

Investigation of significant factors of well temperature for gas-liquid two-phase flow in the under-balanced drilling operation

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ABSTRACT

Analysis of the drilling fluid temperature due to heat transfer of drilling fluid with the formation in under-balanced drilling operation is the main objective of this study. Gas-liquid two-phase flow model considering thermal interaction with the formation is used to numerically simulate a well with real dimensions. In the present study, the continuity, momentum, and energy equations are developed to compute the wellbore temperature profile. In this simulation, the effects of oil and gas production from the reservoir into the annulus and heat generated by viscous dissipation within the drilling fluid, heat generated by friction between the rotating drill string and the wellbore wall, and heat generated by the drill bit were included in the model. The results are validated with actual field data and also with two-phase flow model using the geothermal temperature gradient given in the literature. Comparisons of the present results show that two-phase flow numerical simulation with thermal consideration gives more accurate results compared to other models for the prediction of the bottom-hole pressure. Results show that the fluid temperature at the bottom-hole increases with increasing well depth, the flow rate of gas, and source terms consideration. Whereas the fluid temperature at the bottom-hole decreases with increasing liquid flow rate and specific heat of liquid and gas.

1. Introduction

Under-balanced drilling (UBD) is the drilling process in which the wellbore pressure is intentionally designed to be lower than the pressure of the formation being drilled. This under-balanced pressure condition allows the reservoir fluids (oil and gas) to enter the wellbore during drilling, thus preventing fluid loss and related causes of formation damage. UBD is one of the most important techniques to achieve high efficiency in drilling operations, extended bit life, reduced formation damage, minimized lost circulation, and earlier oil production and completion well without damaging the reservoir. UBD is the best available technology for low pressure or depleted reservoirs. In UBD, by injecting a gas such as nitrogen or carbon dioxide into the liquid drilling, bottom-hole pressure (BHP) can be precisely controlled in such a way that it is always lower than the formation pressure.

There are so many problems in the drilling operation, that the whole drilling operation becomes a precarious job. To minimize these problems, it is important to simulate before carrying out drilling operations. By simulation, downhole conditions can be predicted by representing certain key parameters. This will enable to approximate the temperature and pressure at a certain

depth. After getting such information, a proper rig, rig equipment, bit with the best compatible properties, and, etc. can be selected.

Heat transfer between drilling fluid with the formation (surrounding environment of the well) has been the subject of many experimental and numerical studies. Since the fluid properties depend on temperature, the calculation of this heat transfer is important in determining the profile of pressure and fluid temperature; therefore, accurate prediction of temperature profile will lead to a more accurate calculation of pressure distribution and BHP.

There are two major methods for estimating the temperature of the drilling fluid. The first is the analytical method. This method assumes constant fluid properties. Ramey [1] solved the energy equations analytically in a wellbore for the case of hot-fluid injection for enhanced oil recovery (EOR). He assumed that heat transfer inside the wellbore is steady state and that inside the formation is transient radial conduction which is known as the half-transient method. His solution permits the estimation of the fluid, tubing and casing temperature as a function of depth. Holmes and Swift [2] solved the energy equations analytically for the case of flow in the drill string and annulus with the half

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transient method. Arnold [3,4] solved the energy equations analytically for both the hot-fluid injection case and the fluid circulation case. He represented the transient nature of heat flow from the formation with a dimensionless time function that is independent of depth. Kabir et al [5] solved a similar set of equations, but for the case of reverse circulation (downward flow the annulus and upward flow in the drill string). They also assumed transient heat flow in the formation and evaluated a number of dimensionless time functions.

The second method of estimating the fluid temperature distribution during circulation involves allowing the fluid properties to vary with the temperature conditions. This method involves solving the governing energy equations numerically. Raymond [6] proposed the first numerical model for predicting fluid temperature profile during both transient and pseudo-steady-state conditions. Marshal et al [7] created a model to estimate the transient and steady-state temperatures in a wellbore during drilling, production and shut-in using a finite difference approach for single-phase flow. Song and Guan [8], by using a homogeneous model simulated circulating temperature and pressure of gas-liquid two-phase flow in deep water wells, they assumed that fluid flow and heat transfer inside the wellbore are steady states while a transient heat conduction takes places in the formation. The effects of the viscous flow energy, rotational energy, and drill bit energy were included in their model.

Perez-Tellez et al. [9, 10] proposed a mechanistic model to predict the gas-liquid two-phase flow pressure in the annulus, standpipe, and bottom hole. They developed a numerical method based on the drift-flux model to predict the parameters of gas-liquid two-phase flow. Khezrian et al. [11] simulated gas-liquid two-phase flow with a geothermal temperature gradient in the UBD operations by using a steady two-fluid model in the annulus while Shekari et al. [12] used a transient two-fluid model for numerical simulation of two-phase flow in the annulus of drilling well in UBD conditions. Using a numerical approach Ghobadpouri et al. [13] simulated gas-liquid two-phase flow in the annulus with a geothermal temperature gradient in the UBD operations. In this model, oil and gas production from the reservoir into the annulus in the UBD condition were considered. However, several factors, such as the effects of heat transfer between the wellbore and the surrounding formation on pressure distribution and the BHP, were not discussed in these models. Hajidavalloo et al. [27] compared the accuracy of the two-phase flow with thermal consideration with the two-phase flow with a geothermal temperature gradient, they found that the two-phase flow with thermal consideration model is more accurate for the estimate BHP.

As mentioned before, heat transfer in a wellbore has been the subject of many experimental, analytical, and numerical studies, which consider the effect of temperature in the single-phase or two-phase flow in UBD are very low and also the models presented are very simple. However, in the past numerical two-phase flow simulations, unlike the actual conditions, heat transfer of the well with the formation was not considered, whereas heat transfer affects the BHP and impose restrictions on the controlling parameters of UBD. Therefore, to generalize gas-liquid two-phase flow study in the well, the effect of heat transfer in the drilling must be carried out in order to get more accurate results for BHP prediction, pressure distribution, and thus having a successful UBD operation.

2. Physical problem and mathematical model

As shown in Fig. 1, in UBD operation, the liquid and gas (drilling mud) are pumped down through the drill string, passing through the drill bit, conveying the cuttings (solid particles), and then moves up in the annulus. In the annulus, the drilling fluids are mixed with the production fluids (gas, oil, or water). Therefore, under-balanced circulating systems are typically characterized by a complex flow of liquid mixture, gas mixture, and cuttings. Considering that thermophysical properties of the injected and produced gases are very close to each other, it can be assumed that injection gas and formation gas flow could be considered as a mixture which moves at the same speed. For the same reason, injection and formation liquids also are assumed as a mixture which flows at the same speed in the annulus. The two-fluid model which considers an individual velocity for each phase is used for simulation of gas-liquid two-phase flow in the annulus. The continuity and momentum equations of the two-fluid model were presented in the several papers such as Eyje and Flatten [16]. In this model, the gas phase is considered to be compressible and the liquid phase is assumed to be incompressible, assuming a one-dimensional flow in the wellbore, the viscous and turbulent shear stress effects are considered in friction coefficients between the phases and also between the phases and the walls. In this study, a steady one-dimension gas-liquid two-phase flow is considered at each time-step in the annulus, whereas heat transfer in the wellbore and heat conduction in the surrounding formation are considered to be transient since the temperature at any point will change with time during fluid circulation.

According to the above-mentioned assumptions, the continuity equations for each of the phases are as follows [16]:

$$\frac{d}{dx}(\alpha_G \rho_G u_G A) = 0 \tag{1}$$

$$\frac{d}{dx}(\alpha_L \rho_L u_L A) = 0 \tag{2}$$

The conservation of momentum equations for each of the phases are as follows [16]:

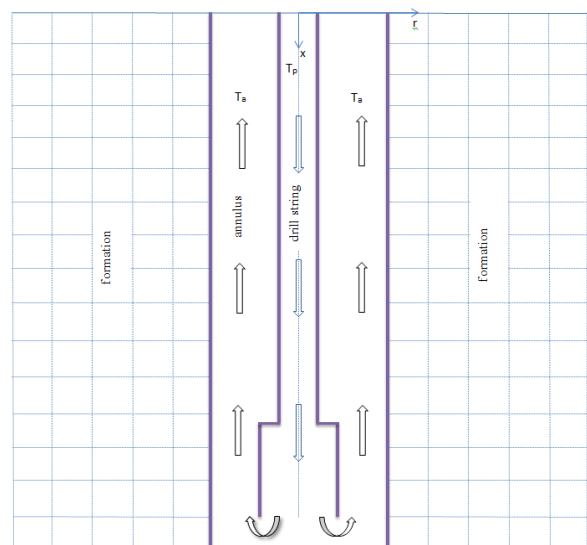


Figure 1. The schematic of geometry and discretized for fluid circulating in a wellbore

$$\frac{d}{dx}(\alpha_G \rho_G u_G^2 A) = -A \left(F_{iG} + F_{wG} + F_{gG} + F_{vG} + \alpha_G \frac{dP}{dx} \right) - \Delta P_{iG} \frac{d}{dx} \frac{A \alpha_G}{dx} \quad (3)$$

$$\frac{d}{dx}(\alpha_L \rho_L u_L^2 A) = -A \left(F_{iL} + F_{wL} + F_{gL} + F_{vL} + \alpha_L \frac{dP}{dx} \right) - \Delta P_{iL} \frac{d}{dx} \frac{A \alpha_L}{dx} \quad (4)$$

Where α is volume fraction; ρ is density; u is velocity; A is Area. G, L Subscript: stand for gas and liquid phases respectively. F_i is the force due to the interaction between the phases; F_w is wall friction force; F_g is a gravitational force, and F_v is a virtual mass force. ΔP_{iG} and ΔP_{iL} represents the pressure correction terms which are the difference between the pressure inside a phase and the interface phase pressure.

In this simulation, the flow pattern is determined based on the value of gas volume fraction [18] According to this approach, the flow regime is bubbly if the gas volume fraction is less than 0.2, from 0.2 to 0.3 transitions from bubble to slug take places, from 0.3 to 0.6915 a slug flow regime is dominant, between 0.6915 and 0.7915 transitions from slug to churn is hold and finally if the gas volume fraction is greater than 0.7915 the churn flow regime is dominant flow pattern. Also to calculate the F_{iG} and F_{iL} forces, we use the Ishii and Mishima [17] relations according to the flow pattern. To calculate the F_{wG} , F_{wL} , F_{vG} , and F_{vL} forces Drew et al. relations are used [19]. Due to the difference between phase velocity and interface velocity, their pressures are also different. This difference can be expressed by the pressure correction term. In this study, Bestion [20] correlation is used for the correction term as follow:

$$p_k - p_{ik} = \Delta p_{ik} = 1.2 \frac{\alpha_G \alpha_L \rho_G \rho_L}{\alpha_G \rho_L + \alpha_L \rho_G} u_G - u_L^2 \quad (5)$$

In order to close the equations, besides the conservation equations (Eqs. 1-4), two additional equations are required. One of the equations is an algebraic constraint and the other one is the gas equation of state. An algebraic constraint expresses that the sum of the volume fractions of the two phases must be one to fill the pipe's cross-section as follows:

$$\sum_k \alpha_k = \alpha_G + \alpha_L = 1 \quad (6)$$

The gas equation of state is as follows:

$$\rho_G = \rho_G(P_G, T_G) = \frac{M_G \times P}{8314 \times Z \times T} \quad (7)$$

Where Z is a gas compressibility factor that various correlations are available to calculate it. In this study, Dranchuk and Abu-Kassem correlation is used [21].

2.1. Heat Transfer in Wellbore

As shown in Fig.1, for a wellbore, three regions are identified as necessary in the heat transfer analysis namely drill string, annulus, and formation. The conservation of energy equation for a control volume inside the drill string is given as follows [22]:

$$2\pi r_p U_p [T_a(x, t) - T_p(x, t)] = \dot{m}_p C_p \frac{\partial T_p(x, t)}{\partial x} + \rho_p \pi r_p^2 C_p \frac{\partial T_p(x, t)}{\partial t} \quad (8)$$

Where r_p is the radius of drill string; T_p is temperature of the fluid inside the drill string; T_a is temperature of the fluid inside the annulus, both of which are function of the well depth and time; \dot{m}_p is the total mass flow rate of fluid inside the drill string; ρ_p, C_p are the density and specific heat of mixture inside the drill string, respectively.

The conservation of energy equation for a control volume inside the annulus is obtained by adding the heat source term to the Harris energy equation [22] as follows:

$$2\pi r_a U_a [T_f(r_a, x, t) - T_a(x, t)] - 2\pi r_p U_p [T_a(x, t) - T_p(x, t)] + \frac{S_a}{\Delta x} = \rho_a \pi (r_a^2 - r_p^2) C_a \frac{\partial T_a(x, t)}{\partial t} - \dot{m} C_a \frac{\partial T_a(x, t)}{\partial x} \quad (9)$$

Where r_a is the radius of the annulus; $T_f(r_a, x, t)$ is the temperature at the interface between formation and annulus; ρ_a, C_a are the density and specific heat of mixture inside the annulus, respectively, which are expressed as:

$$\begin{aligned} \rho_a &= \alpha_L \rho_L + \alpha_G \rho_G \\ C_a &= \alpha_L C_L + \alpha_G C_G \end{aligned} \quad (10)$$

U_a is the overall heat transfer coefficient between the annular fluid and the surrounding formation, U_p is the overall heat transfer coefficient between the fluid inside the drill string and fluid inside the annulus, as follows:

$$\frac{1}{U_p} = \frac{1}{h_p} + \frac{r_{pi}}{k_p} \ln \left(\frac{r_{po}}{r_{pi}} \right) + \frac{r_{pi}}{r_{po}} \frac{1}{h_a} \quad (11)$$

Where k_p is the thermal conductivity of drill pipe; r_{pi}, r_{po} are inner and outer radii of the drill pipe, respectively. Note that in Eq. 11, the second term on the right-hand side is the thermal resistance of the drill pipe, which is negligible, because of the high thermal conductivity of the drill pipe. Convection heat transfer coefficients can be calculated from Rezkallah and Sims relation, the accuracy of this relation was improved by modifying it as follows [23]:

$$\frac{h_{TP}}{h_L} = (1 - \alpha_G)^n \quad (12)$$

Where h_{TP} is the convection heat transfer coefficient for two-phase flow, the different exponent “ n ” values is according to the flow pattern. In this approach, $n = -0.76$ for the bubbly flow regime, $n = -0.62$ for the slug flow regime, $n = -0.43$ for the churn flow regime, and $n = -0.65$ for the annular flow regime. h_L is liquid single-phase heat transfer correlation developed by Sieder and Tate (1936):

$$\begin{cases} \text{Nu}_L = \frac{h_L d}{k_L} = 1.86 \left(\text{Re}_{SL} \cdot \text{Pr}_L \cdot \frac{d}{L} \right)^{\frac{1}{3}} & \text{Laminar } \text{Re}_{SL} \leq 2000 \\ \text{Nu}_L = \frac{h_L d}{k_L} = 0.027 \text{Re}_{SL}^{0.8} \text{Pr}_L^{0.33} & \text{Turbulent } \text{Re}_{SL} > 2000 \end{cases} \quad (13)$$

Where $Re_{sl} = \frac{\alpha_L \rho_L u_L d}{\mu_L}$ is Reynolds number. Also s_a is the internal heat generation (source term) inside the annulus which is given by Gao's model [24, 25] as follows:

$$S_a = \Delta P_2 Q_a + \dot{q}_{rot} \quad (14)$$

Where Q_a is the volume flow rate of fluid inside the annulus; ΔP_2 is the frictional pressure drop inside the annulus, and the \dot{q}_{rot} term can be determined by Gao's model using the following equation:

$$\dot{q}_{rot} = \Delta M \cdot \omega \quad (15)$$

Where ω is the rotary speed and ΔM is the torsion increment of torque along the axis direction which is given by the following equation:

$$\Delta M = 1.3617 \times \rho_p d_p^2 \Delta x \quad (16)$$

Where d_p is the outer diameter of the drill string.

2.2. Heat Transfer in formation

The conservation of energy equation in the formation is given as follows:

$$\frac{1}{r} \frac{\partial}{\partial r} \left(r \frac{\partial T_F}{\partial r} \right) = \frac{1}{\alpha_F} \frac{\partial T_F}{\partial t} \quad (17)$$

Where $\alpha_F = \frac{k_F}{\rho_F C_F}$ is the thermal diffusivity of the formation.

Initial condition:

$$T_F(r_a, x, 0) = T_s + T_G \cdot x \quad (18)$$

Boundary conditions:

At the interface of formation and annulus, the boundary condition can be expressed as follows:

$$-k_F \frac{\partial T_F(r_a, x, t)}{\partial r} + U_a T_F(r_a, x, t) = U_a T_a(x, t) \quad (19)$$

The boundary condition at far from the wall can be expressed as:

$$T_F(r = \infty, x, t) = T_s + T_G \cdot x \quad (20)$$

3. Solution method

First of all, in the steady-state flow, the temperature profile along the well can be estimated according to the geothermal temperature gradient, then continuity and momentum equations are reduced to four ordinary differential equations. These four equations besides an algebraic constraint of the volume fractions of the phases (Eq. 6) and the gas equation of state (Eq. 7) formed a set of six equations with six unknowns (2 volume fractions, 2 velocities, 1 density of gas and 1 pressure). Discretization of the governing equations results in a coupled nonlinear algebraic set of equations. Newton method is used for solving these equations. A forward first order approximation for the spatial derivatives has been used. Discretization of the governing equations is as Eq. 21 [26].

The boundary conditions are outlet wellhead pressure which is equal to the choke pressure, and the density of the gas at the wellhead which is obtained from the gas equation of state. The velocities, pressure, and volume fractions can be calculated from the

algorithm presented by Bratland [26] and Ghobadpouri [13] by using the Newton method.

$$F = \begin{bmatrix} F_1 \\ F_2 \\ F_3 \\ F_4 \\ F_5 \\ F_6 \end{bmatrix} = \begin{bmatrix} (\alpha_a \rho_a u_a A)_i - \dot{m}_{Gin} \\ (\alpha_L \rho_L u_L A)_i - \dot{m}_{Lin} \\ \left(\dot{m}_{Gin} (u_{G,i+1} - u_{G,i}) + \alpha_{G,i} A_i (P_{i+1} - P_i) \right) + \left(A \Delta P_{Gf} (\alpha_{G,i+1} - \alpha_{G,i}) - \Delta X A_i S_{G,i} \right) \\ \left(\dot{m}_{Lin} (u_{L,i+1} - u_{L,i}) + \alpha_{L,i} A_i (P_{i+1} - P_i) \right) + \left(A \Delta P_{Lf} (\alpha_{L,i+1} - \alpha_{L,i}) - \Delta X A_i S_{L,i} \right) \\ \alpha_a + \alpha_L - 1.0 \\ \rho_{G,i} - \rho(P_i, T_i) \end{bmatrix} = \begin{bmatrix} 0 \\ 0 \\ 0 \\ 0 \\ 0 \\ 0 \end{bmatrix} \quad (21)$$

The following is a summary of the steps taken in the numerical solution:

1. The initial conditions of the system (time $t = 0$) are specified. The initial temperature conditions in the wellbore and formation conform to the geothermal temperature gradient.
2. The temperature profile inside the drill string is evaluated using Eq. 8 and boundary condition at bottom-hole. It is necessary to guess the temperature of the annular at the current time step in order to evaluate the temperature profile inside the drill string. The initial guess is considered to be the temperature profile in the annulus at the previous time step.
3. Based on the newly evaluated temperature of the fluid inside the drill string, the temperature profile of annular fluid is evaluated using Eq. 9. Note that it is necessary to guess the temperature profile in the adjacent formation at the current time-step. The guess chosen is the temperature profile in the previous time step.
4. The formation temperature is then evaluated at the current time step based on the newly evaluated annulus temperature profile. The results of the procedure are then compared with the initial guesses. If the error is insignificant, the next time step is evaluated. If there is a significant error, the whole procedure is repeated with the current temperature profiles in the annulus and formation being used as the guesses. This procedure is repeated until the calculations are completed for the total circulation time.

4. Validation

In order to validate the numerical model in analyzing the gas-liquid two-phase flow with thermal consideration (2PFT model simulator) in the well during UBD operation, two real cases of available field data are simulated in the following sections. Comparison of the present results with Hassan and Kabir model (Holmes and Swift well dataset [2]), given in Table 1, is performed. Figure 2 shows the temperature profile of the annular fluid in the wellbore obtained after 44 hours of fluid circulation versus depth of well. It is found that very good results are obtained. The obtained temperature profile of annular fluid follows close trend similar to the Hassan and Kabir profile. The maximum deviation of the fluid temperature between the present results and those of Hassan and Kabir is about 0.3% in the bottom-hole.

Also, the two-phase flow with thermal consideration (2PFT model) is compared with the gas-liquid two-phase flow with a geothermal temperature gradient (2PF model) with the field data from Mexican well, Iride 1166, which was drilled in the Samaria-Iride oil and gas field (Perez-Tellez, [9]). The results are shown in Table 2. It is found that for the BHP prediction the average error of the 2PFT model simulation is approximately 0.2% less

than the 2PF model simulation and for the oil and gas production during UBD operation the relative deviation of the 2PFT model

simulation is approximately 1% less than the 2PF model simulation.

Table 1. well and operational parameters data from Holmes and Swift Well [2]

Well depth, ft	15000	Mud density, lbm/gal	10
Drill string OD, in.	6 5/8	Formation thermal conductivity, Btu/(ft.°F.hr)	1.3
Drill bit size, in.	8 3/8	Formation specific heat, Btu/(lbm.°F)	0.2
Circulation rate, bbl/hr	300	Formation density, lbm/ft3	165
Inlet mud temperature, °F	75	Surface earth temperature, °F	59.5
Mud thermal conductivity, Btu/(ft.°F.hr)	1.0	Average reservoir pressure, psi	3930
Mud specific heat, Btu/(lbm.°F)	0.4	Geothermal gradient, °F/ft	0.0127

Table 2. Comparison of 2PFT model with 2PF model and Field data

	Bottom-hole pressure (MPa)	Relative deviation (%)	Production (m3/day)	Relative deviation (%)
Field data Measured [10]	20.7	-	474	-
2PF model [14]	20.645	0.266	489	3.17
2PFT model	20.688	0.058	486	2.53

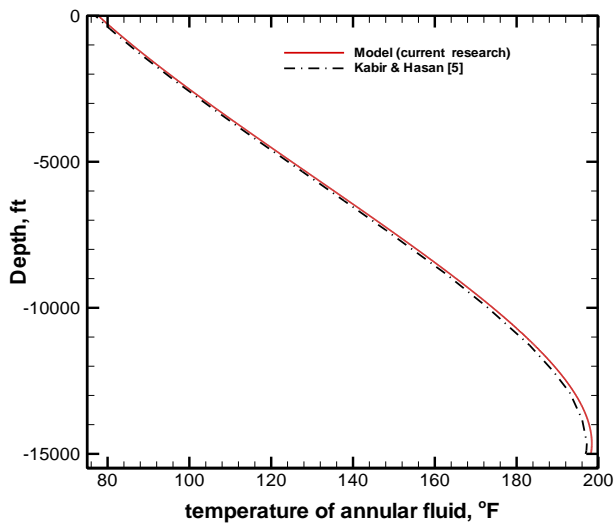


Figure 2. Comparison of the temperature profile of annular fluid obtained from this model with Kabir and Hassan [5]

5. Results and discussion

Figure 3 shows the variations of the temperature of the annular fluid at the wellhead and bottom-hole with circulation time for Muspac 53 well assuming inlet temperatures of 308K. As seen, the outlet temperature of the annular fluid at wellhead initially increases rapidly with time and followed by a gradual increase during the latter circulation period. Then it reaches an almost constant level of 313.7 K after 16 hours of fluid circulation. Whereas the temperature of the annular fluid at bottom-hole continually changes with time; a steady state condition is attained at least after 16 hours of the drilling mud circulation time.

Figure 4 shows the effect of internal heat generation (source terms) including viscous dissipation within wellbore, friction between the rotating drill string and the wellbore wall, and heat generation by the drill bit in the calculations after 16 hours of fluid circulation for Muspac 53 well (Perez-Tellez, [9]) data set given in Table 3. The plots in this figure confirm the necessity of including internal heat generation in any model that attempts to estimate temperature profiles., the magnitude of the difference

between the curves with and without internal heat generation obviously should not be ignored. Figure 4 also shows that ignoring about 5.5°C error in the bottom-hole temperature.

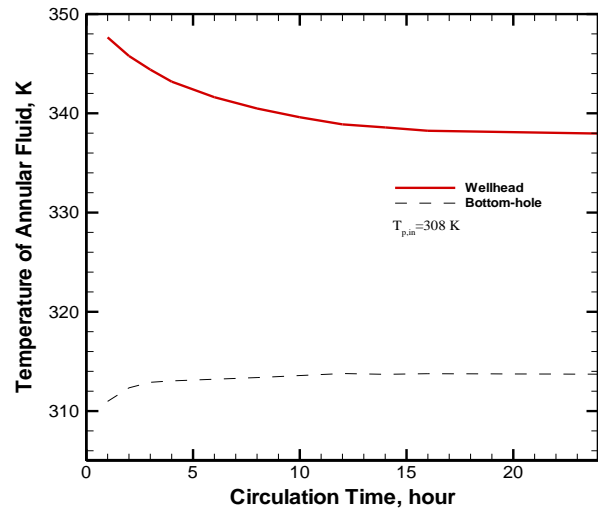


Figure 3. Effect of circulating time on the temperature of the annular fluid at wellhead and bottom-hole

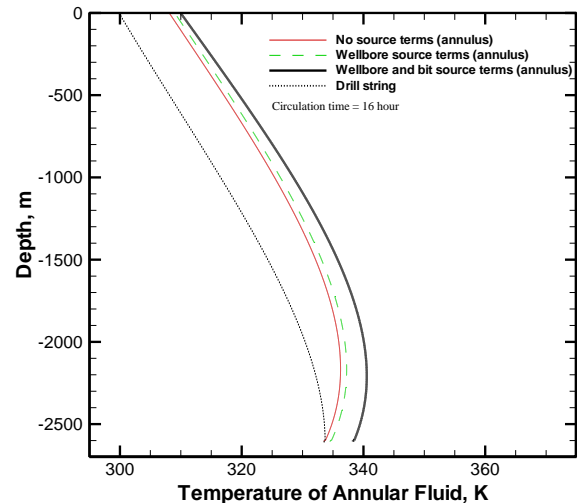


Figure 4. Effect of internal heat generation on the temperature of the annular fluid

Table 3. Muspac 53 Well [9]

Muspac 53's well geometry			
Depth, m	Drill string outer diameter (mm)	Inner casing diameter (mm)	
0-2555	88.9	152.5	
2555-2597	120.7	152.5	
2597-2614	120.7	149.2	
Muspac 53's operational parameters and flow test data			
Simulated depth, m	2605	Gas flow rate in standard condition, m ³ /min	15.008
Surface temperature, K	301.15	Gas molecular weight	28.02
Geothermal gradient, K/m	0.0283	Liquid flow rate, m ³ /min	0.503
Liquid density, kg/m ³	940	Choke pressure, MPa	0.31

Variations of the temperature profile of annular fluid with well depth for the different specific heat of liquid and gas after 16 hours of fluid circulation for Muspac 53 well are shown in Figs. 5 and 6. It can be seen in these figures, the temperature profile of annular fluid is strongly depended on the specific heat of gas and liquid. We conclude from Eq.10 that, the specific heat of the mixture increases with increasing specific heat of liquid or gas. It can be seen in the Figs. 5 and 6, the bottom-hole temperature and maximum temperature of annular fluid decrease with increasing specific heat of mixture but temperature of the annular fluid at the wellhead increases with increasing specific heat of mixture. The plots in the Figs. 5 and 6 show that the temperature of the annular fluid at the wellhead increased 4.3°C and temperature of the annular fluid at the bottom-hole decreased 9.8°C with doubling the specific heat of liquid, meanwhile, the temperature of the annular fluid at the wellhead increased 4.7°C and temperature at the bottom-hole decreased 12.8°C with doubling the specific heat of gas. We know that the specific heat of gas is smaller than that of liquid. Therefore, the effect of increasing specific heat of gas on the specific heat of mixture is higher than that of increasing specific heat of liquid.

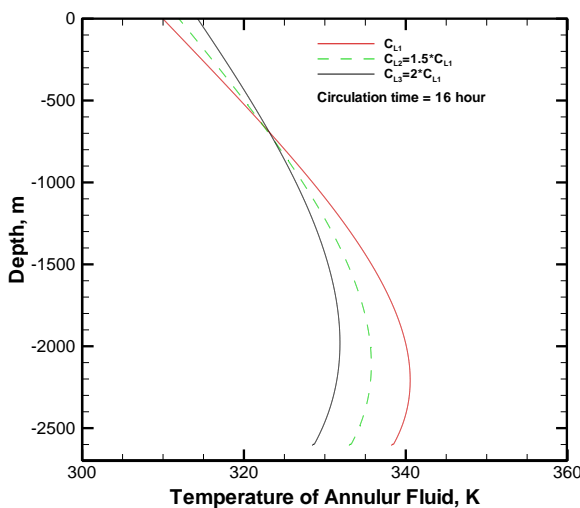


Figure 5. Effect of the specific heat of liquid on the temperature of annular fluid

Figures 7 and 8 show the effects of flow rates of gas and liquid after 16 hours of fluid circulation for Muspac 53 well. As it can be seen in these figures, the temperature profile of annular

fluid is strongly depended on flow rates of gas and liquid. Because the gas and liquid velocities depend on the flow rates of gas and liquid. Figure 7 shows the temperature of the annular fluid at the wellhead increases and bottom-hole temperature decreases with increasing the flow rate of the liquid. Whereas bottom-hole temperature increases with increasing gas flow rate and temperature of the annular fluid at the wellhead decrease with increasing gas flow rate. The plots in the Fig. 7 also show that the bottom-hole temperature decreases from 338.2 K to 333 K when the flow rate of liquid increases from 0.503 m³/min to 0.603 m³/min, and temperature of the annular fluid at the wellhead increased from 310 K to 314.3 K for flow rates of liquid 0.503 m³/min to 0.603 m³/min respectively. By increasing the flow rate of the liquid phase, gas velocity and liquid velocity are decreased along the entire annulus [13]. Therefore, the convection heat transfer coefficient between the drilling fluid and formation decreases with the increasing flow rate of the liquid. Consequently, the difference between the temperature of annular fluid and formation increases with increasing flow rate of the

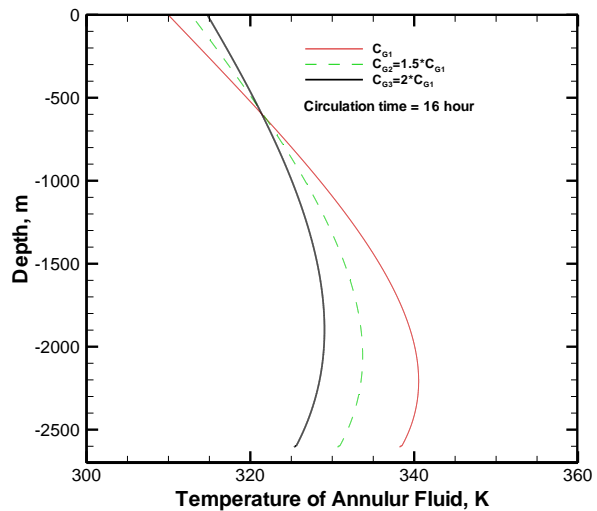


Figure 6. Effect of the specific heat of gas on the temperature of the annular fluid

As shown in Fig. 8, the temperature of the annular fluid at the bottom-hole increases with increasing the flow rate of gas. Because of, by increasing the flow rate of gas, unlike liquid, both the gas and liquid velocities are increased [13]. Therefore, the

convection heat transfer coefficient between the surrounding formation and drilling fluid is increased. Consequently, the difference between the temperature of the formation and annular fluid temperature decreases with increasing the flow rate of the gas. Figure 8 shows the temperature of the annular fluid at the wellhead decreased from 310 K to 308.1 K as flow rates of gas increases from of 15 m³/min to 20 m³/min. Furthermore, the bottom-hole temperature increases from 338.2 K to 346.3 K.

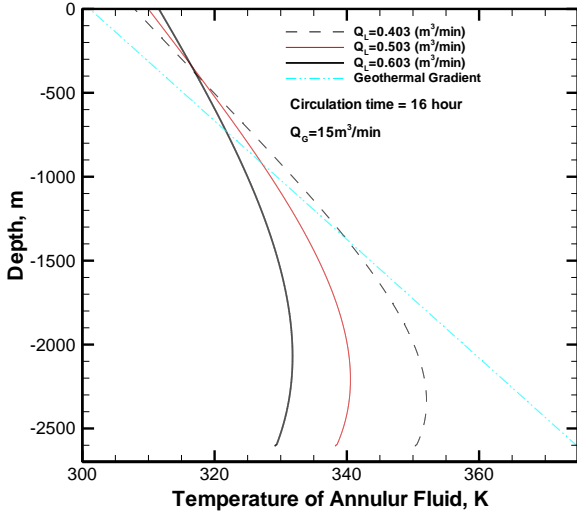


Figure 7. Effect of the flow rate of liquid on the temperature of annular fluid

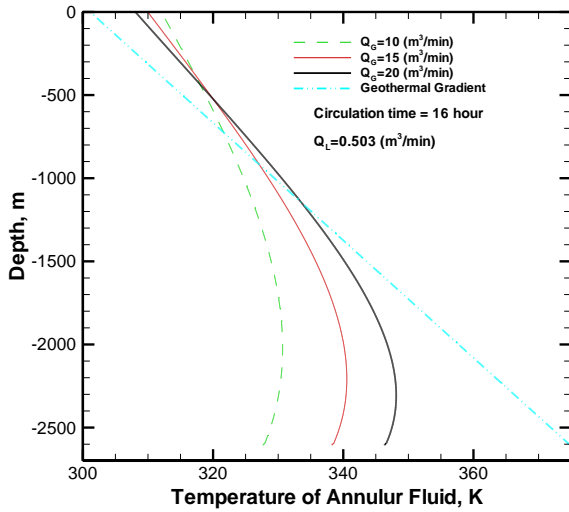


Figure 8. Effect of the flow rate of gas on the temperature of the annular fluid

Variations of the temperature profile of annular fluid with well depth for the different thermal conductivity of liquid after 16 hours of fluid circulation for Muspac 53 well is shown in Fig. 9. As shown in this figure, the temperature of the annular fluid at the bottom-hole increased about 4°C and temperature of the annular fluid at the wellhead decreased about 1°C with doubling the thermal conductivity of the liquid.

Figure 10 shows the effects of the well depth on the temperature profile of annular fluid after 16 hours of fluid circulation for Muspac 53 well. As it can be seen in this figure temperature profile of annular fluid is strongly depended on the depth of the wellbore. Figure 10 shows the temperature of the annular fluid at bottom-hole increases with increasing depth of the well. Because of drilling fluid in contact with these hot

formations as drilled deeper, it will receive more heat flux from the hot surrounding formations. Figure 10 also shows that drilling deep formation not only affects the temperature of annular fluid close to bottom-hole but the temperature of the annular fluid close to wellhead is also raised.

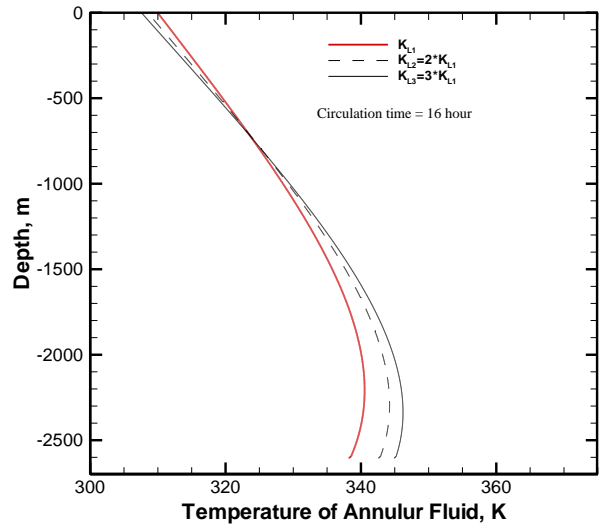


Figure 9. The sensitivity of temperature of the annular fluid to the thermal conductivity of the liquid

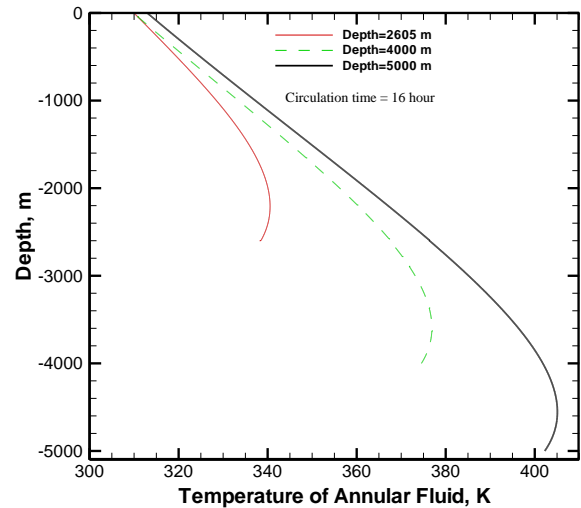


Figure 10. Effect of the well depth on the temperature of the annular fluid

Figure 11 shows the effect of oil and gas production from the reservoir into the annulus on the temperature profile of annular fluid after 16 hours of fluid circulation for Irade 1166 well. 16. As shown in this figure, the temperature of the annular fluid at the bottom-hole increases with oil and gas production. Figure 11 also shows that ignoring the effect of oil and gas production will cause more than 11°C error in the bottom-hole temperature.

6. Conclusions

In this paper, a numerical method based on the two-fluid model is developed to study behaviors of temperature during a gas-liquid two-phase flow with thermal consideration along the annular space of the drilling well in the UBD operation. Internal heat generations in the conservation of energy equation are considered in this simulation. From this study, we conclude that:

1- The performance of the gas-liquid two-phase with thermal consideration simulator (2PFT model) is compared with the two-phase flow with a geothermal temperature gradient (2PF model) in predicting the bottom-hole pressure (BHP). Results for Irde 1166 well show that the accuracy of the 2PFT model is better than the 2PF model in predicting the BHP and the oil and gas production during UBD operation.

2- The fluid temperature at the bottom-hole decreases with increasing flow rate of the liquid and specific heat of liquid and gas.

3- The source terms and oil and gas production have an important effect on the thermal distribution of fluid.

4- The thermal conductivity of liquid and formation does not have a significant effect on the variations of annular fluid temperature.

5- The fluid temperature at the bottom-hole increases with increasing depth of well, flow rate of gas, and internal heat generation consideration.

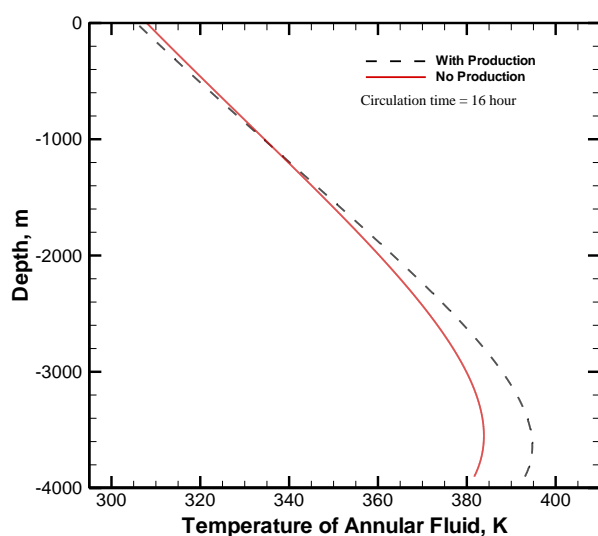


Figure 11. Effect of oil and gas production on the temperature of the annular fluid

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