SPE-168966-MS

Modeling Analysis of Transient Pressure and Flow Behavior at Horizontal Wells with Multi-Stage Hydraulic Fractures in Shale Gas Reservoirs

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This paper was prepared for presentation at the SPE Unconventional Resources Conference – USAheld in The Woodlands, Texas, USA, 1-3 April 2014.

Abstract

Handling flow through fractured media is critical for transient pressure and flow analysis in shale gas reservoirs, because gas production from such low-permeability formations relies on fractures, from hydraulic fractures and fracture network to various-scaled natural fractures, to provide flow channels for gas flow into producing wells. This study presents a numerical investigation of pressure and flow transient analysis of gas production from a horizontal, multi-staged well in shale gas reservoirs. A specialized three-dimensional, two-phase simulator is developed and used for this purpose, which incorporates known nonlinear flow behavior in shale gas reservoirs. First we discuss a multi-domain, multi-continuum concept for handling multi-scaled heterogeneity and fractures, i.e., using hybrid modeling approaches to describe different types and scales of fractures from explicit modeling of hydraulic fractures and fracture network in simulated reservoir volume (SRV) to distributed natural fractures, microfractures, and tight matrix. Then sensitivity studies of transient pressure responses and flow rates are presented with respect to hydraulic fractures geometry, stimulated reservoir volume (SRV), and natural fracture density. We will also compare the behaviors with two different interporosity flow assumptions, fully-transient and quasi-steady state flow. Unlike conventional reservoirs, their difference cannot be ignored due to the extremely low shale matrix permeability and significant gas compressibility. Specifically, we will analyze a field example from Barnett shale to demonstrate the use of results and methodology of this study.

Introduction

Flow behavior in shale gas and tight gas reservoirs is characterized by single-phase (gas) and/or multi-phase (gas, gas condensate and/or brine) flow and transport in extremely low-permeability, highly heterogeneous porous/fractured, and stress-sensitive rock. The multi-scaled fractures, from hydraulic fractures/network to various-scaled natural fractures provide flow channels for gas flow into producing wells. Therefore, any unconventional reservoir simulator must have the capability of handling fractured media. The published modeling exercises in the literature have paid a lot of attention to model fractures in shale gas formations (e.g., Cipolla, 2009; Freeman et al. 2009a; 2009b; 2010; Moridis et al. 2010; Rubin, 2010; Wu et al. 2012, Wang and Wu, 2013). However, it should be pointed out that there have been very few studies carried out to address the critical issues how to accurately simulate fractured unconventional gas reservoirs or to select the best approach for modeling a given shale gas formation. Many of the modeling exercises use commercial reservoir simulators, developed for conventional fractured reservoir simulation, which have very limited capabilities of modeling multi-scaled or complicated fractured reservoirs. On the other hand, in order to simulate fractured unconventional gas reservoirs, more efforts on model developments are needed from new conceptual models to in-depth modeling studies of laboratory to field scale application.

Double Porosity Model: Double-porosity model is an idealized model, originally proposed by Warren and Root (1963) and as shown in Figure 1. In the double-porosity model, a flow domain is composed of matrix blocks with low permeability, embedded in a network of interconnected fractures. Global flow and transport in the formation occur only through the fracture system, conceptualized as an effective continuum. This model treats matrix blocks as spatially distributed sinks or sources to the fracture system without accounting for global matrix-matrix flow.

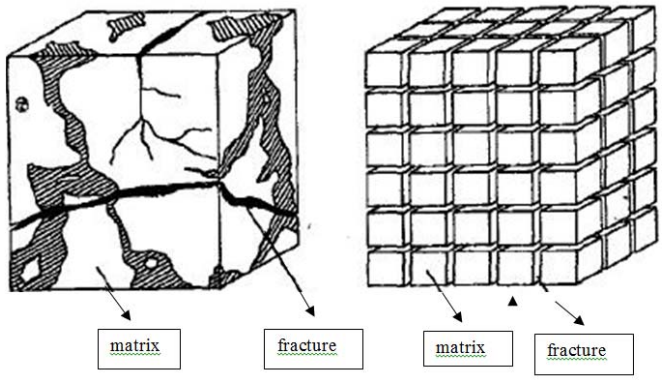

Figure 1 Classic conceptualization for double-porosity model (Warren and Root, 1963)

Multiple-Interacting Continua (MINC): Pruess and Narasimhan (1985) introduced the concept of Multiple-Interacting Continua (MINC) to model heat and multiphase fluid flow in multidimensional, fractured porous media. The MINC concept is able to describe gradients of pressures, temperatures, or concentrations near matrix surface and inside the matrix—by further subdividing individual matrix blocks with one- or multidimensional strings of nested meshes, as shown in Figure 2.6. Therefore, the MINC method treats interporosity flow in a fully transient manner by computing the gradients which drive interporosity flow at the matrix-fracture interface. As a result, the MINC model in general provides a better numerical approximation for transient fracture-matrix interactions than the double-porosity model, when the pressure, temperature or concentration distribution in matrix is hard to reach pseudo-steady state. For shale gas reservoirs, the average fracture spacing could be large and the matrix permeability is extremely low at nano-Darcy. Therefore, matrix pressure distribution may be at transient state most of the time. Compared with the double-porosity model, the MINC concept is more suitable for handling low-permeability fractured unconventional reservoirs. However, the adoption of MINC will be more computational intensive because we need to subdivide the original matrix grid into at least 10 strings of nested meshes and the double-porosity model need only two. In addition, the MINC approach may not be applicable to systems in which fracturing is so sparse that the fractures cannot be approximated as a continuum (Moridis et al. 2010).

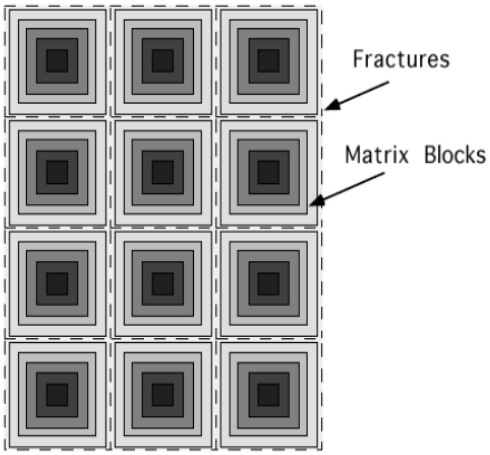

Figure 2 Schematic of MINC (multiple interacting continua) Concept (Pruess and Narasimham, 1985)

Explicit Discrete Fracture Modeling Approach: Explicit discrete-fracture modeling approach (i.e., simulating each of fractures explicitly in the reservoir model) is, in principle, a more rigorous model, as shown in Figure 3. Compared with dual-porosity models, this approach can be applied to disconnected fractured media. In addition, it is suited for the modeling of a small number of large-scale fractures, which may dominate the flow (Karimi-Fard et al. 2004). In the past, the application of this method to field simulation studies of conventional reservoirs has been limited, because of the computational intensity involved, as well as the lack of detailed knowledge of fracture and matrix geometric properties and their spatial distributions at a given subsurface site. However, this approach is very suitable for handling hydraulic fractures, because there are few hydraulic fractures as well as better estimates of their spatial distributions, when compared to natural fractures.

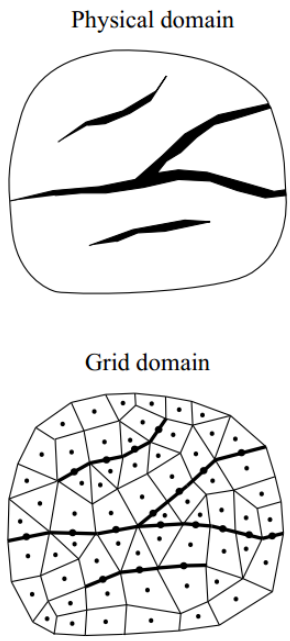

Figure 3 A two-dimensional example of discrete fracture model (Karimi-Fard et al. 2004)

Hybrid-Fracture Model

In our opinion, the hybrid-fracture modeling approach, defined as a combination of explicit-fracture (discrete fracture model), MINC (Pruess and Narasimham, 1985) or the double-porosity model, and single-porosity modeling approaches, seems the best option for modeling a shale gas reservoir with both hydraulic fractures and natural fractures (Wu et. al., 2013). This is because hydraulic fractures, which have to be dealt with for shale gas production, are better handled by the explicit fracture method, and they cannot be modeled in general by a dual-continuum model. On the other hand, natural fractured reservoirs are better modeled by a dual-continuum approach, such as MINC for extremely low-permeability matrix and long lasting transient flow in shale gas formations, which cannot be modeled by an explicit fracture or classic double-porosity model.

Explicit fracture or discrete fracture concept is explicitly to include every fracture in the modeled system using refined grids to discretize fractures and the matrix surrounding fractures. This approach is a good option for simulating hydraulic fractures for gas production from hydraulic fractured wells in a shale gas reservoir. The advantage of this approach is that it can model hydraulic fractures accurately when the fractures are known for their spatial distributions, determined from other fracture characterization studies. The disadvantage is that it cannot be used for simulating natural fractures or micro fractures in general, because the number of natural or micro fractures in a shale gas reservoir is too large for the model to handle and also their spatial distributions are practically unknown.

For the low matrix permeability or large matrix block size, the traditional double-porosity model may not be applicable for modeling natural fractures in unconventional reservoirs. This is because it takes years to reach the pseudo-steady state under which the double-porosity model applies. The MINC concept (Pruess and Narasimham, 1985) is able to describe gradients of pressures, temperatures, or concentrations near matrix surface and inside the matrix–by further subdividing individual matrix blocks with one- or multidimensional strings of nested meshes. Therefore, the MINC method treats interporosity flow in a fully transient manner by computing the gradients which drive interporosity flow at the matrix-fracture interface. In comparison with the double-porosity or dual-permeability model, MINC does not rely on the pseudo-steady state assumption to calculate fracture-matrix flow and is able to simulate fully transient fracture-matrix interaction by subdividing nested-cell gridding inside matrix blocks. The MINC concept should be generally applicable for handling fracture-matrix flow in fractured shale gas reservoirs, no matter how large the matrix block size is or how low the matrix permeability is and is more suitable for handling naturally fractured shale gas reservoirs. However, the MINC approach may not be applicable to systems in which fracturing is so sparse that the fractures cannot be approximated as a continuum.

As Figure 4 shows, in this hybrid-fracture model, both the hydraulic fractures and SRV are evaluated from the microseismic cloud. Recent progresses in microseismic fracture mapping technology provide some useful information to characterize hydraulic fracture growth, stimulated reservoir volume. It documents surprising complexities in many geological environments. Based on the available microseismic data, a primary hydraulic fracture and its associated stimulated volume in each stage can be estimated. The primary fractures are defined first with the orientation and region of the microseismic

clouds. These hydraulic fractures are modeled by the discrete fracture method. Relevant stimulated reservoir volumes (SRV) near the hydraulic fractures are assumed to be natural-fractured and MINC is applied in this area. Single-porosity is applied in the unfractured regions outside the SRV. Local grid refinement (LGR) can improve simulation accuracy, because pressure gradients change substantially over short distances in the regions near hydraulic fractures. LGR is performed near the hydraulic fracture region.

Figure 5 shows how to combine discrete fracture model, MINC method, and single-porosity model to construct grid and physical model to solve a practical problem. We incorporated natural fractures, hydraulic fractures, and SRV. Details information such as how to build the MINC grid and how to locally increase the grid resolution are also introduced

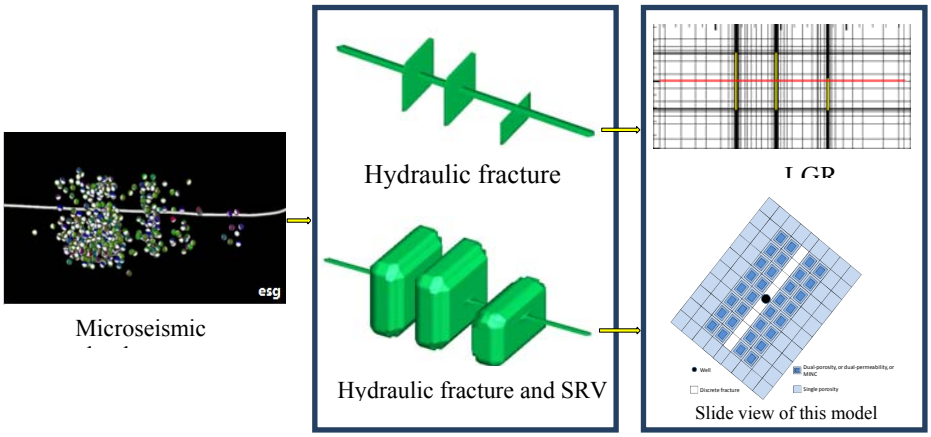

Figure 1 Hybrid-fracture model built methodology from micro-seismic cloud

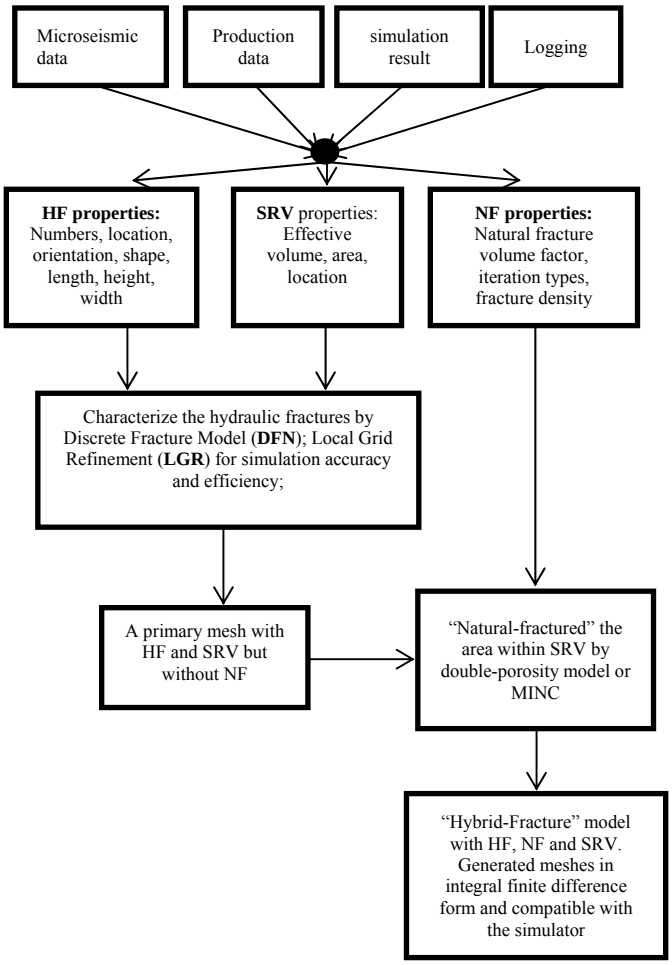

Figure 2 Methodology to combine discrete fracture model, MINC method, and single-porosity model to construct grid and physical model to solve a practical problem

Applications

This example presents applications of the unconventional reservoir simulator (Wu et al. 2013) to quantify hydraulic fractures in shale gas reservoirs using transient pressure data. Modeling studies in this part indicate that the most sensitive parameter of hydraulic fractures to early transient gas flow through extremely low permeability rock is actually the fracture-matrix contacting area, generated by fracturing stimulation. Based on this observation, it is possible to use transient pressure testing data to estimate the area of fractures generated from fracturing operations. We will conduct a series of modeling studies and present a methodology using typical transient pressure responses, simulated by the numerical model, to estimate fracture areas created or to quantity hydraulic fractures with traditional well testing technology. The type curves of pressure transients from this study can be used for quantify hydraulic fractures in field application.

The primary flow regime observed in a fractured tight/shale gas well is approximated as linear flow, which may continue for several years. Wattenbarger et al. (1998) gave the "short-term" approximations for this linear flow with constant rate, respectively,

$$m_{Di} - m_{Dwf} = \frac{200.8Tq_gB}{\sqrt{(\phi\mu c_t)_i}\sqrt{k}A}\sqrt{t} \qquad (1)$$

where m_D is the notmalized pseudo pressure; $q_g$is the gas rate; B is the gas formation volume factor; □ is the formation porosity; c_t is the total compressibility, k is the formation permeability; A is the hydraulic fracture area and t is the time; subscript i refers to initial condition, and subscript wf refers to the wellbore condition;

Equation (1) indicates that for the constant-flowing-rate boundary condition, linear flow is characterized by a straight line on the plot of normalized pseudo pressure vs. the square root of time. The slope of this square-root-of-time plot provides some useful information for estimate the hydraulic fracture area. The accuracy of this estimation is influenced by initial pressure, formation average permeability and total compressibility (Nobakht and Clarkson, 2012).

Below is a detailed discussion of this linear flow model, based on the simulation results. First, 3 fracture models with different fracture numbers, shapes but the same fracture-matrix contacting areas are simulated. Results show that the most sensitive parameter of hydraulic fractures to early transient gas flow through extremely low permeability rock is actually the fracture-matrix contacting area, generated by fracturing stimulation. Then gas adsorption and natural fracture systems around the hydraulic fracture are also studied on this model.

Different Fracture Numbers and Shapes: Figure 6 (a, b, c) are two-dimensional sketches for the three models, mentioned above. In these figures, black lines represent the hydraulic fractures in the reservoir of size of $\mathbf{100m \times 10m \times 10m}$. Horizontal wells are shown in these figures as well. But it ignores flow between reservoirs and horizontal wells. Only the flow from hydraulic fractures supports well production.

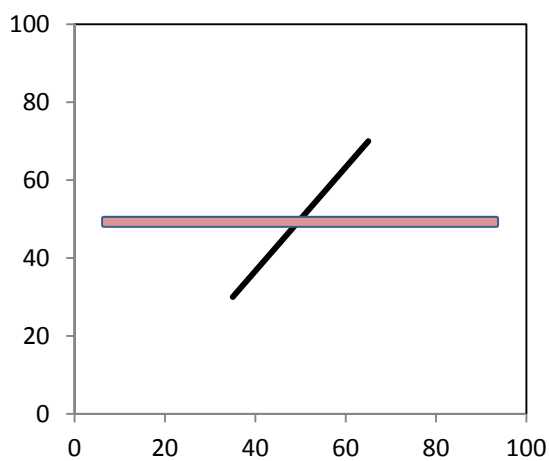

Figure 6(a) Single hydraulic fracture diagonal to XY direction

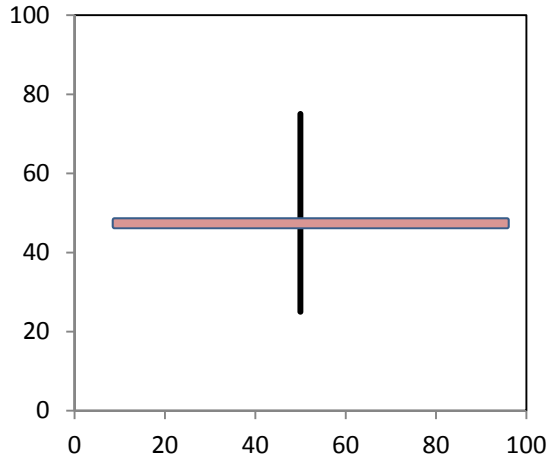

Figure 6(b) Single hydraulic fracture othogonal to XY direction

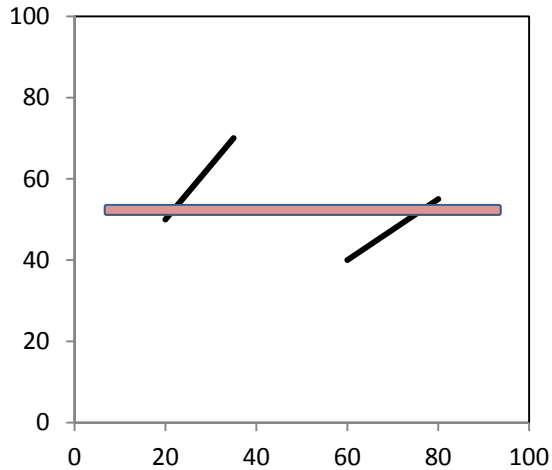

Figure 6(c) Two hydraulic fractures diagonal to XY direction

Figures 7, 8 and 9 show the grids generated for the above three fracture models. Units for X and Y coordinates in these figures are meters. A corse grid system is built with rectangular grids at initial and local grids refinement technology is then applied to better describe the area near hydraulic fractures. Grids that intersect with hydraulic fractures are continuely refined until the grid sizes are small enough to be in the same order of magnitude with fracture width. This grid-refining process enables us to accurately describe flow characteristics near the hydraulic fracture region and gurantee the efficiency and accuracy of simulation results.

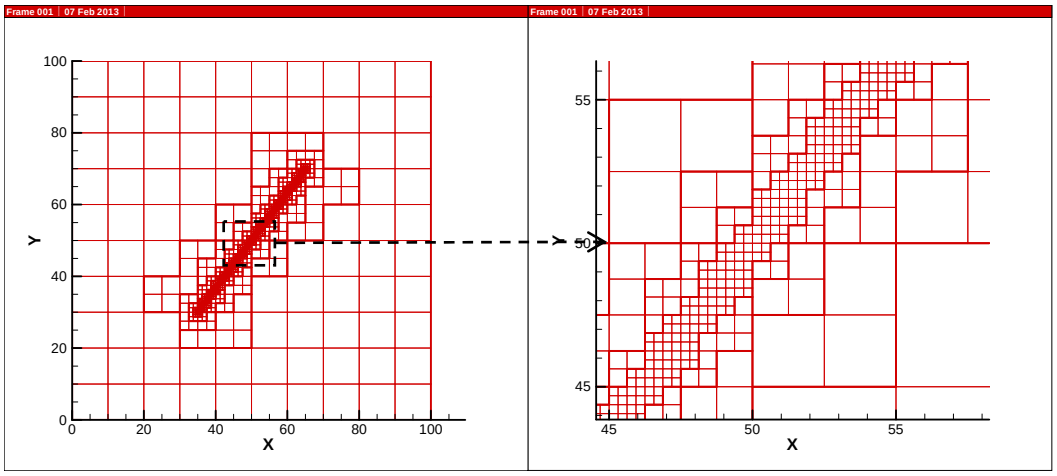

Figure 7(a) Refine grids for Figure 5.1(a) **Figure 7(b) Local zoom in for Figure 5.1(a)**

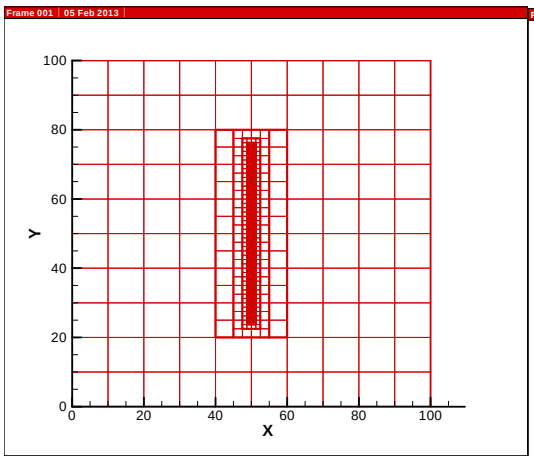

Figure 8 Refine grids for Figure 5.1(b)

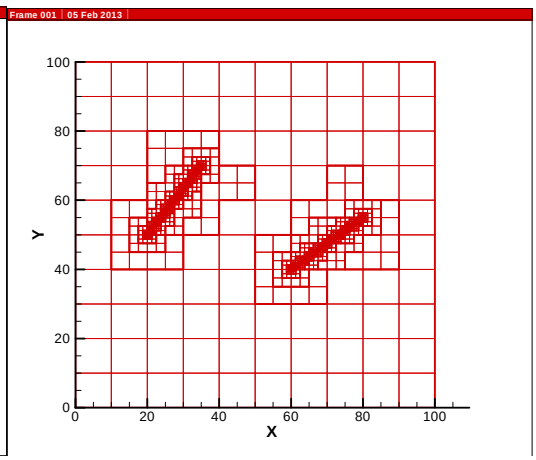

Figure 9 Refine grids for Figure 5.1(c)

Table 1 Input parameters for simulating the above three models

Parameters	Value	Units
Temperature	581.4	^{o}R
Production rate	133.66	MSCF/D
Matrix permeability	3.24×10^{-5}	mD
Fracture permeability	1.0×10^{5}	mD
Gas viscosity	1.84×10^{-2}	cp
Porosity	0.05	
Gas compressibility	2.8×10^{-4}	psi^{-1}
Rock compressibility	0	psi^{-1}
Initial pressure	3,100	psi
Fracture length	164.0	ft
Fracture width	0.033	ft

Table 1 lists the input parameters for simulations used in the above three fracture models. Fluid in this study is ideal methane gas, which indicates that the gas Z factor always remains 1 and viscosity is a constant. Using the parameters in the table, the dimensionless hydraulic fracture conductivity is calculated as $C_{fd} = K_f w_f / K_m w_m$ and the hydraulic fracture could be treated as infinite conductivity (Cinco-Ley and Samaniego, 1981). In simulation, only one discrete grid is used to represent one stage of hydraulic fracture. Figure 10 shows the calculated hydraulic-fracture pseudo-pressure vs. square root of time for these three models. Calculation results all follow the straight relation between pseudo-pressure and square root of time as shown in Figure 10. Besides, they almost coincide with each other regardless of their fracture number and shape. This phenomenon indicates that fracture number and shape have little influence on the early transient pressure behavior for linear flow. The linear flow Equation 1 for single fracture can be extended to multi-stage fractures and slant fractures to estimate their fracture properties such as effective contact area.

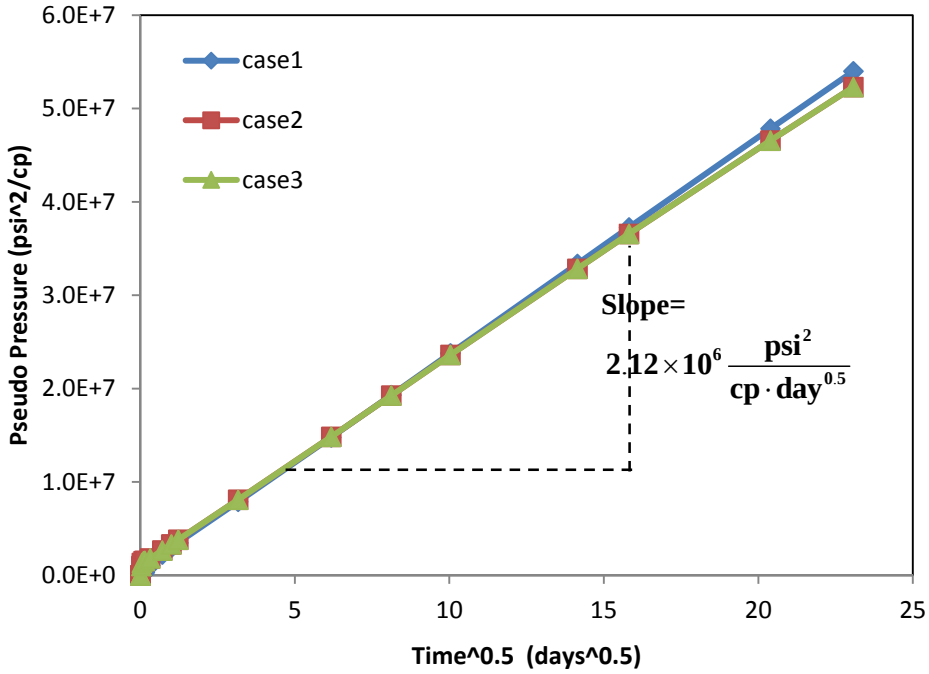

Figure 10. Fracture pseudo-pressure vs. square root of time for the three models

From Equation (1), fracture-matrix contact area can be estimated the Equation (2).

$$S=\frac{200.8Tq_g}{m_{cr}\sqrt{k\left(\phi\mu c_t\right)_i}} \tag{2}$$

where m_{cr} is the slope of straight line in pseudo-pressure vs. square root of time. Substitute the calculated m_{cr} and other parameters listed in Table 5.1, the calculated fracture-matrix contact area from Equation (2) is estimated as $1.1526\times10^4\ ft^2$, while the simulation input about the fracture-matrix contact area for these three models is $1.0724\times10^4\ ft^2$. Considering the gas compressibility in the numerical simulation process cannot be kept constant, 7% error between the formulation analysis and real input data is acceptable. This match between analytical results and numerical results give confidence on grids refinement technology used, unconventional simulator formulation and pseudo-pressure calculation.

Field Example Simulation of History Matching

In this example, the unconventional gas reservoir simulator is used to study a field case. The field data for this simulation is the pressure and production rate profiles. They came from a multi-stage stimulated horizontal well in Barnett shale play. This field data is provided by Dr. Ozkan (2010) for this case study. Figure 11 shows the pressure and production rate data for three years.

Apart from the pressure and production rate data, the gas company also measures and provides some useful information about this reservoir, such as the initial pressure, average porosity, gas saturation and so on. They are shown in Table 2. However, these data are not enough for the simulation and some other important parameters need to be estimated. Without the support of enough field data, gas adsorption, Klinkenberg effect and geomechanics effect are not considered in this case.

Brown and Ozkan (2009) analyzed the same data and they plotted the rate-modified pseudo pressure responses as a function of the square root of time, as shown in Figure 12. It shows that "hydraulic fracture and matrix" linear flow takes the main part in the early time because linear relation is observed between the above two. Its slope is $7733\frac{psi^2 d^{1/2}}{cp\cdot Mscf}$.

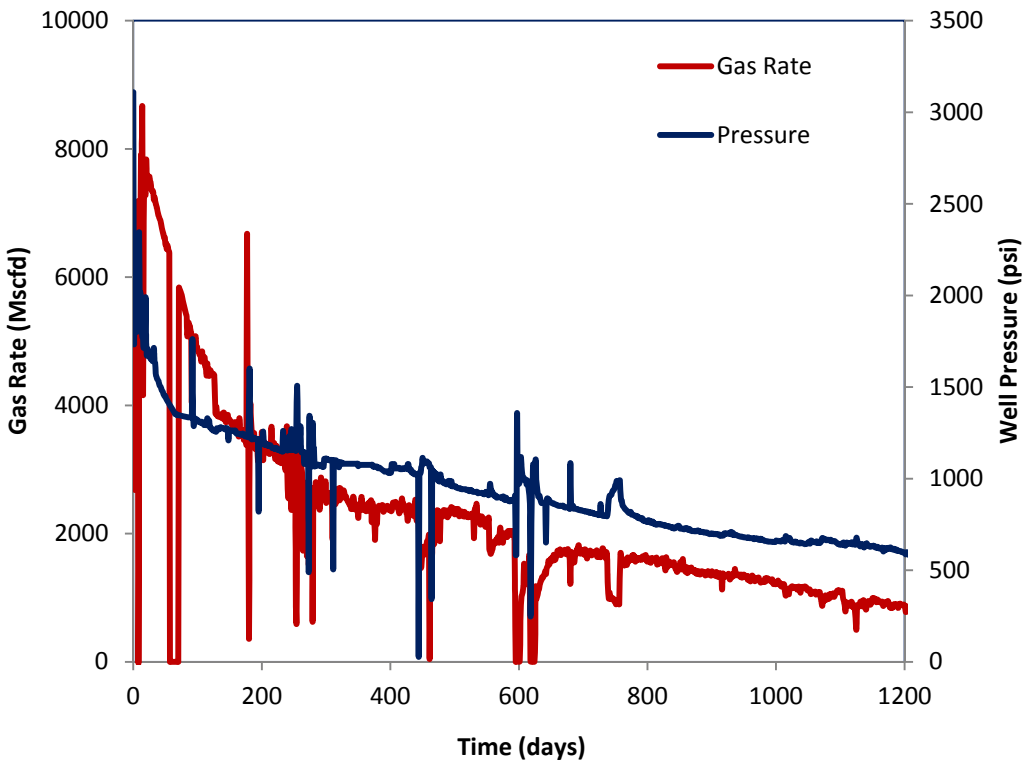

Figure 11 Daily pressure and production rate profiles from the field data

Table 2 Raw data from the company	
Initial pressure, p_i, psia	3,109
Formation thickness, ft	300
Formation temperature, T, ^{o}F	106
Well radius, r_w, ft	0.23
Number of hydraulic fractures	19
Horizontal well length,L,ft	3,250
Matrix porosity, Φ_m	0.04
Fracture half-length, X_f, ft	275
Specific gravity, γ	0.588
Gas saturation, S_g	0.9
Water saturation, S_w	0.1

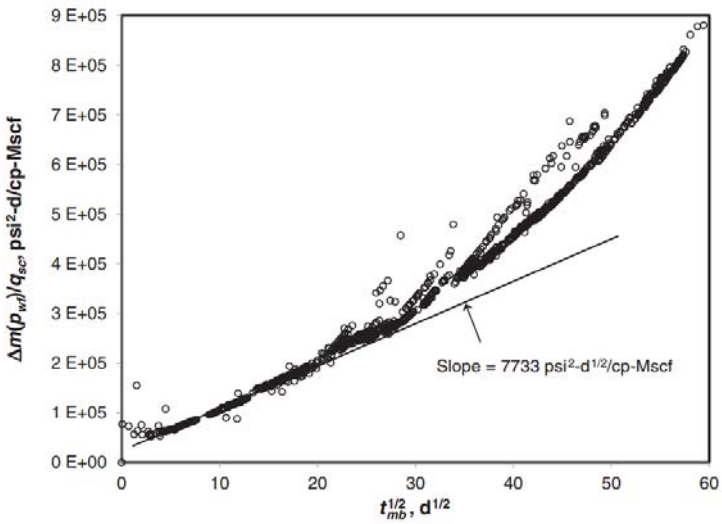

Figure 12 Linear-flow analyses of the field data

All the hydraulic fractures are assumed to fully penetrate the studied formation in the vertical direction and SRV is the area within 30 meters from the hydraulic fractures. Similar with the last case, only one set hydraulic fracture and its surrounding area are simulated. Refined grid and the sketch show of this area are shown below:

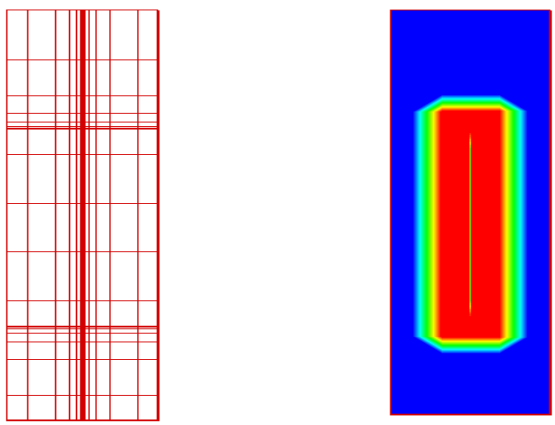

Figure 13 Refined grids for the field case study and model sketch

The curve of wellbore pressure with time in the first 240 days is input as a calculation data, as shown in Figure 5.14. With the well-built model, calculated production rate is compared with the real data. They matched very well to each other and thus our simulation model about the unconventional gas reservoir can be applied to the real data analysis and economics forecast (Figure 15).

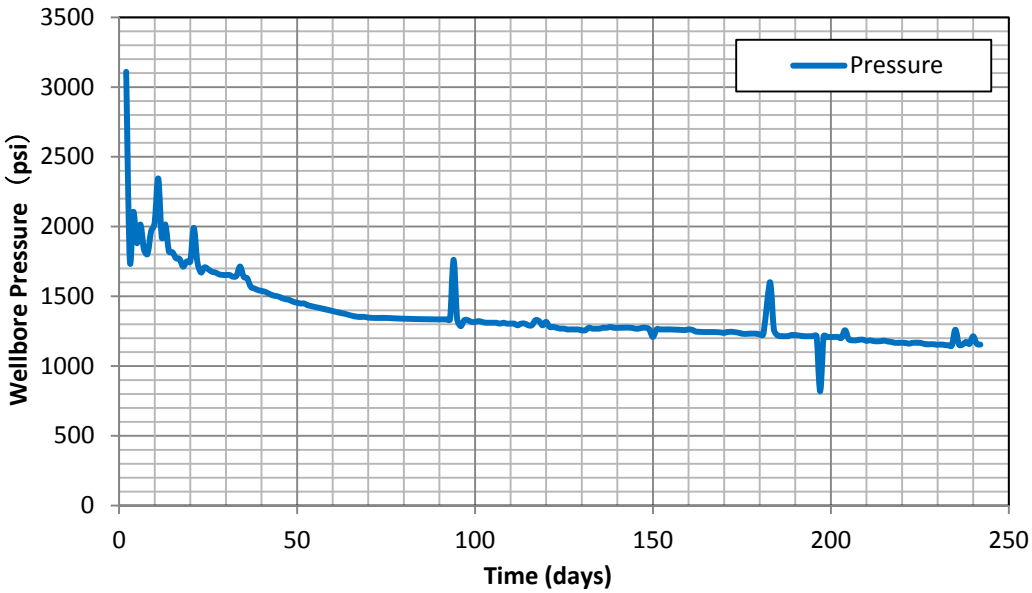

Figure 14 Wellbore pressure data in the first 240 days for calculation

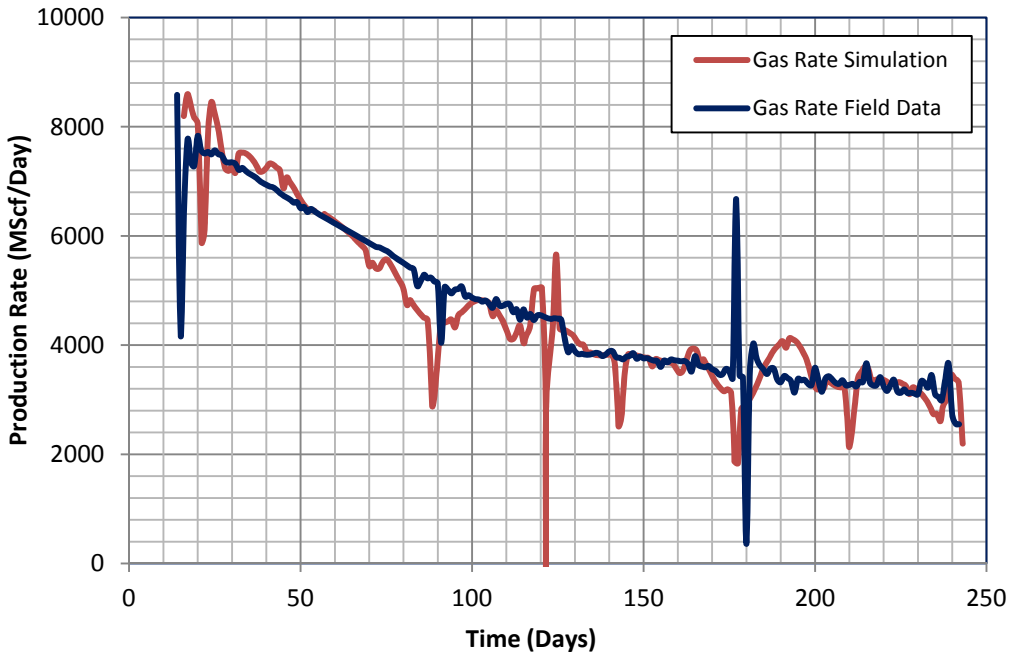

Figure 15 Calculated and field recorded production rate comparision

Conclusions

We proposed a hybrid-fracture conceptual model to characterize the complex fracture system in unconventional reservoirs. Discrete fracture model is adopted to simulate the hydraulic fractures, dual-continuum model or effective continuum model for the near-hydraulic-fracture, natural-fractured SRV area and using single porosity model for the unfrcatured area outside SRV. An effective methodology is built for this hybrid-fracture model to run in our simulator including the pre-process and post-process parts. Grid refinement technology is introduced to accurately simulate the non-regular hydraulic fractures. This approach is verified by comparing with the "fracture-matrix" linear flow analytical solutions. Further study based on this grid refinement technology indicates that hydraulic fracture total contact area within matrix is the main parameter that influences early flow behavior regardless of the hydraulic fracture number and shapes as long as the total areas are the same. Associated with the analytical results, the total fracture-matrix contact area and SRV volume can be estimated. A field application example with data history matching is carried out in this study. With the input of daily pressure profile and relevant adjusted formation information, the calculated production rate matched pretty well with the field-recorded production rate data. It indicates this simulator is able to handle field simulations. This matched simulation result also helps us to better understand in this shale plays that "fracture-matrix" linear flow is a critical role in production and there does exist a SRV around the hydraulic fractures.

Acknowledgement

This work was supported in part by EMG Research Center in Colorado School of Mines, CNPC-USA, and Fundation CMG. Thanks are also due to Dr. Ozkan for providing the field production data for our modeling studies.

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