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Discrete fracture networks modeling of shale gas production and revisit rate transient analysis in heterogeneous fractured reservoirs

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ABSTRACT

Horizontal wells with multiple hydraulic fractures are necessary stimulation technique for economically developing tight and shale gas reservoirs. In such reservoirs, the conventional well-test techniques are not suitable because of ultralow formation permeability. Rate transient analysis (RTA) is the widely used tool for analyzing these reservoirs for the purpose of reserves estimation, hydraulic fracture stimulation optimization, and development planning. However, the conventional rate transient analysis is based on the models that were derived from idealistic assumptions for homogenous reservoirs. In this article, we first review the industry's common practice for rate transient analysis and discuss why the idealized conceptual model may not be adequate for analyzing production data from shale gas reservoirs. Then, a unified shale gas reservoir model based on Discrete Fracture Networks (DFN) is presented to investigate how each mechanism influences shale gas production and the corresponding rate transient behavior. It is found that shale gas production and rate transient behavior are significantly impacted by reservoir heterogeneity, fracture networks, non-Darcy flow, gas adsorption and completion efficiency. Short early-time linear flow with long transitional flow period is an indication of either existence of abundant complex fracture networks or heterogeneous completion with unevenly distributed hydraulic fractures. Consider the nature of non-unique results of RTA, information from other independent sources is required to achieve a consistent and holistic interpretation.

1. Introduction

The matrix permeability of shales is generally in the range of nano-Darcy, so an enormous conductive surface area is required between the wellbore and the shale matrix to attain commercial production rates. To achieve this surface area, massive multi-stage hydraulic fracture treatments are used to create fractures connected to the well. The geometry, areal extent, conductivity, and typology of these propped/un-propped fracture networks, which dictate shale gas production rate and its decline trend (Wang, 2017), are generally difficult to quantify. So it is a challenge to diagnose production behavior and evaluate completion efficiency in these reservoirs. In conventional reservoirs, pressure transient analysis (PTA) is commonly used to estimate reservoir properties and post-stimulation productivity, but it has limited application in tight and shale reservoirs because the shut-in period required to is often too long to be viable. Rate transient analysis (RTA) affords the long-term testing of wells without shutting them in and allows for the estimation of key reservoir properties, which are essential to obtain reliable production forecasts, to estimate reserves and to improve field development strategies.

For production forecast, the decline curve analysis (DCA) is probably the most frequently used production forecasting tool for shale gas reservoirs due to its relative simplicity and speed. The common methods used to estimate oil and gas reserves rely on a set of empirical production decline curves based on the following hyperbolic function (Arps, 1945):

$$q_t = q_i(1 + bD_i t)^{\frac{-1}{b}} \tag{1}$$

where q_t is the production rate at time t, q_i is the initial production rate at time t = 0, D_i and b are two constants (the former is the initial rate of decline in production and b is the rate of change in D_i over time, which control the curvature of the decline trend). The Arps equation was designed for conventional reservoirs where the boundary-dominated flow is the norm. However, shale gas reservoirs are characterized by transient production behavior and in general, boundary-dominated flow only occurs in later times. The flaws in Arps model has led to the development of many new DCA models for predicting estimated EUR in the shale gas wells, such as the power law exponential model (Ilk et al., 2008), logistic growth analysis (Clark et al., 2011) and Duong's model (Duong, 2011), etc. Even though all these models were formulated

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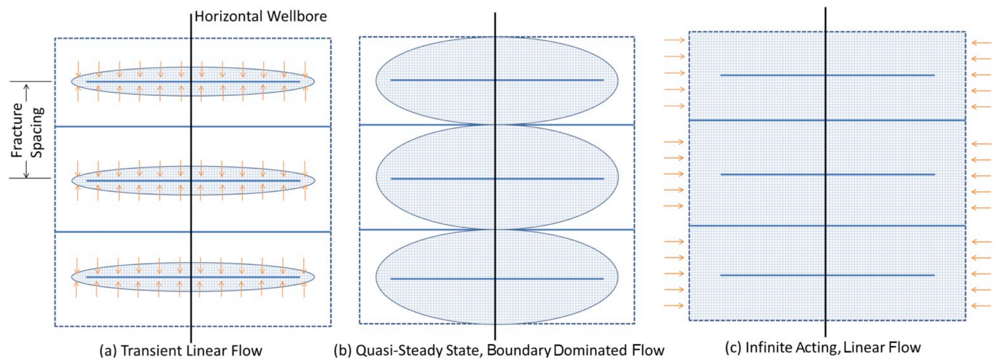

Fig. 1. Top view of typical macroscopic flow regimes for hydraulic fractured horizontal wells during production.

differently, they are all empirical equations and lack of underlying support of physics, so the same production data may lead to different estimation of production decline trend, with different practice of tuning parameters. In addition, empirical models cannot be used to analyze what factors cause the shift of production decline curve in field cases with different practices, which makes it impossible to assign value to one design over another and equally impossible to optimize the treatment for whichever goal is sought, either acceleration of recovery or increase in reserves.

Similar to pressure transient analysis, rate transient analysis starts with the conceptual modeling of wellbore and fracture geometry, then identify the flow regimes by plotting production data on a diagnostic plot. Fig. 1 shows a typical evolution of macroscopic flow regimes during production from a horizontal wellbore with multiple transverse hydraulic fractures in a homogeneous reservoir. For low permeability gas formations, fracture flow capacity is normally large enough to be treated as infinite conductivity and hence bi-linear flow is normally absent, and transient linear flow is often the first flow regime we encounter. Depending on fracture spacing and matrix permeability, this period can last for months or even years. When the pressure disturbance generated by multiple hydraulic fractures start to interfere with each other, virtue no-flux boundaries start to emerge between fractures and isolate each fracture to only deplete fluid in its own compartmentalized domain. This period is often referred as quasi-steady state flow or boundary dominated flow (The mode of boundary dominated flow seen in conventional reservoirs results from the pressure transient investigating all of the surrounding no-flow boundaries in the system, this is unlikely to occur in shale gas reservoirs because the matrix permeability is too low to enable investigation of large areas. In this article, the term “boundary dominated flow” specifically refers to the interference between the adjacent hydraulic fractures when the production pulse reaches the no-flow boundary). In very late time when most recoverable hydrocarbons have been depleted inside each compartmentalized domain, fluid from the far field that beyond the penetration of hydraulic fracture starts to contribute to production, and infinite acting, linear flow ensues. If production time is long enough and without the interference of nearby wells, the pseudo-radial flow may finally emerge. For each flow regime, special plots that based on the assumption of the underlying dominating mechanism can be used to estimate reservoir parameters, such as the drainage area, effective fracture surface area, average permeability, etc. Once these key parameters are required, we can predict the production decline trend and assess the effectiveness of the completion and stimulation design. Because the infinite acting, linear flow and pseudo-radial flow regimes may only occur at the very end of production life, so early-time transient linear flow and boundary dominated flow provide the most valuable data to analyze.

To differentiate macroscopic flow regimes, rate normalized pressure (RNP) can be used (Economides et al., 2012). For gas reservoirs, pressure and rate transient responses need to be analyzed in terms of pseudopressure, $m(P)$, which is defined as (Al-Hussainy and Ramey, 1966):

$$m(P) = 2\int_{P_{ref}}^{P} \frac{P}{\mu_g Z} dP \tag{2}$$

where P_{ref} is some arbitrary reference pressure, μ_g is gas viscosity and Z is gas deviation factor. The rate normalized pressure and its derivative are computed as:

$$\mathrm{RNP} = \frac{m(P_i) - m(P_{wf})}{q(t)} \tag{3}$$

$$\mathrm{RNP}' = \frac{\mathrm{d\,RNP}}{\mathrm{d}\ln(t_e)} \tag{4}$$

where P_i is the initial reservoir pressure, P_{wf} is the wellbore flowing pressure, $q(t)$ is the production rate and t_e is the material balance time, which is calculated with the cumulative production $Q(t)$ as:

$$t_e = \frac{Q(t)}{q(t)} \tag{5}$$

Plot RNP and RNP′ data on a log-log plot against material balance time, we can identify the flow regimes based on the slope of RNP′ (e.g., a half-slope indicates linear flow, a unit slope designates boundary dominated flow and a zero slope reveals radial flow). Once the flow regimes are identified, one can use specialized plots to estimate key reservoir parameters. For instance, the square root of time plot, RNP versus $\sqrt{t}$, is probably the single most important plot to analyze data from the early-time transient linear flow. Based on the early-time transient linear flow solution with the assumption of constant wellbore pressure, the RNP and $\sqrt{t}$ follows a linear relationship (Wattenbarer et al., 1998; El-Banbi and Wattenbarger, 1998):

$$\mathrm{RNP} = \frac{1}{A_f\sqrt{k}} \frac{40.925\,T}{\sqrt{\phi_m \mu_g c_t}} \sqrt{t} \tag{6}$$

where A_f is the total fracture surface area and k is the formation permeability. The slope of the linear portion of RNP versus $\sqrt{t}$ data can be used to estimate $A_f\sqrt{k}$. If boundary dominated flow can be clearly observed right after early-time transient linear flow, then the termination time of transient linear flow can be used to estimate the distance of investigation (DOI), therefore, the fracture spacing, and hydrocarbon pore volumes (HCPV) can be determined based on simple volumetric calculations (Anderson et al., 2010).

Conventionally, RTA is based on the common assumptions that the reservoir is homogeneous and hydraulic fractures are uniformly placed along the horizontal wellbore. This may not be the case if the fracture spacing design is not optimized, the stress interference may prohibit some fractures from growing (Shin and Sharma, 2014) and promote some fractures to coalescence (Wang, 2016). Field study (Minner et al., 2003) also indicates that 80% fracture volume created at the heel and toe of a horizontal well and only 20% fracture volume created at the