ARTICLE IN PRESS

Journal of Petroleum Science and Engineering xx (xxxx) xxxx–xxxx

Contents lists available at ScienceDirect

Journal of Petroleum Science and Engineering

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

A semianalytical approach to estimate fracture closure and formation damage of vertically fractured wells in tight gas reservoir

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ARTICLE INFO

Keywords:
Tight gas
Fracture closure
Formation damage
Multi-segment fracture
Flux density
Fracture conductivity

ABSTRACT

This paper presents a new semianalytical method to estimate the fracture closure and formation damage by formation evaluation in tight gas reservoirs. A new well interpretation model is established by assuming that the fracture half-length can be divided into N segments with different fracture conductivity and flux density. New semi-analytical solutions and type curves are developed based on this model, while sensitivity analysis is also conducted. The pressure and pressure derivative behavior show that the multi-segment fracture model exists new flow regimes which are termed first interference formation linear flow and second interference formation linear flow and can be characterized by straight line with slope m1 and m2 on the pseudo bottom-hole pressure derivative curve. The case study in field tests highlights the accuracy of this new model in the interpretation of formation and fracture characteristics compared with conventional uniform-flux fracture model, especially the effective fracture half-length. The extent of fracture closure and formation damage evaluated by this new method can be further applied to enhance tight gas recovery.

1. Introduction

Hydraulic-fracturing is an important well-stimulation technique that has widespread applications in oil and gas fields to improve oil and gas productivity in low-permeability and unconventional reservoirs, or to augment production in secondary-recovery operations. For many decades, conventional pressure-transient tests have been conducted on fractured wells to estimate well productivity and to determine formation and fracture characteristics, especially the effective fracture half-length.

Since 1950s, several attempts have been done to investigate the effect of fracture on pressure-transient behavior of vertical wells. Prats et al. (1962) were the first to discuss the performance of vertically fractured reservoirs and to concern the production behavior of vertically fractured wells under constant bottom-hole pressure. Then, an electrical analog method (Dyes et al., 1958; McGuire and Sikora, 1960) and a heat flow model (Scott, 1963) were used to investigate transient pressure behavior of fractured wells at a constant flow rate. Russell and Truitt (1964) developed transient drawdown solutions for vertically-fractured liquid wells. These solutions were applied to water injection wells by Clark (1968) to calculate fracture length from drawdown tests. Millheim (1968) further extended Russell's solutions to low-permeability gas wells and developed diffusion equations for ideal gas flow. Wattenbarger and Ramey (1969) presented well interpretation model for fractured gas wells by considering real gas flow. Lee and Holditch (1981) discussed four basic methods to determine formation and fracture parameters in low-permeability gas reservoirs, including Horner curves, linear flow analysis, type curves, and reservoir simulator history matching. Furthermore, Holditch et al. (1983) proposed a technique for build-up test analysis by combining Horner curves method and linear flow analysis method.

Over the past several decades, different mathematic models have been described to explore the pressure response of fractured wells. In these models, the real fractures were assumed to be planes intersecting the wellbore with uniform flux density (the flux density here is defined as flow rate per length) along the fracture. All these models were developed to solve the unsteady-state flow problem of fractured wells by using source solution and Green's function which were presented by Gringarten and Ramey (1973). Gringarten and Ramey (1974a, 1974b and 1975) developed three basic solutions and type-curve analysis, including the infinite-conductivity solution, the uniform-flux solution for vertical fractures, and the uniform-flux solution for horizontal fractures. Cinco et al. (1975) presented the solutions for uniform-flux and infinite-conductivity inclined fracture. Dinh and Tiab (2010) discussed the effect of fracture angle on pressure behavior of vertical well with an inclined fracture. To solve the problem for finite-

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http://dx.doi.org/10.1016/j.petrol.2016.10.049
Received 16 July 2016; Received in revised form 10 October 2016; Accepted 28 October 2016
Available online xxxx
0920-4105/

Please cite this article as: Huang, Y., Journal of Petroleum Science and Engineering (2016), http://dx.doi.org/10.1016/j.petrol.2016.10.049

Nomenclature

B	formation volume factor
C_t	compressibility
C	wellbore storage coefficient
C_D	dimensionless wellbore storage coefficient based on fracture half-length
h	formation thickness
k	formation permeability
C_{fi}	fracture conductivity of segment i
C_{fiD}	dimensionless fracture conductivity of segment i based on fracture half-length
p	reservoir pressure
p_O	reference pressure, p_O=0 MPa
p_i	initial reservoir pressure
P_{SC}	pressure at standard condition
Psc	0.10325 MPa
q	total well flow rate
q_i	well flow rate of segment i
q_{iD}	dimensionless well flow rate of fracture-segment i based on fracture half-length
s_f	pseudo skin factor
t	time
t_D	dimensionless time based on the fracture half-length
T	formation temperature
T_{SC}	temperature at standard condition, Tsc =293 K
u	Laplace space variable
w_f	fracture width
$x,y,$	space coordinates
$x_D,y_D,$	dimensionless coordinates based on the fracture half-length
x_f	fracture half-length
x_{fi}	fracture half-length of segment i
x_{fiD}	dimensionless fracture half-length of segment i based on fracture half-length
ψ	pseudo reservoir pressure
ψ_i	initial pseudo reservoir pressure
ψ_{wD}	pseudo bottom-hole pressure
η	hydraulic diffusivity
φ	porosity
μ	gas viscosity

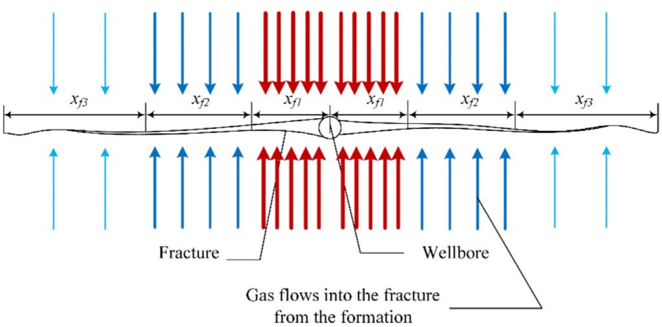

Fig. 1. Multi-segment fracture with non-uniform flux density and fracture conductivity.

conductivity vertical fracture in infinite slab reservoirs Cinco et al. (1978) developed a new mathematic model, and Cinco (1981) further applied this finite-conductivity fracture model in field tests by using pressure type curves. Since pressure type curves were not adequate for well test interpretation, pressure derivative type curves (Bourdet et al., 1983; Wong et al., 1986; Tiab and Puthigai, 1988) were developed to interpret formation and fracture characteristics. Compared with pressure type curves, the pressure derivative curves are more sensitive to the change of characteristics of formation and well so that different flow regimes can be detected more clearly from the pressure derivative curves.

However, the conventional models mentioned above are over-simplifications since they all assumed that the flux density and fracture conductivity along the fracture are uniform. They have limitations in interpreting well-test data from fractured gas wells because the effects of fracture closure and formation damage, usually caused by fracture fluid residue and proppant breakage, on pressure behavior of fractured gas wells are ignored. Since the fracture closure and formation damage may result in non-uniform flux density and fracture conductivity along the fracture (Fig. 1), the application of conventional models are not able to estimate the possible fracture closure and formation damage from well-test data, and may lead to inaccurate results in the evaluation of fracture and formation parameters, especially the effective fracture half-length. Lee and Holditch (1981) have demonstrated that the fracture half-length determined from the reservoir simulation history matching and pseudo-radial flow type curve matching are both less than the designed lengths. This also motivated us to establish a new model to estimate the effect of fracture closure and formation damage on the pressure behavior of fractured gas wells from pressure-transient test.

Nowadays, experimental method have been applied to estimate the dilation mechanisms of hydraulic fractures (Lin et al., 2015) and well-logs data also have been applied in the Coal Bed Methane Exploration (Chatterjee and Paul 2013; Ghosh et al., 2014). He et al. (2016a and 2016b) provided a semi-analytical solution to diagnose the locations of underperforming hydraulic fractures of multi-fractured horizontal wells based on well test data in tight gas reservoir. However, very few studies were conducted to investigate the pressure behavior of hydraulic fractures with non-uniform flux density and fracture conductivity. To solve this problem, Huang et al. (2016) developed a double-segment fracture model for vertically fractured wells and applied this model to oil field tests. Huang's model only divided the fracture half-length into two segments with different flux density and fracture conductivity. However, in our assumptions, the fracture should be divided into more segments with different flux density and fracture conductivity since this assumption can be more practical for actual field tests. The purpose of this work is to extend the double-segment fracture model to multi-segment fracture model, and develop a new semianalytical method, on the basis of pseudo bottom-hole pressure (PBHP) derivative concept, for interpreting pressure-transient tests in vertically fractured gas wells to estimate the extent of fracture closure and formation damage. Field test data are further interpreted by this method for formation evaluation, which demonstrates the accuracy of this model and explores the feasible application of this method in formation evaluation of vertically fractured wells in tight gas reservoirs.

2. Pressure response modeling methodology

New assumptions were presented to derive a new mathematical model. Then, the new semianalytical solution was developed based on this model.

2.1. Assumptions

Consider a fractured gas well model with a vertical fracture, as shown in Fig. 2. Other assumptions are as follows:

- The reservoir is an infinite, isotropic, homogeneous reservoir that contains slightly compressible gas of constant compressibility C_t, and viscosity μ.