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Integrated reservoir flow and geomechanical model to generate type curves for pressure transient responses of a hydraulically-fractured well in shale gas reservoirs

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A B S T R A C T

Shale gas reservoirs have ultra-low matrix permeability and consist of matrix and natural fracture systems. Horizontal wells with hydraulic fractures are necessary to economically exploit shale gas reservoirs. Due to these complex features of shale gas reservoirs, understanding pressure transient characteristics is of importance. Through coupling of flow and geomechanical models for well/reservoir/hydraulic fracture systems, a new approach has been established to predict the pressure transient behavior and to generate type curves. To account for geomechanical effects with stress dependent permeability, linear elastic geomechanical models and two stress dependent permeability correlations, exponential and power law correlations, from previous experimental researches were implemented in the reservoir model. A number of cases considering a geomechanical model, exponential correlation, and power law correlation were compared. These processes showed roughly a 1–5% variation of productivity in shale gas reservoirs. Based on the extensive numerical simulations with the updated model, a series of type curves were developed in terms of dimensionless pseudopressure and derivative of dimensionless pseudopressure versus dimensionless time considering various reservoir and fracture properties. Using the type curves as a guide, we then presented flow regimes that are expected for different values of geomechanical properties, number of fractures, length of the fractures, spacing between fractures, and properties of stimulated reservoir volume (SRV). Using the characteristics of new dimensionless parameters and the developed type-curve set, a simple and practical procedure was presented to estimate reservoir properties in multi-fractured horizontal wells. Application of type curve matching to synthetic data was shown to be useful in estimating effective fracture and matrix permeability and porosity. A history match of a field example in Barnett Shale data indicates that the model with stress-dependent properties matches the actual production data better than the model with constant properties. This study provides insight into the characteristics of a hydraulically-fractured horizontal well, and the newly developed type curves yield more unique and accurate results.

1. Introduction

Because conventional reservoirs with high permeability have been gradually depleted, unconventional resources in low permeability reservoirs are presently receiving increasing attention. In particular, techniques such as horizontal drilling and multi-stage hydraulic fracturing have allowed economic production of gas from shale gas reservoirs, which have the potential to supply the world with an enormous amount of energy (Browning et al., 2013; Gulen et al., 2014).

Shale gas reservoirs have characteristic features dissimilar to those of conventional reservoirs. A shale matrix has extremely low permeability ranging from 1 to 100 nd. Typically, shale gas reservoirs have narrow thickness with infinite lateral extension and include conductive natural fractures, which substantially influence well performance (Cipolla et al., 2010). To develop these reservoirs, a multi-fractured horizontal well is necessary. Hydraulic fractures improve the conductivity of rock and horizontal wells to increase production by extending the contact area of wellbore (Zhang et al., 2014). In shale reservoirs, hydrocarbon gas is composed of both free and adsorbed gas. Free gas exists in the matrix and fracture pore system and adsorbed gas exists on the surface of organic materials. When hydraulic fracturing induces stress and strain changes, the natural fracture is rejuvenated and stimulated reservoir volume (SRV), which is conductive network of fractures in the drainage volume, is generated. However, conductivity of this fracture network is sensitive to the changes in stress and strain

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during production because of stress corrosion affecting the proppant strength, crushing, and embedment into the formation (Ghosh et al., 2014). Therefore, geomechanical effects during production must be included to simulate the shale gas reservoir accurately. Because of these features, shale gas reservoirs show a long transient flow period and have intricate flow regimes. Therefore, understanding pressure transient behavior of a hydraulically fractured horizontal well in a shale gas reservoir is important to provide insight into long-term production performance as well as to present criteria for the estimation of reservoir properties.

Because of the horizontal well and hydraulic fractures, pressure transient flow is complicated (Cheng, 2011). Many researchers have investigated the analytical models of a multi-fractured horizontal well. Pressure transient behavior of a hydraulically-fractured horizontal well was studied by Larsen and Hegre (1991, 1994) and Horne and Temeng (1995). The effects of number, position, and direction of fractures on pressure transient responses were discussed by Raghavan et al. (1997) in high permeability, conventional reservoirs.

To analyze pressure transient behavior, type curves are presented by previous studies with various reservoir-well systems. Type curves based on pressure derivatives were suggested by Tiab and Crichlow (1979), who used the pressure derivative to aid in fault detection. Tiab and Kumar (1980) presented type curves based on the derivative of dimensionless pressure for analyzing well test data. Barua et al. (1985) used a nonlinear least-squares technique for matching the pressure and pressure derivative data by including the analytical solutions of Warren and Root's dual porosity model (1963). Thompson and Temeng (1993) presented details on a nonlinear regression technique to interpret pressure transient data from a drawdown or buildup test on a horizontal well.

Recently, as shale gas reservoirs have received attention, researches on pressure transient behavior have been actively discussed. Medeiros et al. (2007) presented a discussion of diagnostic pressure and pressure derivative plots for hydraulically fractured horizontal wells in locally and globally fractured formations. Cheng (2011) researched the pressure transient behavior of a horizontal well with hydraulic fractures using a numerical simulation model with consideration of various factors in a range practical to Marcellus Shale. Wu et al. (2012) studied a numerical model for transient gas flow behavior and its application to well testing analysis in unconventional gas reservoirs, which include realistic reservoir gas flow processes in a hydraulically fractured vertical well. Rana and Ertekin (2012) presented a new set of type curves for pressure transient analysis of composite dual porosity systems. Lee et al. (2014) addressed pressure transient analysis for horizontal wells in shale gas reservoirs incorporating a number of important formation properties and nonlinear processes. Kim et al. (2013) presented a comprehensive reservoir simulation model to investigate the characteristics of pressure transient responses under the influences of hydraulic fracture properties and a nonlinear gas flow mechanism. They provided various type curves in terms of dimensionless pseudopressure and time for transient pressure responses and conducted type-curve matching for synthetic pressure data.

Several papers studied decreasing fracture conductivity depending on reservoir stress. Pedrosa (1986) presented the permeability modulus, which measures the exponential dependency of permeability on pressure to construct type curves from stress-sensitive reservoirs. Tran et al. (2005) proposed several modeling methods for coupling geomechanics to fluid flow in the reservoir. Among several methods, iterative coupled approach has proven to be the most effective approach. This coupling is performed through the use of a specially defined porosity in the reservoir simulator. Raghavan and Chin (2004) showed numerical model with three stress-dependent permeability correlations in an isotropic, linear elastic model. Dong et al. (2010) presented experimental results for this effect. They measured the stress-dependent porosity and permeability. They showed that the data can be fitted by using an exponential correlation and a power law correlation. Cho et al. (2013) presented the effect of pressure-dependent natural fracture permeability with experiments for Bakken-shale core samples and a history matching process.

Even though various studies have been conducted for analyzing pressure transient response of shale gas reservoirs, research considering geomechanical effects of shale gas reservoirs is insufficient. Previous researches have considered only pressure-dependent exponential correlation without geomechanical models. In this paper, to simulate constitutive behavior of reservoir rock, a linear elastic model is applied. Stress-dependent exponential and power law correlations based on experimental data (Dong et al., 2010) are used to calculate stress-dependent porosity and permeability during production. To analyze pressure transient characteristics of a hydraulically fractured horizontal well in shale reservoirs, extensive numerical simulations, including geomechanical mechanisms, were conducted. A number of cases considering geomechanical models, exponential correlation, and power law correlation were compared. Discussions were made regarding the impacts of various reservoir types and stress-dependent properties upon the sequence of flow regimes that could be encountered for shale gas reservoirs. Based on the extensive numerical simulations with the updated model, a series of type curves were developed in terms of dimensionless pseudopressure drop and derivative versus dimensionless time with respect to various reservoir and fracture properties. Using the type curves as a guide, we presented the flow regimes that are expected for different values of experimental coefficients for exponential and power law correlations, initial effective stress, initial reservoir pressure, natural fracture permeability, matrix porosity, Young's modulus, and Poisson's ratio. Using the developed type curve sets, a simple and practical procedure was presented to estimate reservoir properties in multi-fractured horizontal wells. Barnett Shale production data is used to verify the proposed model with stress-dependent properties by a history matching technique.

2. Theory

2.1. Adsorption

Previous researchers reported that adsorption of methane may constitute 5–30% of the total gas production in shale gas reservoirs (Cipolla et al., 2010; Mengal and Wattenbarger, 2011; Thompson et al., 2011). The most commonly used adsorption/desorption model is a Langmuir isotherm, which assumes that there is a dynamic equilibrium at constant temperature and pressure. Adsorption capacity of a rock is described as a function of pressure changes under isothermal conditions:

$$V(p) = \frac{V_L p}{p + p_L}, \tag{1}$$

where the Langmuir volume, V_L, indicates the maximum gas volume can be adsorbed, and the Langmuir pressure p_L is the pressure at which half of the Langmuir volume gas is stored.

2.2. Non-Darcy flow

In the propped hydraulic fractures, turbulent gas flow caused by high gas flow velocity occurs. To describe this flow, non-Darcy