International Journal of Coal Geology 146 (2015) 79–90

Contents lists available at ScienceDirect

International Journal of Coal Geology

journal homepage: www.elsevier.com/locate/ijcoalgeo

A comprehensive model to history match and predict gas/water production from coal seams

Ahmed Farid Ibrahim *, Hisham A. Nasr-El-Din

Texas A&M University, Harold Vance Department of Petroleum Engineering, College Station, TX, USA

A R T I C L E I N F O

Article history:
Received 7 January 2015
Received in revised form 7 May 2015
Accepted 7 May 2015
Available online 15 May 2015

Keywords:
History matching
Prediction
Coalbed methane
Coal shrinkage

A B S T R A C T

Coalbed methane (CBM) currently accounts for approximately 5% of U.S. annual gas production. The performance prediction of CBM is very complex. It is highly affected by the complexity of porosity–permeability variation, reduction due to formation compaction, enhancement due to matrix shrinkage, and the two-phase flow effects. An additional complexity is added if the initial gas content, permeability, and porosity are not available. In this paper an integrated model was developed to simulate the behavior of CBM. A developed generalized material balance equation is used to account for the solubility of the methane in water, and the changes of porosity and permeability with pressure depletion. The equation is formatted similarly to the conventional material balance of oil reservoirs.

An optimization algorithm was also used with the integrated model. The model could be used as a history matching tool to estimate the original gas-in-place (the adsorbed gas-in-place and the free gas-in-place), the initial formation permeability, the gas and water relative permeability exponents, and the matrix shrinkage coefficient that reflected the permeability changes.

The developed model was validated by use of different simulation cases generated with a commercial simulator. The results show a good match between the simulation cases and the integrated model. The model was then used to analyze the production data of different CBM formations (the Fruitland and the Upper Pottsville Formations, USA). The model was used to match the production history data (gas and water rates) in order to estimate the gas-in-place and the formation properties. These parameters were then used to predict the production performance. The model can be run with different production control conditions such as the constant water rate or the constant bottom-hole flowing pressure.

This model could be used as a helpful tool in CBM investment and development. It can also be used to obtain the key reservoir parameters for newly discovered reservoirs such as gas-in-place, initial water-in-place, water production rate, gas production rate, and the peak gas rate. With this information, an investor will better determine the feasibility of a project. Also, this model can be used to optimize the dewatering rate (initial water production rate) in order to optimize the time taken to reach the peak gas rate.

1. Introduction

According to the U.S. Energy Information Administration (EIA), coalbed methane production in the U.S. in 2013 was 1.5 Tscf, nearly 5% of U.S. gas production that year (EIA, 2013). The CBM is considered an unconventional resource where the coal is the source rock and the reservoir rock for the methane (Gray, 1987). The performance prediction of CBM reservoirs are challenging due to the complex interactions of storage and transportation mechanisms. The coalbed formations are characterized by their dual porosity: primary (micropores and macropores) and secondary (cleats network) (Laubach et al., 1998). The main difference between conventional reservoirs and the CBM is that in CBM the primary porosity system contains the majority of the gas-in-place as adsorbed gas in the coal matrix, while the cleat network system is usually full of water and it provides the path for mass transfer to the wellbore (Laubach et al., 1998; Shi and Durucan, 2004). As a result, the production behavior of the CBM formations greatly differs from conventional gas reservoirs (Gray, 1987). The production of CBM formations contains three stages (Ahmed and Meehan, 2012; Gray, 1987). In the dewatering stage, the water produces from the formation and the pressure in the cleat network decreases, which allows gas to desorb from the coal matrix. Once the gas saturation in the cleat network becomes higher than the critical gas saturation, it begins to flow through the cleat network to the producing wells. As the gas desorption from the matrix continues, the gas flow increasing becomes more dominant and it reaches its maximum value (peak gas stage). Finally, in the decline stage, the gas flow decreases and the CMB behavior becomes similar to the conventional gas reservoirs. Also, as the gas desorbs from the coal surface the matrix shrinks. Matrix shrinkage increases

* Corresponding author. Tel.: +1 979 9973321.
E-mail address: ahmed.ibrahim@pe.tamu.edu (A.F. Ibrahim).

http://dx.doi.org/10.1016/j.coal.2015.05.004
0166-5162/

cleat width, and the permeability increases (Harpalani and Schraufnagel, 1990).

This complicated behavior of CBM limits the use of common methods, such as decline curves, to predict the gas recovery and the well performance. Some of these decline curves analyses assume constant operating conditions and static reservoir behavior, which are usually violated, that leads to incorrect results (Arps, 1945). Clarkson explained that CBM wells violate many of the conditions for Arps decline curve analysis (Clarkson, 2013). In CBM wells, the Arps b-exponent is not constant during the decline stage. The early performance decline often appears to have exponential decline but in the end becomes more hyperbolic. As a result, the uses of the Arps exponential model early in the production history tended to underestimate gas reserves (Clarkson, 2013). Also some of these decline curves faces some difficulties in fitting models with higher number of unknowns. The numerical reservoir simulators are therefore the best tools for predicting the performance of the CBM reservoirs. The prediction of gas production can be time consuming, expensive, and it can become unreliable if the formation parameters are unavailable. Analytical models and history matching can be used efficiently to estimate the reservoir parameters and predict production performance.

The Material Balance Equation (MBE) describes the production behavior of the oil and gas reservoirs. Material balance equations are used to define the performance of oil and gas reservoirs. For conventional oil reservoirs, it has the following form:

$$\mathbf{N}(\mathbf{B_t}-\mathbf{B_{ti}})+\mathbf{G}(\mathbf{B_g}-\mathbf{B_{gi}})+\mathbf{NB_{ti}}\left[\frac{\mathbf{c_w\,s_{wi}+c_f}}{1-\mathbf{s_{wi}}}\right]\Delta\overline{\mathbf{P}} = \mathbf{N_p}\left[\mathbf{B_t}+\mathbf{B_g}(\mathbf{R_{po}}-\mathbf{R_{soi}})\right] \tag{1}$$

And for gas reservoirs,

$$\mathbf{G}(\mathbf{B_g}-\mathbf{B_{gi}})+\mathbf{GB_{gi}}\left[\frac{\mathbf{c_w\,s_{wi}+c_f}}{1-\mathbf{s_{wi}}}\right]\Delta\overline{\mathbf{P}} = \mathbf{G_pB_g}+\mathbf{W_pB_w} \tag{2}$$

To derive these equations, it is assumed that the reservoir temperature is constant; there is equilibrium reservoir pressure (the porosity, the permeability, and the fluid saturations are the same throughout the entire reservoir); there is a constant reservoir bulk volume; the fluid and reservoir rock are nonreactive; and reliable production, pressure and the pressure-volume-temperature (PVT) data are available (Craft et al., 1959).

Various forms of MBEs for CBM and shale gas formations have been developed (Ahmed and Meehan, 2012; Clarkson and McGovern, 2001; King, 1993; Seidle, 1999; Williams-Kovacs et al., 2012). These equations account for the assumptions of the material balance equation for conventional reservoirs with considering the adsorbed gas. Also, it assumes equilibrium between the free gas in the pores and the adsorbed gas on the matrix. These equations account for the formation compressibility and the fluid compressibility effects; however, they do not account for matrix shrinkage and methane-in-water solubility.

Different authors discussed the effect of matrix shrinkage on formation permeability, especially when the formation pressure is depleted (Clarkson et al., 2010; Harpalani and Schraufnagel, 1990; Liu and Harpalani, 2013; Palmer, 2009; Shi and Durucan, 2005). The gas desorption shrinks the coal matrix and increases cleat width, which in turn increases the absolute permeability. Also, matrix shrinkage improves relative permeability to gases. As the volume of cleat network increases, while the water volume is constant, the water saturation decreases and relative permeability to gases increases.

This paper presents a model that can be used as a prediction or a history matching tool for CBM performance. It can be used to match the production data to estimate the formation properties, which can then be used to predict future reservoir performance.

2. Model description

The objective of the model was to history match and predict the performance of the CBM formations. First, a forward model was developed for the rate-time performance prediction of the well. In case the formation parameters were not available, the model was inverted in order to use the rate time production history to obtain the reservoir properties that will be used to predict the future performance (Fig. 1).

The developed model assumes that each well is treated individually and the estimated parameters, gas content and pore volume, will give the values for the drainage area of the well. Well interferences were neglected in this work.

2.1. The generalized material balance equation (GMBE)

The aim of the GMBE is to predict the CBM performance with pressure depletion by predicting the water saturation in the reservoir, the incremental water and gas production with a drop in pressure.

A GMBE is developed in order to account for the porosity variation due to matrix shrinkage and formation compressibility, and the solubility of methane in water. The tank model concept was used to develop the GMBE (Fig. 2). It is based on a volumetric balance where the pore volume at any pressure or time is equal to the summation of free water and gas volumes. This means that the change in the pore volume is equal to the summation of changes in the free water volume and free gas volume with pressure depletion.

$$\Delta\mathbf{V_p} = \Delta\mathbf{W_f} + \Delta\mathbf{G_f} \tag{3}$$

The reservoir pore volume changes due to formation compaction and matrix shrinkage. According to Clarkson et al. (2010), Liu and Harpalani (2013), Palmer (2009), and Shi and Durucan (2005), the change in porosity, $\Delta\varnothing$, can be calculated as follows:

$$\Delta\varnothing = \varnothing_\mathbf{i}(\mathbf{c_f}\Delta\overline{\mathbf{P}}-\mathbf{c_s}\Delta\mathbf{P}^*) \tag{4}$$

Where,

$$\Delta\mathbf{P}^* = \left[\frac{\mathbf{P_i}}{\mathbf{P_i}+\mathbf{P_L}}-\frac{\mathbf{P}}{\mathbf{P}+\mathbf{P_L}}\right], \quad \text{and} \quad \Delta\overline{\mathbf{P}} = \mathbf{P_i}-\mathbf{P} \tag{5}$$

$\mathbf{c_f}$ is the formation compressibility. c_s is the matrix shrinkage coefficient, which is a function of the formation mechanical properties and the gas properties. The history matching technique can be used to determine c_s.

The absolute permeability can be predicted as a function of porosity (Zhou et al., 2013) as follows:

$$\frac{\mathbf{k}}{\mathbf{k_i}} = \left(\frac{\varnothing}{\varnothing_\mathbf{i}}\right)^3 \tag{6}$$

By assuming a constant bulk volume, the change in the pore volume can be calculated as follows:

$$\Delta\mathbf{V_p} = \mathbf{V_{pi}}(\mathbf{c_f}\Delta\overline{\mathbf{P}}-\mathbf{c_s}\Delta\mathbf{P}^*) \tag{7}$$

The water volume in the reservoir changed due to water expansion and production.

$$\Delta\mathbf{W_f} = \mathbf{W_iB_{wi}}-(\mathbf{W_i}-\mathbf{W_p})\mathbf{B_w} \tag{8}$$

The change in the free gas volume is described by Eqs. (9)–(12). It is equal to the difference between the initial free gas in the reservoir and the current residual free gas.

$$\Delta\mathbf{G_f} = \mathbf{G_{fi}}-\mathbf{G_{fr}} \tag{9}$$