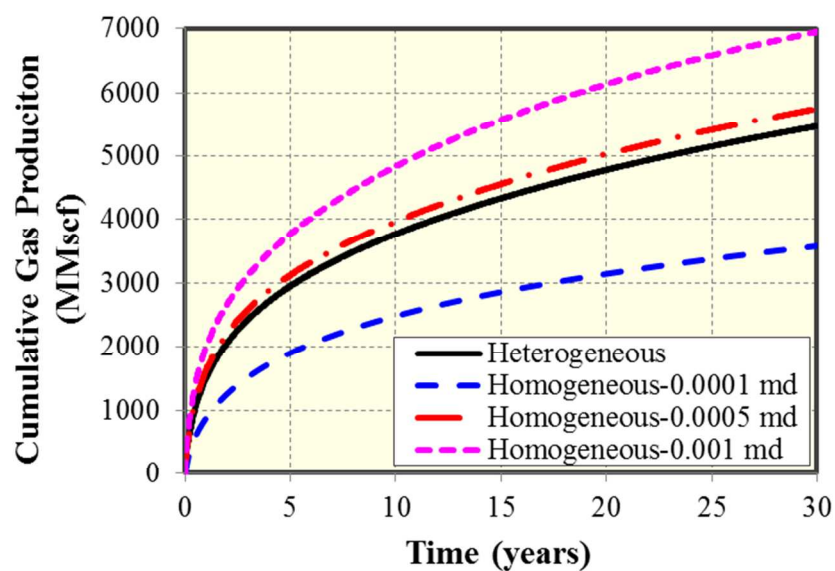
Figure 18. Comparison of pressure distribution for different scenarios after 1000 days and

30 years [(a) without pressure-dependent effect after 1000 days; (b) without pressure-dependent effect after 30 years; (c) pressure-dependent matrix permeability after 1000 days; (d) pressure-dependent matrix permeability after 30 years; (e) pressure-dependent fracture conductivity after 1000 days; (f) pressure-dependent fracture conductivity after 30 years; (g) pressure-dependent of both after 1000 days; (h) pressure-dependent of both after 30 years].

Figure 19. Distribution of matrix permeability in the reservoir with complex non-planar fracture geometry and natural fractures.

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Figure 20. Comparison of well performance between homogeneous and heterogeneous scenarios.

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