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Estimating reliable gas rate with transient-temperature modeling for interpreting early-time cleanup data during transient testing

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ABSTRACT

In drillstem testing (DST), analyses of transient data are generally restricted to the post-cleanup period because rates often go unmonitored at early times during the cleanup phase, unless aided by multiphase flow metering. The value of early-time production data monitoring may be overlooked for two reasons: first, transients may be difficult to interpret because of two-phase flow in the formation; second, two-phase flow metering becomes a requirement.

The objective of this study is two-fold: to estimate rate from multipoint-temperature sensor (MTS) data available for downhole telemetry with a rigorous transient analytical model, and to show the possible use of the computed rates to perform transient analysis for both the pre- and post-cleanup periods. Comparing and contrasting permeability estimates from the two periods provides guidance on the suitability of this approach. To that end, this study compares and contrasts rate computation with analytical methods. The new methods entail transient-temperature modeling with and without superposition effects. Two field examples strengthened the new rate-computation methods introduced here, and simulated examples probed the possibility of extracting meaningful information from the cleanup data.

1. Introduction

Many authors have studied near-wellbore formation damage from various angles over the years because near-wellbore properties are altered by the drilling operation itself, and by the invasion of mud and its filtrate because of over-balanced drilling. From the standpoint of transient-pressure testing, Larsen and Kviljo (1990a) and Larsen et al. (1990b) investigated the analysis of cleanup data. In these studies, the authors explored the variable-skin concept *en route* to establishing the attainment of cleanup. They showed with field data that the derived skin declines in a hyperbolic fashion in conventional tests. Stated differently, production of the invaded mud filtrate declines hyperbolically. This finding showed the diminishing influence of the unwanted phase with time.

Systematic studies, wherein similar tests are run, have evolved in understanding the variable skin in wireline-formation testing, but at a much reduced scale of producing rate and time. The studies of Goode and Thambynayagam (1996), Alpak et al. (2008), Ramaswami et al. (2012), among others, are cases in point. As expected, declining skin turned out to be the norm. Clarkson et al. (2013) observed evolution of skin in coal-bed methane wells. The authors coined the term dynamic-skin ratio, which was included in the dimensionless type-curve variables and flowing-material-balance formulation, to include the effect of changing skin. More recently, Theuveny et al. (2013) explored various nuances of near-wellbore and wellbore cleanup operation with a transient multiphase wellbore simulator coupled with a reservoir-flow simulator.

Distributed-temperature data (DTS) have shown good potential with various forms of testing and analysis. Wang et al. (2008) presented an inverse model based on steady-state energy balance using DTS technology. Duru and Horne (2010) made use of DTS data for estimating formation parameters, such as permeability and porosity, among others, during transient testing. Muradov and Davies (2011), Li et al. (2011), and Tardy et al. (2012), among others, demonstrated the use of distributed measurements in zonal contribution assessment in horizontal wells. The coupled nature of fluid and heat flows in transient testing of gas wells has been the subject of many studies. Some of the examples include those of Kabir et al. (1996), Fan et al. (2000), Hasan et al. (2005), Izgec et al. (2007), and Bahonar et al. (2011a, b). Hasan and Kabir (2012) summarized some of the findings of these studies in a review article. Besides gas wells, Bahonar et al. (2010, 2011) also probed applications of the combined wellbore/reservoir model in

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Nomenclature

c_p	specific heat capacity of fluid, Btu/lbm-F, L^2/t^2T
C_J	J–T coefficient, (°F)/(lb_f/ft^2), TLt^2/m
g	gravitational acceleration, ft/s^2, L/t^2
g_G	geothermal gradient, °F/ft, T/L
k_a	thermal conductivity of the annular fluid, Btu/h-ft-°F, mL/t^3T
k_c	thermal conductivity of cement, Btu/h-ft-°F, mL/t^3T
k_e	thermal conductivity of formation, Btu/h-ft-°F, mL/t^3T
L	total wellbore measured depth, ft, L
L	measured (from wellhead) depth of section 'j' of wellbore, ft, L
L_R	relaxation parameter defined by Eq. (2), ft^{-1}, 1/L
p	pressure, psi, m/Lt^2
q_g	volumetric gas production rate, Scf/D, L^3/t
Q	heat transfer rate per unit length of wellbore, Btu/h-ft, ML/t^3
r_t	tubing radius, ft, L
r_{inv}	radius of mud-filtrate invasion, ft, L
r_w	wellbore radius, ft, L
t	production period, h, t
t_D	$\alpha t/r_{wb}^2$, dimensionless time
t_{sp}	soak period, h, t
T_D	dimensionless temperature defined by Eq. (A-2).
T or T_f	fluid temperature, °F, T
T_c	calculated fluid temperature, °F, T
T_e	earth or formation temperature, °F, T
T_e	undisturbed earth or formation temperature, °F, T
T_{eij}	undisturbed earth or formation temperature at L_j, °F, T
U	overall-heat-transfer coefficient, Btu/h-ft²-°F, m/t^3T
v	fluid velocity, ft/h, L/t
w	mass rate, lbm/h, m/t
z	variable wellbore measured depth from surface, ft, L
Z	gas compressibilty factor, dimensionless
α	thermal diffusivity of the formation, ft^2/h, L^2/t
θ	well inclination (to horizontal) angle, degree
ρ	fluid density, lbm/ft^3, m/L^3
ϕ	lumped parameter defined by Eq. (A-13), F/ft, T/L
Ψ	lumped parameter, Eq. (A-17), °F/ft, T/L

Subscripts

f	fluid
j	spatial coordinate

the context of steam injection. Both forward and inverse modeling is possible with these coupled tools.

In conventional testing, Kabir et al. (2014) recently showed applications of the MTS data, which is a particular case of DTS, in rate estimation for the stable flow periods. That study neglected both the transient-temperature signature and its superposition effects for simplicity. Indeed, to the best of our knowledge, all models for rate estimation from fluid temperature neglect temperature transients and their superposition effects. This aspect may severely limit the utility of prior models because much of the temperature data from cleanup periods are from situations that do not allow enough time to attain steady thermal equilibrium. This paper explores the feasibility of improving rate computation with rigorous superposition formulations of transient-temperature data gathered during drillstem testing. We were motivated to pursue this option because in many field operations the cleanup period in a newly completed well goes unmonitored unless aided my multiphase flow metering. Intrinsically, if the cleanup period yields reasonable formation conductivity (kh) and skin values, considerable time saving can result because the designed test sequence can be altered with respect to flow rates and flow periods, commensurate with test objectives.

2. Model development

This study interprets cleanup data in a gas well using rates derived from distributed-temperature measurements. This strategy requires robust fluid temperature models that estimate rates during drawdown periods. During production, fluid temperature at various depths in the wellbore can be estimated using the fluid rate. When the distributed temperatures are available, the opportunity arises to solve the inverse problem for estimating rates. As discussed earlier, the technique for estimating rate with steady-state models is available for the stable flow condition. In other words, that methodology is applicable only when the fluid and heat flow attain stability, a process that usually takes hours after a rate change occurs. In this study, we show the innovative use of temperature transients for estimating rates under variable-flow conditions. In addition, we investigate the improvement caused by incorporating depth-dependent temperature superposition in both the steady state and the transient models. In the following sections, we offer the operating equations. Appendix A details the model derivation and definition of various terms.

All flowing fluid-temperature models assume that heat exchange between the formation and the fluids remain constant throughout the entire production period. In general, however, as production continues, fluid temperature tends to approach the surrounding formation temperature, thereby decreasing heat transfer rate with time. To account for this changing heat flow, the superposition principle is used. We emphasize that this model handles superposition of heat flow for a given rate. Therefore, for the models given below, we employ superposition of heat flow to account for temperature transients for a given gas rate. For subsequent changes in gas rate, the final temperature of the previous rate constitutes the boundary condition.

2.1. Transient-temperature model

When production is initiated or when the production rate is changed, thermal transients set in that take a much longer time to stabilize than its pressure counterpart. The flow rate becomes stable soon after its initiation or change from one rate to another. However, temperature changes for the corresponding period take a much longer time to attain stability. Assuming that mass and momentum transients of wellbore fluids die rapidly, Appendix B shows the derivation of an expression for the transient-fluid temperature. We account for the effect of variable heat flux at any discrete time by adding ξ that represents the superposition term, as shown in Appendix A. Using the ξ term, we derived the following expression for transient flowing fluid temperature:

$$T_f = T_{ei} + \frac{\left(1 - e^{-at}\right)\left(1 - e^{(z-L)L_R}\right)}{L_R}(\psi + \xi) + (T_{fi} - T_{ei})e^{-at} \quad (1)$$

where