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Detecting Fluid Influx from Temperature profiles in Porous Media

M. Enamul Hossain[a] *, S. Hossein Mousavizadegan[b], M. Rafiqul Islam[c]

[a] *Post Doctoral Research Fellow, Dept of Civil & Resource Eng, Dalhousie University, Halifax, NS, Canada B3J 2X4*
[b] *Assistant Professor, Faculty of Marine Technology, Amirkabir University of Technology, Tehran, Iran*
[c] *Professor, Dept of Civil & Resource Eng, Dalhousie University, Halifax, NS, Canada B3J 2X4*

Abstract

Detecting fluid influx has numerous applications in the petroleum industry, both in upstream and downstream operations. If pipelines and horizontal wells are equipped with sensors, which are inexpensive, the temperature profile can be generated and mapped during the entire duration of an operation. The primary causes of temperature change for each phase (oil, water, gas) are the differences in Joule-Thomson effects. These effects are caused by the pressure change in a tubular (wellbore of pipeline). This paper illustrates a specific criterion for which water or gas entry locations can be identified from the temperature profile of a horizontal tubular. The criterion is demonstrated as a change in slope of the temperature profile at the water or gas entry location. A mathematical model, capable of non-linear data inversion, uses pressure and temperature distribution to determine the water and gas influx along the length of a pipe for various times. The model is applied to carry out a parametric study and to find out the effects of various flow conditions on the temperature profile. It is concluded that temperature profile can be used to identify water or gas influx or to detect the type of fluid entering into the wellbore.

Keywords: Temperature profile, Joule-Thomson effects, horizontal tubular, heat transfer, porous media, numerical model.

Nomenclature

c	Single phase reservoir fluid compressibility, pa^{-1}
c_p	Specific heat capacity of single phase fluid, $kj/kg-k$
D	Elevation or depth from the ground towards the center of earth for reservoir flow or Vertical distance from the reference point for wellbore flow, m
E	Sum of kinetic energy and internal energy $=\rho_i\left(\frac{1}{2}v_i^2+e_i\right)$, kj
e	Internal energy, kj
G	Geothermal temperature gradient, K/m
g_a	Gravitational acceleration in the negative z-direction, m/s^2
H	Enthalpy of single phase fluid per unit mass , kj/kg
h	Overall heat transfer coefficient which depends on the flow rate, type of fluid and completion, $kj/s-m^2-k$
J	Productivity index for the length Δx that can be estimated from reservoir properties
K	Permeability of the reservoir system, m^2
k	Thermal conductivity, $kj/h-m-k$
f_m	Moody friction factor
p	Pressure of the system, pa
p_R	pressure at the assumed constant-pressure boundary at some fixed distance from the well, pa
q	Conductive heat flux, $kj/s-m^2$
r	Wellbore radius (i.e., pipe radius)
S	Saturation, m^3/m^3
t	Time, s
T	Temperature in the formation, k
T_{ref}	A reference temperature at a distance D from the wellbore towards the earth surface, k
T_r	Reference temperature of reservoir fluid, k
T_s	Average temperature of the solid rock matrix, k
U	Internal energy of single phase fluid per unit mass, kj/kg
$\boldsymbol{u_f}$	Fluid velocity vector, m/s
v	Average fluid influx velocity over wellbore segment, kg/s
v_m	mixture (fluid) velocity $=\frac{\sum_i \rho_i v_i y_i}{\sum_i \rho_i y_i}$
y	In-situ face fraction or holdup, m^3/m^3

Greek Symbols

μ	Fluid dynamic viscosity, $Pa.s$
ρ	Single phase mass density, kg/m^3
ρ_m	mixture (fluid) density $=\sum_i \rho_i\ y_i$
ρ_r	Reference single phase mass density, kg/m^3
ϕ	Porosity of the rock matrix, m^3/m^3

* Corresponding author. Tel.: +19024227544
Fax: +19024943108; E-mail: mehossain@dal.ca

β Thermal expansion coefficient, $1/k$
γ Pipe opening ratio $= \frac{Open\ pipe\ surface\ area}{Pipe\ surface\ area}$
τ Wall shear stress $= \frac{\rho_m f_m v_m^2}{2}$, pa

Subscripts
ei Influxing phase at wellbore
f Reservoir fluid (i.e. $g + o + w$)
g Reservoir gas
i Reservoir fluid phase at wellbore (i.e., $i = o, g, or\ w$)
I Initial condition
o Reservoir oil
s Solid reservoir rock matrix
t Total rock and fluid (i.e. $s + f$)
w Reservoir water
W Well
z Reservoir reference point at the surface
(T, t) Function of temperature and time

Exponents
i Iteration number

Notations
$\sum_f (function)$ Summation sign

1. Introduction

Solid rock matrix properties are functions of the media temperature and pressure. Therefore, it is necessary to know the temperature and pressure distribution to predict these properties. Fluid properties also depend on mixture composition, pressure and temperature (Joule-Thomson effect). Joule-Thomson effect is the change in temperature that accompanies expansion of a fluid without production of work or transfer of heat. At ordinary temperatures and pressures, all real gases except hydrogen and helium cool upon such expansion.

Fluid temperature depends on surroundings temperature, surroundings conductivity (e.g. limestone, sea water, and air), insulation, inside film conductivity and residence time. As a result, recent advancement on measuring pressure and temperature [1, 2] are introduced. The use of distributed temperature sensor (DST) has made the objectives easier, faster and accurate. At present, it is possible to obtain a temperature profile with a resolution of less than 0.1 ºK with the aid of this technological advancement. Thus, it is possible and very important to measure an accurate data to find out temperature profile which can be used to ascertain the water entry or water breakthrough in the wellbore. In this study, the shortcomings of measuring technique of temperature and placement of sensors in a well are ignored. Here, we are focusing only the temperature data and their value for monitoring well performance in producing wells so that water entry or early water breakthrough can be detected from temperature profile.

The use of temperature profile in a horizontal well for detecting water entry has been previously used by several authors [1, 2]. They varied the production rate and types of oil to see their effects on temperature profile. They assumed that flowing fluid and rock temperature are same. They did not check the effects of fluid velocity and injection steam velocity on temperature distribution. Recently, Hossain et al. [3, 4] have investigated the influence of fluid and injection steam velocity. They also showed the variation of temperature profile if rock and fluid temperature are considered different. An extensive review of temperature propagation and its dependence on several parameters are presented in our previous works [3 – 5]. Yoshioka et al. [6, 7] presented models for predicting the temperature profile in a horizontal well. They presented methods [6] to interpret measurements in complex wells for the determination of the inflow profiles of oil, gas and water. This is for a steady state flow condition. They assumed the reservoir is ideally isolated with each segment. They considered a box-shaped homogeneous reservoir. They investigated the effects of production rate, permeability and fluid types on temperature profiles.

The available literature [8, 9] shows an extensive review on fluid properties changes due to heat loss in the reservoir formation and wellbore. It is due to the more tempting changes of fluid properties with temperature change. The present model mathematically formulated using mass and energy balances for two-phase flow both in the reservoir and wellbore. Multiphase correlations are very sensitive to density, viscosity and surface tension. Presence or absence of liquid is more important than relative volume of liquids which guide the temperature distribution along the horizontal wellbore. This model includes the Joule-Thomson effect (temperature change due to pressure drop) which is the main difference from the conventional oil recovery model. As the temperature change of a producing well is anticipated to be small, all of the probable and slight energy changes in the reservoir must be included.

In this study we are focusing on how to find an alternative way to detect water breakthrough or water-coning by assuming that the downhole temperature sensors are permanently installed in the horizontal well. The basis of this study is to develop temperature profiles with time from which we can detect any change or anomaly of temperature profile due to water entry or breakthrough. The similar procedure may be applied for gas entry from a gas-cap.

2. Model Description

It is taken into account a porous media of uniform cross sectional area and homogeneous along *x*-axis. It is normal practice to consider that the fluid flow in porous media is governed by Darcy's law. Since the media is homogeneous, the pressure along *x*-direction may be considered to be varied based on Darcy diffusivity equation. It is also considered that the thermal conductivity of fluid and solid rock matrix is not a function of temperature and constant along the media. In the initial stage of the reservoir, there is a uniform distribution of pressure and temperature throughout the reservoir. The boundary conditions are defined later. Figure 1 shows the schematic diagram of a horizontal well in porous media for mass and momentum change along a wellbore with mass transfer through perforation. The top and sides of the rectangular reservoir are sealed and pressure below the reservoir (aquifer's pressure) is constant. A fully penetrating horizontal wellbore is considered. We assume a steady state reservoir with constant fluxes from both ends and no flow at the outer boundaries.

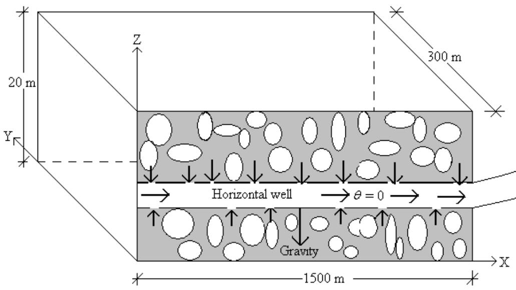

Fig. 1. Schematic diagram of a horizontal well in porous media

A reservoir of length (L = 1500.0 m), width (W = 300 m) and height, (H = 20 m) is considered. Analysis of multiphase flow behavior can be adapted for slightly inclined systems (Figure 2). Therefore, an inclination of $\theta = 5°$ has been accounted in this study. The porosity and permeability of the reservoir are 25% and 10 md, respectively. The reservoir is completely sealed and produces at a constant rate where the initial pressure is $P_i = 27579028\, pa$ (4000 psia).

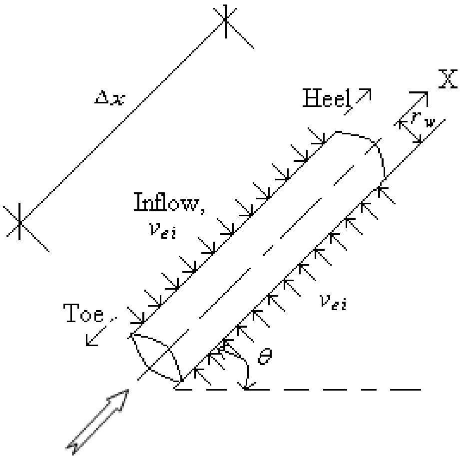

Fig. 2. Schematic diagram of a slightly inclined well in porous media

3. Mathematical model for Horizontal Well

For non-isothermal flow in the reservoir, we can develop mass and energy balance equations for both reservoir and wellbore flow. To get the temperature and pressure profiles within the specified boundary conditions, we need to solve the coupled reservoir and wellbore equations. The resultant solution will provide the temperature profile along the horizontal well.

3.1. Model for Reservoir Flow

The mass and energy balance equations in porous media have been presented widely in petroleum engineering literature. In this study, we consider density, porosity and saturation are function of time. To derive the mathematical model of our problem, the mass and energy balance equations are formulated separately.

3.1.1. Mass Balance Equation

The partial differential form of mass balance [1, 2, 8] in a reservoir formation is can be written as

$$-\nabla.\left(\rho_f \boldsymbol{u_f}\right) = \frac{\partial}{\partial t}\left(\phi \rho_f S_f\right) \quad (1)$$

where $\boldsymbol{u_f}$ is the Darcy velocity vector, $\boldsymbol{f}$ represents the phase of the fluid. The divergence operator (∇) on the left side of the above equations could be expanded in any coordinate system. Expanding the right hand side of Eq. (1), and using the definition of fluid compressibility, we obtain the mass balance equation for the reservoir flow as

$$-\frac{1}{\rho_f}\nabla\cdot\left(\rho_f\, \mathbf{u_f}\right) = \phi\, \frac{\partial S_f}{\partial t} + \phi\, S_f\, c_f\, \frac{\partial p_f}{\partial t} + S_f\, \frac{\partial \phi}{\partial t} \quad (2)$$

3.1.2. Energy Balance Equation

The energy balance equation may be considered as the governing equation for both rock and fluid separately when the temperature of rock and fluid is different. When the temperature of rock and fluid are considered same, the two equations may be combined to present the temperature distribution in porous media. Hossain et al. [3, 4] showed that the temperature distribution in porous media is very close to each other when the temperature of rock and fluid is considered different. Therefore, in this study; we have considered rock and fluid temperature are same. The partial differential equations have a familiar form because the system has been averaged over representative elementary volumes (REV). A right handed Cartesian coordinate system is considered where the x-axis is along the formation length. The general energy balance equation for non-isothermal flow in formation is well described in literature [8]. If we neglect the kinetic energy for an open system and same rock and fluid temperature, the conservation of energy equation in terms of pressure and temperature for both solid rock and fluid can be expressed as [1, 2, 8]:

$$\frac{\partial}{\partial t}\left(\rho U + \phi \rho_f g_a D_z\right) + \nabla\cdot\left\{\sum_f \rho_f \boldsymbol{u_f}\left(H_f + g_a D_z\right)\right\}$$
$$-\nabla\cdot\left(k_t.\nabla T\right) = 0 \quad (3)$$

where,

$$\rho U = \phi \sum_f \rho_f S_f U_f + (1-\phi)\rho_s U_s$$

Now the change in enthalpy of the system in a situation of Joule-Thomson expansion is given by the relation, $\rho H = \rho U + p$. The density of rock and total thermal conductivity are assumed to be constant. The enthalpy term can be replaced with the thermodynamic relationship. Hence, Joule-Thomson expansion, $dU_s \cong dH_s = c_p dT_s$, $U_s \cong H_s = c_{ps} T_s$, and $dH = c_p dT + \left(\frac{1}{\rho} - \frac{\beta T}{\rho}\right) dp$. Finally, substituting the mass balance Eq. (2) and the above relationship to Eq. (3), the final form of the energy balance equation for single phase fluid becomes as:

$$-\left\{\phi \rho c_p + (1-\phi)\rho_s c_{ps}\right\}\frac{\partial T}{\partial t} + T\left\{\phi\beta - (1-\phi)\rho_s c_{ps} c_s\right\}\frac{\partial p}{\partial t}$$
$$+\left(p + \rho_s c_{ps} T\right)\frac{\partial \phi}{\partial t} - \frac{\partial}{\partial t}\left(\phi \rho g_a D_z\right) = \rho c_p \boldsymbol{u}.\nabla T + \boldsymbol{u}.\nabla p$$
$$-\beta T \boldsymbol{u}.\nabla p + \nabla.\left(\boldsymbol{u}\rho g_a D_z\right) - k_t \nabla^2 T \quad (4)$$

On the right hand side of Eq. (4), the first term is the thermal energy transported by convection. The second term is the viscous dissipative heating and the third term is the thermal energy change caused by fluid expansion. The fourth term is the potential energy. The fifth term is thermal energy transported by heat conduction. The left-hand side is the accumulation of energy. The rate of gravity work may be expanded as:

$$\frac{\partial}{\partial t}(\phi\rho g_a D_z) = g_a D_z\left(\phi c\rho\frac{\partial p}{\partial t} + \rho\frac{\partial \phi}{\partial t}\right) \text{ and}$$

$$\nabla.(\boldsymbol{u}\rho g_a D_z) = -g_a D_z\left(\phi c\rho\frac{\partial p}{\partial t} + \rho\frac{\partial \phi}{\partial t}\right) \qquad (5)$$

Substituting Eq. (5) in Eq. (4), the expression takes the form as:

$$-\{\phi\rho c_p + (1-\phi)\rho_s c_{ps}\}\frac{\partial T}{\partial t} + T\{\phi\beta - (1-\phi)\rho_s c_{ps} c_s\}\frac{\partial p}{\partial t}$$
$$+\left(p + \rho_s c_{ps} T\right)\frac{\partial \phi}{\partial t} = \rho c_p \boldsymbol{u}.\nabla T + \boldsymbol{u}.\nabla p - \beta T\boldsymbol{u}.\nabla p - k_t\nabla^2 T \qquad (6)$$

Equation (6) represents the energy balance equation in reservoir flow for a single phase fluid. In terms of multiphase fluid flow, Eq. (6) may be expressed as:

$$-\{\phi\textstyle\sum_f \rho_f\, c_{pf} + (1-\phi)\rho_s c_{ps}\}\frac{\partial T}{\partial t}$$
$$+T\{\phi\textstyle\sum_f \beta_f\, S_f - (1-\phi)\rho_s c_{ps} c_s\}\frac{\partial p_f}{\partial t} + \{\textstyle\sum_f p_f + \rho_s c_{ps} T\}\frac{\partial \phi}{\partial t}$$
$$= \textstyle\sum_f \boldsymbol{u_f}.\rho_f c_{pf}\nabla T + \sum_f \boldsymbol{u_f}.\nabla p_f - T\sum_f \beta_f \boldsymbol{u_f}.\nabla p_f - k_t\nabla^2 T \qquad (7)$$

where, $\rho_f c_{pf} = \rho_o c_{po} S_o + \rho_g c_{pg} S_g + \rho_w c_{pw} S_w$.

Equation (7) may be solved for pressure and temperature simultaneously using Darcy diffusivity equation for pressure distribution. To find out the ϕ variation with respect to time, we need to consider both permeability and porosity variation. Yoshioka et al. [1] and Dawkrajai et al. [2] did not consider these two parameters as a function time. Here we have considered ρ and ϕ are the function of time.

3.1.2.1 Permeability Change

For a fractured porous media, we assume that the Boussinesq approximation [9 – 11] is valid in the range of temperature, pressure so that the density, ρ is constant except in the buoyancy term ($\rho g_a D_z$) where it varies linearly with the temperature T. So, this approximation is invoked to model the permeability variation with respect to heat transfer in the formation and finally using the Darcy's law, the permeability variation with time and temperature takes the form as:

$$K_{t,\ T} = \frac{-\phi\mu\boldsymbol{u}}{\frac{\partial p}{\partial x} + \rho\{1-\beta(T_r - T)\}g_a} \qquad (8)$$

3.1.2.2 Porosity Change

Researchers [12 – 14] have used Kozeny–Carman equation to link permeability to the effective pore radius. Recently, Hossain and coauthors [5, 9] used a general permeability-porosity relationship as a three term power series of porosity. For average sandstone (porosity range 2 – 40%), Pape et al. [5, 9, 13] found coefficients and exponents as:

$$K_{t,\ T} = 31\,\phi + 7463\phi^2 + 191\,(10\phi)^{10} \qquad (9)$$

To investigate the effects of temperature on porosity, a steady state situation is considered where velocity does not change for a particular time interval. So, for a constant time period, Eq. (9) can be differentiated with respect to time and can be written as:

$$\frac{\partial K}{\partial t} = (31 + 14926\,\phi + 191\times 10^{11}\,\phi^9)\frac{\partial \phi}{\partial t} \qquad (10)$$

The use of momentum equation [9] takes the final form of Eq. (8) as:

$$K_{t,\ T} = \frac{-\phi\mu\boldsymbol{u}}{2\rho g_a - \frac{\mu}{K_I}\boldsymbol{u} - \frac{\rho\partial\boldsymbol{u}}{\phi\partial t} - \rho\beta g_a T_r + \rho\beta g_a T} \qquad (11)$$

For a constant temperature, permeability can be differentiated with respect to time, t and Eq. (11) takes the form as:

$$\frac{\partial K}{\partial t} = \frac{\begin{array}{c}\left\{-2\rho g_a\mu\boldsymbol{u} + \frac{\mu^2\boldsymbol{u}^2}{K_I} + 2\frac{\rho\mu\boldsymbol{u}\partial\boldsymbol{u}}{\phi\ \partial t} + \rho\beta g_a T_r\mu\boldsymbol{u} - \rho\beta g_a T\mu\boldsymbol{u}\right\}\frac{\partial\phi}{\partial t} \\ +\left\{-2\rho g_a\mu\phi + \rho\mu\frac{\partial\boldsymbol{u}}{\partial t} + \rho\beta g_a T_r\mu\phi - \rho\beta g_a T\mu\phi\right\}\frac{\partial\boldsymbol{u}}{\partial t} + \rho\beta g_a\mu\phi\boldsymbol{u}\frac{\partial T}{\partial t} \\ + \left\{2g_a\mu\phi - \beta g_a T_r\mu\phi - \mu\frac{\partial\boldsymbol{u}}{\partial t} + \beta g_a T\mu\phi\right\}\rho c\boldsymbol{u}\frac{\partial p}{\partial t} - \rho\mu\boldsymbol{u}\frac{\partial^2\boldsymbol{u}}{\partial t^2}\end{array}}{\left\{2\rho g_a - \frac{\mu}{K_I}\boldsymbol{u} - \frac{\rho\partial\boldsymbol{u}}{\phi\partial t} - \rho\beta g_a T_r + \rho\beta g_a T\right\}^2} \qquad (12)$$

Now, equating Eq. (10) and (12), we can derive, $\frac{\partial\phi}{\partial t}$, which is substituted in Eq. (6). Therefore, the below equation (Eq. 13) is the final energy balance equation in reservoir flow for a single phase fluid when we consider ϕ variation with respect to time.

$$-\{\phi\rho c_p + (1-\phi)\rho_s c_{ps}\}\frac{\partial T}{\partial t} + T\{\phi\beta - (1-\phi)\rho_s c_{ps} c_s\}\frac{\partial p}{\partial t}$$
$$+\left(\frac{p + \rho_s c_{ps} T}{A_1 - A_2 A_3}\right)\left(A_4\frac{\partial\boldsymbol{u}}{\partial t} + A_5\frac{\partial p}{\partial t} + \rho\mu\boldsymbol{u}\frac{\partial^2\boldsymbol{u}}{\partial t^2} - \rho\beta g_a\mu\phi\boldsymbol{u}\frac{\partial T}{\partial t}\right)$$
$$= \rho c_p\boldsymbol{u}.\nabla T + \boldsymbol{u}.\nabla p - \beta T\boldsymbol{u}.\nabla p - k_t\nabla^2 T \qquad (13)$$

where,

$$A_1 = -2\rho g_a\mu\boldsymbol{u} + \frac{\mu^2\boldsymbol{u}^2}{K_I} + 2\frac{\rho\mu\boldsymbol{u}}{\phi}\frac{\partial\boldsymbol{u}}{\partial t} + \rho\beta g_a T_r\mu\boldsymbol{u} - \rho\beta g_a T\mu\boldsymbol{u}$$

$$A_2 = \left\{2\rho g_a - \frac{\mu}{K_I}\boldsymbol{u} - \frac{\rho}{\phi}\frac{\partial\boldsymbol{u}}{\partial t} - \rho\beta g_a T_r + \rho\beta g_a T\right\}^2$$

$$A_3 = 31 + 14926\,\phi + 191\times 10^{11}\,\phi^9$$

$$A_4 = -2\rho g_a\mu\phi + \rho\mu\frac{\partial\boldsymbol{u}}{\partial t} + \rho\beta g_a T_r\mu\phi - \rho\beta g_a T\mu\phi$$

$$A_5 = \left\{2g_a\mu\phi - \beta g_a T_r\mu\phi - \mu\frac{\partial\boldsymbol{u}}{\partial t} + \beta g_a T\mu\phi\right\}\rho c\boldsymbol{u}$$

Therefore, from Eq. (13), the final energy balance equation for the reservoir flow in terms of multiphase flow as

$$-\{\phi\textstyle\sum_f \rho_f\, c_{pf} + (1-\phi)\rho_s c_{ps}\}\frac{\partial T}{\partial t}$$
$$+T\{\phi\textstyle\sum_f \beta_f\, S_f - (1-\phi)\rho_s c_{ps} c_s\}\frac{\partial p_f}{\partial t}$$
$$+\{\textstyle\sum_f p_f + \rho_s c_{ps} T\}\times\frac{\sum_f\left(A_{4f}\frac{\partial\boldsymbol{u_f}}{\partial t} + A_{5f}\frac{\partial p}{\partial t} + \rho\mu\boldsymbol{u_f}\frac{\partial^2\boldsymbol{u_f}}{\partial t^2} - \rho\beta g_a\mu\phi\boldsymbol{u_f}\frac{\partial T}{\partial t}\right)}{\sum_f(A_{1f} - A_{2f}A_3)}$$
$$= \textstyle\sum_f \boldsymbol{u_f}.\rho_f c_{pf}\nabla T + \sum_f \boldsymbol{u_f}.\nabla p_f - T\sum_f \beta_f\boldsymbol{u_f}.\nabla p_f - k_t\nabla^2 T \qquad (14)$$

3.2. Model for Wellbore Flow

The variation of depth and time play a significant role in the wellbore fluid temperature. Many of the fluid properties such as density and viscosity influence the pressure drop. These fluid properties are greatly influenced by the fluid temperature. Therefore, the proper calculation of fluid temperature can be done by a proper energy balance on the fluid-wellbore system. The reservoir fluid, entering the wellbore, may contain gas, oil, and water. In such case, multiphase flow starts at the perforations.

The mass and energy balance equations for wellbore flow have been presented widely in petroleum engineering literature [1, 15 – 16]. Consider single phase or multiphase fluid flow along a wellbore as illustrated in Figure 2. Conservation of mass, momentum and energy balance should be observed in calculating wellbore flow pattern.

3.2.1. Conservation of Mass

The conservation of mass [1, 15 – 16] at the wellbore can be stated as the differential rate of mass flow into a wellbore minus the rate of mass flow out is equal to the rate of accumulation of mass in the area (Figure 2). Mathematically it is expressed as:

$$\frac{\partial(\rho_i\, y_i)}{\partial t} = -\frac{\partial(\rho_i\, v_i\, y_i)}{\partial x} + \frac{2\,\gamma\, y_{ei}}{r_W}\,\rho_{ei}\, v_{ei} \tag{15}$$

3.2.2. Conservation of Momentum

The conservation of momentum equation for a multi-phase fluid flow in a 1D system can be represented as the net force on the volume element to momentum change where pressure for each phase are assumed to be equal based on Figure 2 [1, 15 – 16] as:

$$\frac{\partial p}{\partial x} = -\frac{2\,\tau_W}{r_W} - \frac{\partial}{\partial t}(\rho_m\, v_m) - \frac{\partial}{\partial x}(\rho_m\, v_m^2) - \rho_m\, g\, \sin\theta \tag{16}$$

3.2.3. Conservation of Energy

Temperature difference between the wellbore fluid and the surrounding formation results in energy exchange. Several factors such as thermal convection and conduction heat transfer, and Joule-Thomson effects control this energy transfer [16]. In this study, the above mentioned effects are considered during the computation. In developing the energy balance equation, it is assumed that there is no heat source anywhere along the wellbore. The shaft work is negligible and no-slip boundary condition where the work to overcome wall friction is expected to be zero. Therefore,

$$\sum_i \frac{\partial(E_i\, y_i)}{\partial t} = -\sum_i \frac{\partial}{\partial x}[(E_i + p_i)v_i\, y_i] + \frac{2}{r_w} q_{ei}\,(1-\gamma) + \sum_i \frac{2}{r_w}[(E_{ei} + p_{ei})v_{ei}\,\gamma\, y_{ei}] + \sum_i \rho_i\, v_i\, y_i\, g\, \sin\theta \tag{17}$$

To solve the above governing equations, an inflow rate is determined by the pressure difference between reservoir pressure and wellbore pressure as $\int_{\Delta x} 2\,\pi\, r_w\,\gamma\, v_{ei}\, dx = J(p_r - p)$. The formation temperature is calculated using the relation $T_f = T_{ref} + G\,D$. The heat influx to the wellbore or heat flux from the formation is expressed as $q_{ei} = h\,(T_f - T)$. Neglecting the kinetic energy and substituting the definition of E_i, Eq. (17) reduces to:

$$\sum_i \frac{d}{dt}(\rho_i\, e_i y_i) = -\sum_i \frac{d}{dx}[(\rho_i\, e_i + p_i)v_i\, y_i] + \frac{2}{r_w} q_{ei}\,(1-\gamma) + \sum_i \frac{2}{r_w}[(\rho_{ei}\, e_{ei} + p_{ei})v_{ei}\,\gamma\, y_{ei}] + \sum_i \rho_i\, v_i\, y_i\, g\, \sin\theta \tag{18}$$

The relationship between internal energy and enthalpy can be expressed as $H = e + \frac{p}{\rho}$. Now substituting H in Eq. (18) yields:

$$\sum_i \frac{d}{dt}(H_i\,\rho_i - p_i)\, y_i = -\sum_i \frac{d}{dx}[H_i \rho_i v_i\, y_i] + \frac{2}{r_w} q_{ei}\,(1-\gamma) + \sum_i \frac{2}{r_w}[H_{ei}\rho_{ei}v_{ei}\,\gamma\, y_{ei}] + \sum_i \rho_i\, v_i\, y_i\, g\, \sin\theta \tag{19}$$

From mass balance Eq. (15), it is written as

$$\frac{d}{dx}(H_i\rho_i\, v_i\, y_i) = \rho_i\, v_i\, y_i \frac{dH_i}{dx} + H_i \frac{d(\rho_i\, v_i\, y_i)}{dx} = \rho_i\, v_i\, y_i \frac{dH_i}{dx} + H_i\left[\frac{2\,\gamma\, y_{ei}}{r_w}\,\rho_{ei}\, v_{ei} - \frac{d(\rho_i\, y_i)}{dt}\right] \tag{20}$$

When substitute Eq. (20) into Eq. (19), this becomes the form as:

$$\sum_i \left[\rho_{i\, y_i}\frac{dH_i}{dt} - \frac{d(p_i\, y_i)}{dt}\right] + \sum_i \rho_i\, v_i\, y_i \frac{dH_i}{dx} = \frac{2}{r_w}\sum_i \rho_{ei}\, v_{ei}\,\gamma\, y_{ei}(H_{ei} - H_i) + \sum_i \rho_i\, v_i\, y_i\, g\, \sin\theta + \frac{2}{r_w} q_{ei}\,(1-\gamma) \tag{21}$$

In Eq. (21), as enthalpy is a function of pressure and temperature, its derivative can be expressed as $\frac{dH_i}{dx} = c_{pi}\frac{dT_i}{dx} - c_{pi}\, C_{JTi}\frac{dp_i}{dx}$ and $\frac{dH_i}{dt} = c_{pi}\frac{dT_i}{dt} - c_{pi}\, C_{JTi}\frac{dp_i}{dt}$. Moreover, H_{ei} is the enthalpy of inflowing fluid and it is assumed that the pressure difference between inflowing fluid and wellbore is negligible. Then the difference in enthalpy can be written as $H_{ei} - H_i = c_{pi}(T_{if} - T_i)$.

Substituting the above relationships in Eq. (21), The final form of the Energy balance equation for wellbore flow reduces to:

$$\sum_i \left[\rho_{i\, y_i}\left(c_{pi}\frac{dT_i}{dt} - c_{pi}\, C_{JTi}\frac{dp_i}{dt}\right) - \frac{d(p_i\, y_i)}{dt}\right] + \sum_i \rho_i\, v_i\, y_i\left(c_{pi}\frac{dT_i}{dx} - c_{pi}\, C_{JTi}\frac{dp_i}{dx}\right) = \frac{2}{r_w}\sum_i \rho_{ei}\, v_{ei}\,\gamma\, y_{ei} c_{pi}(T_{if} - T_i) + \sum_i \rho_i\, v_i\, y_i\, g\, \sin\theta + \frac{2}{r_w} q_{ei}\,(1-\gamma) \tag{22}$$

4. Conclusion

The dependence of wellbore temperature upon phases, flow profile, fluid type, fluid properties, well deviation and Joule-Thomson effect are well described in this article. The developed temperature and pressure prediction models can be used to interpret the temperature changes along horizontal well. Thermal models are extended for single phase and multiphase fluid flow along an inclined and horizontal well. The models can be applied to investigate the thermal characteristics of single phase and multiphase fluid flow along wellbore. It can also be used for several important parameters, such as well deviation, Joule-Thomson effect, fluid phases, flow profile and so on. The most important use of these models are the prediction of production and injection profiles based on the given wellbore temperature profile.

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