International Journal of Heat and Mass Transfer 127 (2018) 375–395

Contents lists available at ScienceDirect

International Journal of Heat and Mass Transfer

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

Investigation of temperature behavior for multi-fractured horizontal well in low-permeability gas reservoir

Hongwen Luo [a,*], Haitao Li [a,*], Yahui Li [a], Yu Lu [a,b], Yongsheng Tan [a]

[a] State Key Laboratory of Oil and Gas Reservoir Geology and Exploitation, Southwest Petroleum University, Chengdu 610500, China
[b] Department of Chemical and Petroleum Engineering, Schulich School of Engineering, University of Calgary, Calgary T2N 1N4, Canada

ARTICLE INFO

Article history:
Received 16 January 2018
Received in revised form 28 June 2018
Accepted 8 July 2018

ABSTRACT

This study aims to interpret the temperature behavior of a cemented multi-fractured horizontal well (MFHW) in a low-permeability gas reservoir (LPGR) during production. First, considering heat conduction, heat convection, thermal expansion, viscous dissipation, and the Joule–Thomson effect, a comprehensive numerical temperature prediction model is developed under a single-phase condition. The developed models are formulated for the reservoir and wellbore domains based on mass, momentum, and energy conservation. The non-Darcy law is applied to the numerical models, and radial flow in the hydraulic fractures is accounted for when the reservoir and wellbore models are coupled. These developed models are solved numerically by the finite difference method. Then, synthetic cases demonstrate the models' ability to predict the temperature behavior and clarify the change regularity of the wellbore temperature profile for an MFHW in an LPGR. The effects of pressure interference among hydraulic fractures on the inflow rate are analyzed. Based on the sensitivity of arriving temperature to the fracture parameters, an approach to plotting fracture parameter diagnosis charts are introduced. In addition, a field case is provided to illustrate the application and feasibility of the new models on the basis of the accurate simulated results of wellbore temperature profiles.

1. Introduction

With the development of temperature testing technology, downhole temperature measurement has become a widely used technique to qualitatively or quantitatively interpret reservoir conditions underground. Downhole temperature data are usually measured by production logging tools (PLTs), permanent downhole gauges, and fiber-optic cables. In particular, because fiber-optic cables can monitor the real-time temperature behavior along entire well sections, they are treated as distributed temperature sensors (DTSs) [1,2].

By establishing theoretical models, temperature measurement data can be used for quantitative interpretation of reservoir properties, determination of water/gas entry, evaluation of completion effectiveness, interpretation of the inflow profile, etc. [3–5]. Ramey [6] proposed the earliest wellbore temperature model for a vertical well, and his model has been extended by other scholars to obtain reservoir properties near the wellbore [7,8]. Sui and Zhu [9] developed a new model to determine the conditions for multilayer formation. Unlike the case for vertical wells, in horizontal wells, the temperature differences along entire horizontal well sections due to the Joule–Thomson effect are very small (usually less than 1–2 °C) [10,11]. To identify these tiny temperature changes, micro-heating effects, such as the effects of fluid expansion, viscous dissipation, heat conduction, and thermal convection, should be considered when the temperature models are developed [12–14]. Maubeuge et al. [15] proposed an early thermal model for an oil reservoir considering thermal expansion and viscous dissipation. Yoshioka et al. [3] developed a temperature model to solve the wellbore temperature and pressure distribution for a horizontal well in an oil reservoir, although the wellbore and reservoir were not coupled. Using the temperature model, they determined the inflow profile [16] and quantitatively detected water or gas entry into horizontal wells using downhole temperature measurement data [10]. A transient reservoir temperature model and a wellbore model under the steady state were coupled to predict the flow profile from the measured temperature and pressure data [17], and the models were applied to a field case [18]. Zhu and Achinivu [19] proposed a method to interpret downhole temperature and pressure data for horizontal or highly inclined wells and detected water entry for a inclined well in a gas reservoir [5]. A comprehensive oil–water two-phase model was established to predict the temperature distribution for a horizontal well by Zhu et al. [20], and this model was applied to interpret the inflow profiles using distributed temperature measurement [21]. The above studies

* Corresponding authors.
E-mail address: rojielhw@163.com (H. Luo).

https://doi.org/10.1016/j.ijheatmasstransfer.2018.07.043
0017-9310/

Nomenclature

A	surface area of the wellbore segment, m^2
C_g	gas compressibility, MPa^{-1}
C_p	heat capacity of fluid, J/(kg·K)
C_{ps}	heat capacity of solid reservoir rock, J/(kg·K)
d_F	fracture spacing, m
f	friction coefficient
f_{cd}	fracture conductivity, mD·cm
g	gravitational acceleration, m/s^2
h	internal energy, J
h_F	fracture height, m
h_{Tt}	overall heat transfer coefficient, W/(m^2·K)
h_z	reservoir thickness, m
k	permeability, mD
k_c	thermal conductivity of the casing, W/(m·K)
k_{cem}	thermal conductivity of the cement, W/(m·K)
k_F	fracture permeability, mD
K_{JT}	Joule–Thomson coefficient, °C/MPa
k_T	reservoir heat conductivity, W/(m·K)
k_t	thermal conductivity of the tubing, W/(m·K)
k_x	reservoir permeability in x direction, mD
k_y	reservoir permeability in y direction, mD
k_z	reservoir permeability in z direction, mD
L_x	reservoir width, m
L_y	reservoir length, m
L_z	reservoir height, m
M	molecular weight of natural gas, nondimensional
n_F	number of fractures
p	flow pressure in formation, MPa
p_o	reference pressure, MPa
P_{wf}	bottom-hole pressure, MPa
q_F	flow rate in fracture, m^3/d
q_{wb}	conduction heat transfer rate per unit volume, W/m^3
$\overline{q_{wb}}$	thermal conduction transfer rate, W
r	radius, m
R	gas constant, Pa·m^3/(mol·K)
r_{eff}	effective radius, m
R_{inw}	inner radius of the wellbore, m
r_w	radius of wellbore, m
t	production time, days
T	reservoir temperature, °C
T_F	fluid temperature in the fracture, °C
T_i	initial reservoir temperature, °C
T_I	inflow temperature, °C
T_r	pseudo-reduced temperature, nondimensional
T_{wb}	wellbore temperature, °C
v	velocity of fluid, m/s
v_I	velocity of inflow fluid, m/s
W_F	fracture width, m
x_e	half of reservoir width, m
x_F	fracture half-length, m
y_e	half of reservoir length, m
Z	deviation factor of gas, nondimensional
z_e	half of reservoir height, m

Greek letters

ψ	pseudo-pressure, MPa^2/mP·s
μ	fluid viscosity, mP·s
β	thermal expansion coefficient, 10^{-4}/°C
ø	porosity of formation, fraction
μ_g	gas viscosity, mP·s
σ	non-Darcy factor, nondimensional
σ_{gx}	non-Darcy factor in x direction, nondimensional
σ_{gy}	non-Darcy factor in y direction, nondimensional
σ_{gz}	non-Darcy factor in z direction, nondimensional
ψ_i	initial pseudo-pressure, MPa^2/mP·s
ψ_i	bottom-hole pseudo-pressure, MPa^2/mP·s
ϕ_F	porosity of fracture, fraction
ρ	density of fluid, kg/m^3
$\overline{\rho C_p}$	average heat capacity, J/(kg·K)
ρ_I	density of inflow fluid, kg/m^3
ρ_r	pseudo-reduced density, nondimensional
γ	pipe-open ratio, fraction
θ	dip of horizontal well sections, °
Δx	mesh size in x direction, m
Δy	mesh size in y direction, m
Δz	mesh size in z direction, m

Subscripts

cem	cement
ci	inner casing
co	outer casing
eff	effective
f	fluid
F	hydraulic fractures
I	inflow
s	solid reservoir rock
ti	inner tubing
to	outer tubing
wb	wellbore

Abbreviations

BHP	bottom-hole pressure
DAS	distributed acoustic sensor
DTS	distributed temperature sensor
LPGR	low-permeability gas reservoir
MFHW	multi-fractured horizontal well
PLT	production logging tool
TVD	true vertical depth

were all conducted on vertical wells or conventional horizontal wells.

Because fracturing stimulation is widely used worldwide to enhance productivity, increasing numbers of researchers are studying the performance of fractured horizontal wells in oil/gas reservoirs using detected temperature information. Molenaar et al. [22] discussed how to use DTS and distributed acoustic sensor (DAS) maps to enhance the monitoring, assessment, and optimization of fracturing treatment. From DAS and DTS images, fracture initiation, fracture propagation, and fracture progression during fracturing treatment of multicluster, multistage horizontal tight gas wells have been demonstrated [23–25]. Ugueto et al. [26] obtained the perforation cluster efficiency and identified the effectively supported fracture using fiber-optic diagnostics (measured data from DAS and DTS). To quantitatively explain downhole temperature data for multi-fractured horizontal wells (MFHWs), the corresponding mathematical models have also been established. On the basis of Yoshioka's model [3], Yoshida et al. [27] proposed a new model to estimate the temperature profile for an MFHW in a shale gas reservoir, and they applied the model to several synthetic cases. Cui et al. [28] developed a transient temperature model for single-phase gas wells, and their model was applied to two field examples. In their field applications, the interpreted temperature profiles based on the estimated inflow rate were matched with the measured temperature data from PLTs [29]. Yoshida et al. [2] proposed a numerical model to simulate the downhole