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Thermal simulation of two-phase flow in under-balanced drilling operation with oil and gas production

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ABSTRACT

The accurate prediction of wellbore temperature distribution helps to accurately estimate well pressure profile and bottom-hole pressure (BHP) which is important in the under-balanced drilling (UBD) operation. In this paper effect of temperature variation due to heat transfer of drilling fluid with the formation and also oil and gas production from the reservoir into the annulus in under-balanced drilling condition were investigated. Gas-liquid two-phase flow model considering thermal interaction with the formation is used to numerically simulate a well with real dimensions. Based on drilling fluids flow and heat transfer characteristics in wells, conservations of mass and momentum and energy equations have been developed to compute BHP and wellbore temperature and pressure profile. After temperature and pressure validation of the numerical model, the effect of heat transfer between drilling fluid inside the well and the formation was considered on the pressure distribution and bottom-hole pressure. The results of two-phase flow, considering thermal effect gives better results compared to two-phase flow with geothermal temperature distribution analysis and better accuracy in comparison with other models.

1. Introduction

The increase in oil prices during the past years has led to re-investing in reservoirs that were not previously economical to produce. Also, many reservoirs have been partially depleted and the current industry trend is to infill drill or sidetrack abandoned reservoirs; seeking new reserves. The existence of such reservoirs has led to the extensive use of under-balanced drilling (UBD), because it minimizes formation damage. UBD is the best available technology for low pressure or depleted reservoirs. A UBD operation is considered a success when it achieves the required under-balanced pressure. Different UBD techniques may not achieve the required wellbore pressures. For example, many two-phase drilling fluids have been used extensively, but tend to generate high bottom-hole pressure.

The heat transfer inside the well during drilling operations is due to the difference in fluid temperature with the formation (surrounding environment of the well). Since the fluid properties depend on temperature, the calculation of this heat transfer is important in determining the distribution of fluid temperature; therefore, accurate prediction of temperature distribution will lead to a more accurate calculation of pressure distribution and bottom-hole pressure.

The evaluation of the temperature behavior and the heat transfer governing equations in a wellbore were solved by Ramey (1962), Raymond (1969), Holmes and Swift (1970), Wooley (1980), and Arnold (1990) [1-5]. In 1998 Garcia et al. [6] developed a thermal simulator for estimating wellbore temperature profile for single-phase flow. In 1992 Hasan and Kabir [7] proposed a mechanistic model to predict the volume fraction of gas for the upward gas-liquid two-phase flow in the annulus. In 2001 Fan et al. [8] developed a computer program for predicting the behavior of multiphase fluid flow during the UBD operations. Governing equations in this research are mass conservation equations separately for each phase and a general momentum equation for the mixture. In this research, the velocity difference between phases was neglected. In 2002 Guo and Ghalambor [9] used a mechanistic approach to determine the acceptable range of the injected liquid and gas to ensure correct UBD operation. Restrictions considered in this study were including the BHP and correct cutting transport. In 2003 Perez-Tellez and Perez-Tellez et al. [10, 11] proposed a mechanistic model to predict the gas-liquid two-phase flow pressure in the annulus, standpipe, and bottom

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hole. They developed a numerical method based on the drift-flux model to predict the parameters of gas-liquid two-phase flow. In 2006 Ping et al. [12] investigated the two-phase flow in the UBD operation by using Hasan and Kabir model and also Ansari model. They concluded that by doing modifications on the Ansari model, this model is more accurate than the Hasan and Kabir model to predict the BHP in the UBD operations. In 2009 Apak and Ozbayoglu [13] made a simulator using finite element method to calculate the distribution of heat in the wellbore for single-phase flow. In 2016 Ghobadpouri et al. [14] Simulated gas-liquid two-phase flow in the UBD operations by using a two-fluid model with geothermal temperature distribution (The geothermal gradient is the rate of increase in temperature per unit depth in the earth, It is caused by the continuous heat flow outward from the interior of the earth [15]).

As mentioned, in the drilling, many studies have been carried out on the effect of temperature in the single-phase flow but research on the effect of temperature the two-phase flow during UBD drilling is very low and also the models presented are very simple. Also in the most numerical simulation, unlike the actual conditions, the existence of heat transfer in well with the formation, is not considered in the well. While heat transfer in well affect the BHP and impose restrictions on the controlling parameter, therefore simulation of gas-liquid two-phase flow with thermal consideration in the well is necessary to get a better BHP prediction, pressure distribution and thus having a successful UBD operation.

2. Model Formulation

In UBD operations can be observed in Fig. 1, drilling fluids (liquid and gas) are pumped down through the drill string, passing the bit, and then move up in the annulus. Within the annulus, drilling fluids are mixed with rock cuttings and production fluids (gas, oil, or water). Therefore, underbalanced hydraulic circulating systems are typically characterized by the complex flow of two or more phases (liquid mixture, gas mixture, and solid cuttings). Considering that hydraulic properties between the injected and produced gases are relatively, it is 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 liquid and formation liquids also are assumed as a mixture which flow at the same speed in the wellbore annulus. Bearing in mind these assumptions, the multiphase underbalanced hydraulic circulation system may be simplified to a two-phase flow system in which only a mixture of liquid and gas flow.

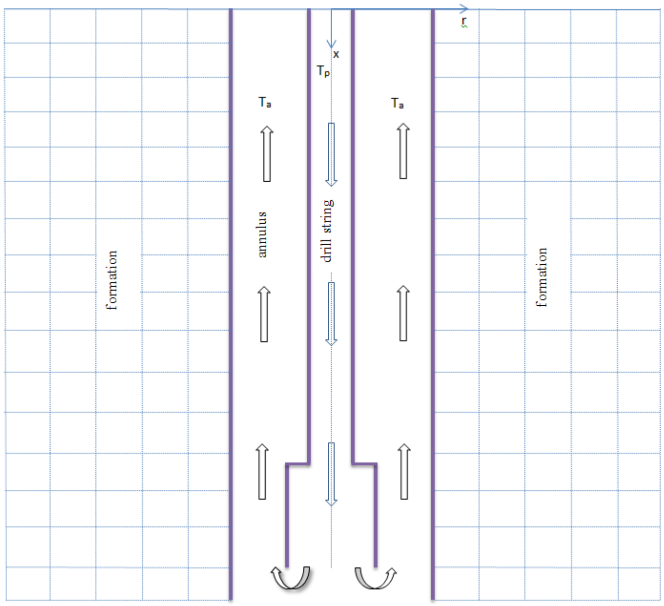

Figure 1. Geometry and discretized for fluid circulating in a wellbore

The two-fluid model which considers each phase has its own velocity is used for simulation of gas-liquid two-phase flow in the well. Governing equations of the multi-fluid model were presented in the several papers such as Evje and Flatten [16]. The gas phase is considered to be compressible and the liquid is assumed incompressible. By assuming one-dimensional flow in the well, the viscous and turbulent shear stress effects are considered in friction coefficients between the phases and also between walls and phases.

The continuity equations for each phase 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 phase are as follows, [16]:

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

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

where in equations 1-4, α is volume fraction, ρ is density, u is velocity, A is Area. Subscript: G indicates gas phase and L indicates liquid phase. F_i is the force due to the interaction between the phases, F_w is friction force from the wall, F_g is a gravitational force, and F_v is a virtual mass force. ΔP_{iK} (K=G, L) represents the pressure correction term which is the difference between the pressure inside a phase and the interface phase pressure.

To calculate the F_{iG} and F_{iL} forces, we use the Ishii and Mishima [17] relations according to the two-phase flow pattern, In this paper, the flow pattern is distinguished based on the value of gas volume fraction Hatta et al. [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, From 0.3 to 0.6915 slug regime, between 0.6915 and 0.7915 transitions from slug to churn and for churn regime the gas volume fraction is greater than 0.7915. Relations are used to calculate the F_{wG} and F_{wL} forces and the Drew et al. [19] also relations are used to calculate the F_{vG} and F_{vL} forces. Because of the difference between the phase velocity and the interface velocity, their pressures are also different. This difference can be expressed by the pressure correction term. In this paper, Bestion [20] formula is used for the correction term.

Besides the conservation equations, two additional equations are required to close the system of equations. One of the equations is an algebraic constraint and the other is 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:

$$\sum_k \alpha_k = \alpha_G + \alpha_L = 1 \tag{5}$$

The gas equation of state as follows:

$$\rho_G = \rho_G (P_G, T_G) = \frac{M_G \times P}{8314 \times Z \times T} \tag{6}$$

In Equation 6, Z is a gas compressibility factor that various formulas are available to calculate it. In this study, Dranchuk and Abu-Kassem (1975) formula is used [21].

2.1. Heat Transfer in Wellbore

For a wellbore, three regions were identified as necessary in the heat transfer analysis namely drill string, annulus, and formation shown in Fig.1. Energy conservation equation for a control volume inside the drill string is given as follows (Equation (7) is obtained by adding the term heat source term to the Harris energy equation [22]):

$$\begin{aligned}&2\pi r_p U_p \left[\mathrm{T}_a(z,t) - \mathrm{T}_p(z,t) \right] + \frac{S_1}{\Delta z} = \\ &\dot{m} C_{fl} \frac{\partial \mathrm{T}_p(z,t)}{\partial z} + \rho \pi r_p^2 C_{fl} \frac{\partial \mathrm{T}_p(z,t)}{\partial t}\end{aligned} \tag{7}$$

In this equation, T_p is the fluid temperature inside the drill string, T_a is the temperature of the fluid in the annulus, both of which are function of the well depth and time, $\dot{m}$ is the mass flow rate of drilling fluid, C_{fl} is heat capacity of drilling fluid, r_p is the radius of drill string pipe, z is the well depth and S_1 is the heat source caused by the heat generated by the loss of frictional fluid pressure inside the drill string. U_p is the total transfer coefficient heat between the fluid temperature inside the drill string and fluid inside the annulus. The heat transfer coefficient caused by gas-liquid two-phase flow in a circular pipe is calculated according to Kim [23].

Pressure loss caused by the gas-liquid two-phase flow is considered to be as a frictional source of internal heat generation for nodes above the drill bit. In this paper Li et al. formula is used [24]:

$$S_1 = \Delta P_1 . Q_1 \tag{8}$$

Where Q_1 is the volume flow rate of gas-liquid fluid inside the drill string, and ΔP_1 is the frictional pressure drop fluid inside the drill string.

Energy conservation equation for a control volume inside the annulus is written as follows (Equation (9) is obtained by adding the term heat source term to the Harris energy equation [22]):

$$\begin{aligned}&2\pi r_a U_a \left[\mathrm{T}_F(r_a, z, t) - \mathrm{T}_a(z,t) \right] - \\ &2\pi r_p U_p \left[\mathrm{T}_a(z,t) - \mathrm{T}_p(z,t) \right] + \frac{S_2}{\Delta z} = \\ &\rho \pi \left(r_a^2 - r_p^2 \right) C_{fl} \frac{\partial \mathrm{T}_a(z,t)}{\partial t} - \dot{m} C_{fl} \frac{\partial \mathrm{T}_a(z,t)}{\partial z}\end{aligned} \tag{9}$$

In this equation, T_F is formation Temperature, r_a the annular radius, U_a heat transfer coefficient across annulus/formation interface and S_2 is the heat source inside the drill string is given by Gao's model [25] as follows:

$$S_2 = \Delta P_2 . Q_2 + \dot{q}_{rot} \tag{10}$$

Where Q_2 is the volume flow rate of fluid inside the annulus, ΔP_2 is the frictional pressure drop fluid inside the annulus, and $\dot{q}_{rot}$ term can be determined by using the Gao's model following equation:

$$\dot{q}_{rot} = \Delta M . \omega \tag{11}$$

Where ω is the rotary speed and ΔM is the torsion increment of torque along the axis direction is written as follows:

$$\Delta M = 1.3617 \times \rho_a d_p^{\,2} \Delta z \tag{12}$$

Where ρ_a is the density of the fluid mixture inside the annulus and d_p is the outer diameter of the drill string.

2.2. Heat Transfer in formation

Energy conservation equation in the formation is given as follows:

$$\frac{1}{r} \frac{\partial}{\partial r} \left(r \frac{\partial T_F}{\partial r} \right) = \frac{1}{\alpha_F} \frac{\partial T_F}{\partial t} \tag{13}$$

And energy conservation equation about a small control volume within the formation adjacent to the annulus is given as follows:

$$\begin{aligned}&-2\pi r_a U_a \left[T_F(r_a, z, t) - \mathrm{T}_a(z,t) \right] + \\ &2\pi r_a k_F \left[\frac{\partial T_F(r_a, z, t)}{\partial r} \right] = 2\pi r_a \Delta r \, \rho C_F \frac{\partial T_F(r_a, z, t)}{\partial t}\end{aligned} \tag{14}$$

Initial condition:

$$T_F(r_a, z, 0) = T_G \quad \text{(The geothermal temperature)} \tag{15}$$

Boundary conditions:

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

$$-k_F \frac{\partial T_F}{\partial r} + U_a \mathrm{T}_F = U_a \mathrm{T}_a \tag{16}$$

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

$$T_F\left(r = \infty, z, t\right) = T_G \quad \text{(The geothermal temperature)} \tag{17}$$

3. Solution method

By considering the steady-state condition (after 16 hours of circulation) for continuity and momentum equations, first, the temperature gradient along the well can be assumed to follow the geothermal gradient then continuity and momentum equations are reduced to four ordinary differential equations. These equations besides an algebraic constraint of the volume fractions of the phases (Eq. 5) and the gas equation of state (Eq. 6) formed a system of six equations with six unknowns, namely 2 volume fractions, 2 velocities, 1 gas densities and 1 pressure. After discretizing, the governing equations will be changed to a coupled nonlinear algebraic system 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 follows (Bratland) [26]:

$$F = \begin{bmatrix} F_1 \\ F_2 \\ F_3 \\ F_4 \\ F_5 \\ F_6 \end{bmatrix} = \begin{bmatrix} (\alpha_G \rho_G u_G A)_i - K_{Gin} \\ (\alpha_L \rho_L u_L A)_i - K_{Lin} \\ \begin{pmatrix} K_{Gin}\left(u_{G,i+1} - u_{G,i}\right) + \alpha_G A_i \left(P_{i+1} - P_i\right) + \\ A \Delta P_{iG}\left(\alpha_{G,i+1} - \alpha_{G,i}\right) - \Delta X . A_i . S_{G,i} \end{pmatrix} \\ \begin{pmatrix} K_{Lin}\left(u_{L,i+1} - u_{L,i}\right) + \alpha_L A_i \left(P_{i+1} - P_i\right) + \\ A \Delta P_{iL}\left(\alpha_{L,i+1} - \alpha_{L,i}\right) - \Delta X . A_i . S_{L,i} \end{pmatrix} \\ \alpha_G + \alpha_L - 1.0 \\ \rho_{G,i} - \rho\left(P_i, T_i\right) \end{bmatrix} = \begin{bmatrix} 0 \\ 0 \\ 0 \\ 0 \\ 0 \\ 0 \end{bmatrix} \tag{18}$$

The boundary conditions that must be applied to the system of equations (Eq. 18) include wellhead pressure which is equal to the choke pressure and the gas density which is gained from the gas equation of state by using pressure and temperature at the wellhead. We can use constants mass flow rates of liquid, and gas for defining the inlet boundary conditions. For calculation of the velocities and volume fractions boundary conditions and solving the problem by using Newton method is used. At the inlet to the drill string: the inlet temperature is the surface temperature and at the inlet to the annulus at the bottom hole: Temperature at the inlet to the annulus is taken as the outlet at the bottom of the drill string.

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

1. The initial conditions of the system are specified (time t = 0). The initial temperature conditions in the wellbore and formation conform to the formation geothermal gradient.

2. The temperature profile in the drill string is evaluated first using Eq. 7. It is first necessary to guess the temperature profile in the annulus at the current time step in order to evaluate the drill string. The initial guess is taken to be the temperature profile in the annulus at the previous time step.

3. Based on the newly evaluated drill string temperature, the annular temperature profile is evaluated using Eq. 8. Note that it is necessary to guess the temperature profile in the immediate adjacent formation at the current time-step. The guess chosen is the temperature profile in the previous time step.

4. The temperature profile in the formation 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. Results and discussion

To test the independence of the network, simulation of the Mexican well, Iride 1166, which was drilled in the Samaria-Iride oil and gas field (Perez-Tellez, [10]), given in table 1 have been performed. In this well as the bottomhole pressure becomes less than the average reservoir pressure, oil and gas will enter into the wellbore during drilling. Figure 2 shows the results for this well. As shown in Fig.2, the production value for nodes greater than 3500 is almost constant and no longer changes, so the value for this well (with 3902-meter depth) is 3902 nodes.

4.1. Validation

To evaluate the numerical model in analyzing the gas-liquid two-phase flow with thermal consideration (TPFT model simulator) in the well during under-balanced drilling operations, two real cases of available field data are simulated in the following sections.

Temperature model validation

In order to validate the thermal numerical model, comparison of the present results with Hassan and Kabir's data set (Holmes and Swift Well), given in table 2, is performed. Figure 3 shows the fluid temperature profile in the annulus obtained after 44 hours of circulation versus well depth. It is found that very good results are obtained. The obtained fluid temperature profile in the annulus follow close trend similar to the Hassan and Kabir profile. The maximum deviation of the fluid temperature in the bottom-hole between present results and Hassan and Kabir ones is about 0.5%.

Table 1. well Iride 1166 [10]

Iride 1166's well geometry			
Depth, m	Drill string outer diameter (mm)	Inner casing diameter (mm)	
0-3764	88.9	168.3	
3764-3901	120.7	168.3	
Iride 1166's operational parameters and flow test data			
Simulated depth, m	3902	Gas (nitrogen) molecular weight	28.02
Surface temperature, K	302.4	Nitrogen injection flow rate, m3/min	10
Geothermal gradient, K/m	0.0306	Nitrogen specific gravity	0.97
Drilling fluid density, kg/m^3	949	Liquid injection flow rate, m^3/min	0.4542
		Choke pressure, MPa	0.207
Iride 1166's flow test data			
Oil flow rate, m^3/day	474	Oil density, m^3/day	805.6
Maximum oil flow rate, m^3/day	1275.2	Gas oil ratio, m^3/ m^3	287.3
API gravity of the oil	44	Natural gas molecular weight	18.83

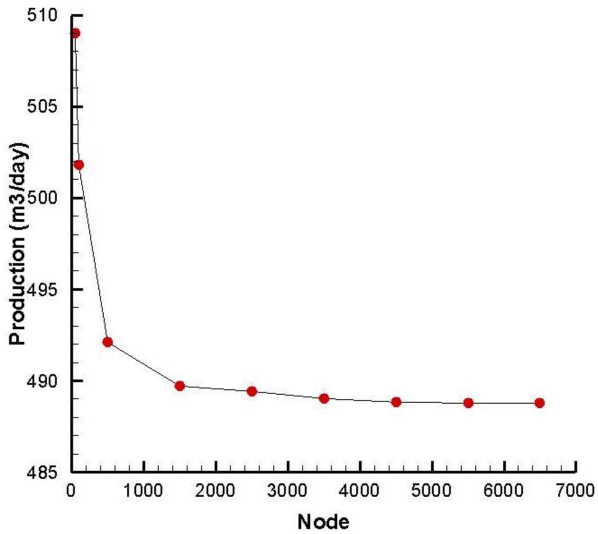

Figure 2.grid study

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

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/ft^3	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

Pressure model validation

Bottom-hole pressure (BHP) is the most important parameter in the UBD operation, where its accurate estimation and better control, is the main goal of all simulations. In the following, the effects of drilling fluid heat transfer with the formation on this parameter are presented.

Predicted pressures using the TPFT model simulator have been compared with the field data for Muspac 53 well and Iride 1166 well (Perez-Tellez, [10]) data set, given in tables 1, 3.

Figure 4 shows the pressure distribution along the annulus versus depth well for Muspac 53 well, which were simulated using different approaches. It is observed that two-phase flow with thermal consideration (TPFT model) analysis gives relatively better results compared to two-phase flow with geothermal temperature (TPF model) distribution analysis for BHP. Also, this approach has better accuracy compared to the most WELLFLO software models which is using different mechanistic models such as Biggs & Brill. Comparison of the accuracy of two-phase flow with thermal consideration and two-phase flow with geothermal temperature distribution simulations with the field data for Muspac 53 well show that for BHP prediction the error is approximately 5% less.

Figure 5 shows the effect of circulation time on annulus drilling fluid (mud) temperature profile for Iride 1166 well. It is illustrating that the temperature of fluid drops continuously with increasing circulation time. For even 2 h of circulation, the fluid temperature trend in the annulus deviates from the surrounding formation temperature. When it circulates for 16h, the formations are cooled enough and the trend goes away from the formation temperature. Also, the plots in Fig.5 show the fluid temperature in the annulus does not acquire maximum temperature at the bottom of the hole. In the case studied, the maximum fluid temperature for 2 h of circulation occurs at 3645 m with the total depth of 3901 m. This point will tend to move up as the circulation time increase.

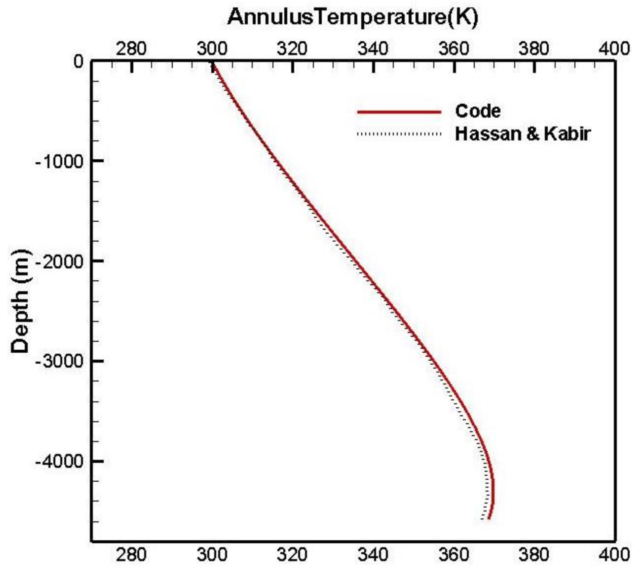

Figure 3. Comparison of annulus temperature distribution obtained from TPFT model with Hassan and Kabir model

Table 3. Muspac 53 Well [10]

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

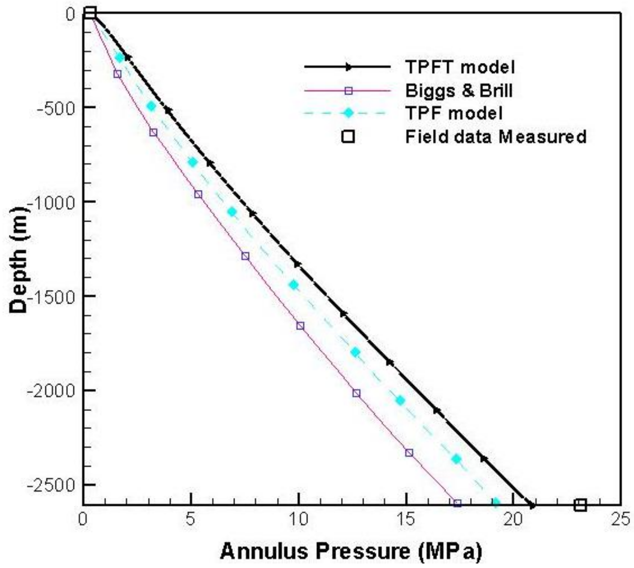

Figure 4. Comparison of pressure distribution obtained from different models

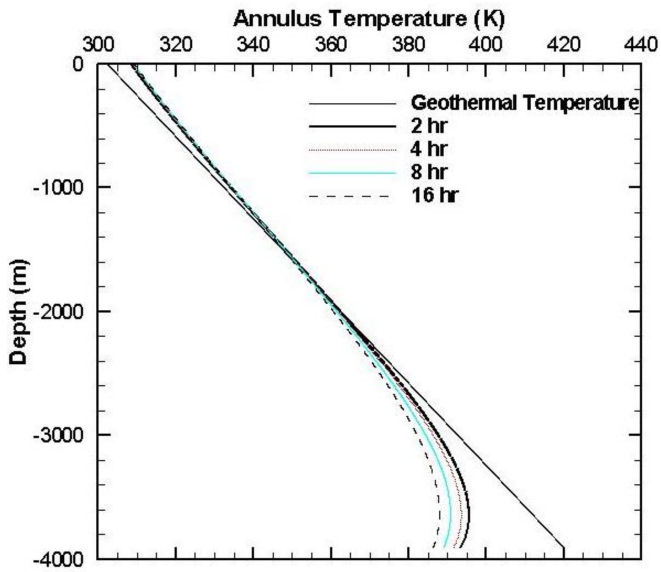

Figure 5. Effect of circulation time on Annulus temperature profile

Bearing in mind the geothermal gradient for a formation depends on its thermal conductivity and it varies with the type of formation, in this study effect of geothermal gradients variation on temperature profile in the well has been performed. Figure 6 shows three cases with geothermal gradients of 0.026, 0.03, and 0.036 k/m for Iride 1166 well. In this figure the dashed line in the legend represents the temperature of drilling fluid in the drill string and the solid line represents the temperature of the fluid in the annulus. In all of the simulations, the surface geothermal temperature is kept at 302.4K. The formation temperatures at the bottom of the hole at 3901m are 403.8k, 419.8k, and 442.8k, respectively. A higher geothermal gradient results in a higher formation temperature at a given depth. When there is a large difference between the formation temperature and drilling fluid temperature, it will cause a high heat flux between the drilling fluid and the surrounding formations. This results in an increased temperature of the drilling fluid as compared to the low geothermal gradient case. It is also evident from Fig.6 that a high geothermal gradient not only affects the temperature of mud in the annulus, which is in direct contact with the formations, but the temperature of mud in the drill pipe is also raised. When the mud comes up to the surface, the temperature of mud in the higher geothermal gradient case is much higher than the lower geothermal gradient case.

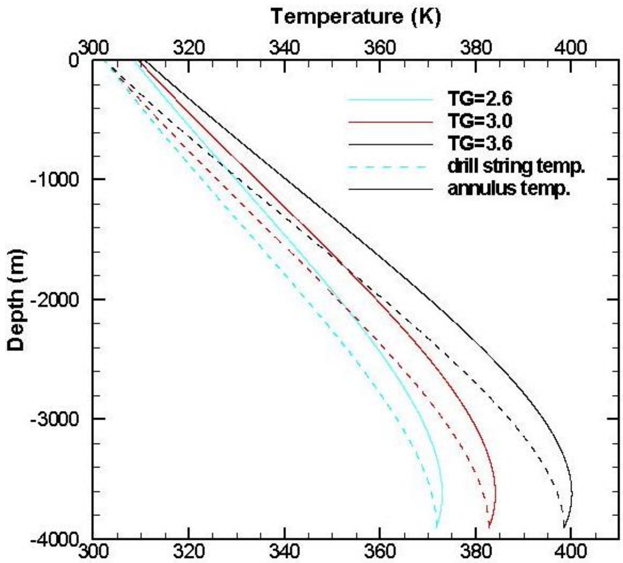

Figure 6. Effect of geothermal gradient on temperature profile in the well

Comparisons of the present results (gas-liquid two-phase flow with thermal consideration or TPFT model) with the gas-liquid two-phase flow with geothermal temperature distribution (TPF model) are shown in table 4. The simulation was performed assuming that the oil and natural gas flow rates that will enter into the wellbore during drilling. It is found that for oil and gas production during the under-balanced drilling operation and BHP prediction, TPFT model simulator predicts better than TPF model.

5. Conclusion

The developed gas-liquid two-phase flow with thermal consideration (TPFT model) simulator can be used as a swift tool to estimate the pressure and temperature distribution as well as better estimate bottom-hole pressure (BHP) that is important for the under-balanced drilling (UBD) operation. Effects of oil and gas production from the reservoir and energy sources on heat transfer of gas-liquid two-phase flow with the environment were considered in the model. Based on the results, major conclusions are as follows:

Results for Muspac 53 well show that, two-phase flow with thermal consideration (TPFT model) gives relatively better results compared to two-phase flow with geothermal temperature distribution (TPF model) for the pressure distribution along the annulus and BHP. for the BHP prediction the error of the TPFT model is approximately 5% less than the TPF model.

Also, Comparison of the accuracy of TPFT model and TPF model simulations with the field data from Iride 1166 well show that for the BHP prediction the average error of the TPFT model simulation is approximately 0.2 % less than the TPF model simulation and for the oil and gas production during UBD operation the relative deviation of the TPFT model simulation is approximately one percent less than the TPF model simulation.

Table 4. Comparison of TPFT model with TPF model and Field data

	Bottom-hole pressure (MPa)	Relative deviation (%)	Production (m^3/day)	Relative deviation (%)
Field data Measured [10]	20.7	-	474	-
TPF model [14]	20.645	0.266	489	3.17
TPFT model	20.688	0.058	486	2.53

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