Study on the wellbore temperature distribution characteristics during foam drilling

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Abstract. In view of the specific properties of foam drilling fluids, a wellbore temperature calculation model during foam drilling has been established in this study, considering the Joule-Thomson influence, heat generation by pressure drop of nozzle, frictional heating between drill bit and formation, and frictional heating during foam flow. In addition, the solution of this model is solved by coupling method. Through calculation with examples, the results show that at the shallow well section, the foam temperature in annulus is higher than the formation temperature, and at the deep well section, the foam temperature is lower than the formation temperature. With the increase of liquid injection rate and gas injection rate, the foam temperature in annulus at the downhole and in coiled tube decreases, and the foam temperature in annulus at the wellhead increases. The foam injection temperature has a significant influence on the foam temperature. Increasing the injection temperature can improve the foam stability at the downhole.

Keywords: foam drilling fluid; steady heat transfer; wellbore temperature; Joule-Thomson effect; frictional heating.
fraction) of the foam drilling fluid should be controlled within 55% to 96%. The gas phase concentration is relatively large, and the physical properties are sensitive to temperature. When the foam drilling fluid circulates in the wellbore, the heat exchange occurs between the foam in annulus and formation, and between the foam in annulus and the foam in drill pipe, and the mechanical energy and internal energy of the foam drilling fluid are also mutually converted, making a large deviation in the foam temperature and the formation temperature. If neglecting the temperature variation of foam drilling fluid during the drilling process, bigger errors will occur in the predicted key parameters such as downhole pressure, minimum sand carrying velocity, and minimum gas injection rate. In this study, a calculation model has been established for distribution of the wellbore temperature during foam drilling, considering the influence of the Joule-Thomson effect, frictional heating by bit and frictional heating during foam flow, and the factors affecting the distribution of the wellbore temperature have been analyzed.

1. Mathematical model

The circulation of foam drilling fluid in the wellbore is complicated. For convenience of the study, in this paper, we make the following assumptions. First, the foam drilling fluid is a single-phase fluid, which flows steadily in one dimension in the wellbore. Second, the gas-liquid two-phase in the foam drilling fluid is in a thermodynamic equilibrium state. At any position crossing the flow section, the physical properties of the foam are the same, and the velocity, pressure and temperature are also the same. Third, the heat transfer between drill pipe and annulus is steady, and the heat transfer between annulus and formation around the wellbore is unsteady.

(1) Continuity equation

When foam drilling fluid flows steadily in the wellbore, the mass flow rate is constant, so the continuity equation can be expressed as

\[
\frac{dw}{dz} = \frac{d(\rho v A)}{dz} = 0
\]

(1)

Where, \( w \) is the mass flow rate of foam drilling fluid flowing in annulus (or drill pipe), kg/s; \( \rho \) is the density of foam drilling fluid, kg/m\(^3\); \( v \) is the flow velocity of foam drilling fluid, m/s; and \( A \) is the cross-sectional area of annulus (or drill pipe), m\(^2\).

(2) Pressure drop model

By simplifying and deforming the steady flow momentum theorem along the flow direction, the pressure drop model of foam drilling fluid flowing in drill pipe and annulus can be obtained as follows [8]:

\[
\left( \frac{dP}{dL} \right)_t = \left( \frac{dP}{dL} \right)_h + \left( \frac{dP}{dL} \right)_f + \left( \frac{dP}{dL} \right)_a
\]

(2)

Where, \( \left( \frac{dP}{dL} \right)_t \) is the total pressure gradient, Pa/m; \( \left( \frac{dP}{dL} \right)_h \) is the hydraulic pressure gradient, Pa/m; \( \left( \frac{dP}{dL} \right)_f \) is the friction pressure gradient, Pa/m; \( \left( \frac{dP}{dL} \right)_a \) is the acceleration pressure gradient, Pa/m.

The pressure drop of nozzle is calculated by the formula given by Okpobiri [9].

(3) Heat transfer model

The energy conservation equation of steady heat transfer can be expressed as: the sum of the energy at the inlet of the control unit and the inflow energy is equal to the sum of the energy at the outlet of the control unit and the outflow energy. Combined with the Hasan’s [10] method for establishing a wellbore circulation heat transfer model, the heat transfer model of the foam drilling fluid along the flow direction in the wellbore can be obtained as

\[
c_w \frac{dT_a}{dz} + \frac{c_l}{A} (T_a - T_e) + \frac{c_l}{B} (T_a - T_d) = C_T c_{pa} \frac{dP}{dz} + g \cos \theta \frac{vdv}{dz} + q_{in,s}
\]

(3)
\[ c_{fa} \frac{dT_a}{dz} + \frac{c_{fa}}{B} (T_a - T_d) = C_J \frac{dp}{dz} - g \cos \theta - \frac{vdv}{dz} + q_{dp,s} \]  

(4)

Where, \( T_{fa} \), \( T_a \) and \( T_d \) are the formation temperature, the foam temperature in annulus and foam temperature in drill pipe, respectively, \( K \); \( C_J \) is the Joule-Thomson coefficient of the foam, \( K/Pa \); \( c_{fa} \) and \( c_{fa} \) are the heat capacity of the foam in annulus and drill pipe at constant pressure, respectively, \( J/(kg \cdot K) \); \( A \) and \( B \) are the relaxation distance, \( m \); \( \theta \) is the deviation angle, \(^\circ\); \( g \) is the gravitational acceleration, \( m/s^2 \); \( q_{an,s} \) and \( q_{dp,s} \) are the heat sources, \( J/kg \).

The heat source of \( q_{an,s} \) in equation (3) mainly includes frictional heating between drill bit and formation \(^{[11]}\), \(^{[12]}\), rotary torque \(^{[13]}\), frictional heating by foam flow \(^{[14]}\) and carrying energy of formation fluid intrusion, while the heat source of \( q_{dp,s} \) in equation (4) mainly includes frictional heating by foam flow \(^{[14]}\).

(4) State equation and boundary conditions

State equation: the gas phase in the foam drilling fluid adopts the non-ideal gas state equation to express the relationship between pressure, temperature and density. The density of the liquid phase in the foam drilling fluid can be regarded as a constant, i.e. \( \rho_l \equiv constant \).

Boundary conditions: during foam drilling, the foam injection temperature at the wellhead and the pressure at the outlet of annulus are known and can be used as boundary conditions, that is

\[ T_d \big|_{z=0} = T_{inj}, \quad p_a \big|_{z=0} = p_b \]  

(5)

Where, \( T_{inj} \) is the injection temperature of foam drilling fluid, \( K \); \( p_a \) is the annulus pressure, \( Pa \); \( p_b \) is the wellhead back pressure, \( Pa \).

The above-mentioned continuity equation, pressure drop model, heat transfer model, state equation and boundary conditions constitute a mathematical model of wellbore temperature during foam drilling.

2. Solution of the mathematical model

2.1. Calculation of relevant parameters

(1) Foam quality, density and velocity. If the pressure and temperature at a specific well depth are known, the foam quality, density and velocity can be calculated according to the method given in literature \(^{[11]}\).

(2) Friction coefficient. Studies have shown that foam drilling fluid is a typical non-Newtonian fluid. The power law mode is used to describe its rheological property \(^{[16]}\). The Moody formula is used to calculate the friction coefficient of laminar flow in drill pipe \(^{[16]}\). The formula proposed by Frederickson & Bird \(^{[17]}\) is used to calculate the Fanning friction coefficient of laminar flow in annulus. The Dodge & Motzner formula \(^{[16]}\) is used to calculate the Fanning friction coefficient in turbulent flow.

(3) Thermal physical parameters. The formula given in literature \(^{[18]}\) is used to calculate the foam heat capacity at constant pressure and the Joule-Thomson coefficient. The method given in literature \(^{[15]}\) is used to calculate the thermal conductivity. The formula given in literature \(^{[20]}\) and \(^{[21]}\) is used to calculate the convective heat transfer coefficient and total heat transfer coefficient of foam flowing in annulus and drill pipe.

2.2. Solution method

It can be seen from the equations (3) and (4) that change in pressure and velocity will cause change in foam temperature. Conversely, change in temperature will also cause change in gas phase density, which will cause change in foam density and flow velocity. Therefore, the heat transfer equation and momentum equation are interacted and need to be solved by coupling methods. The iterative method and the fourth-order Runge-Kutta method are used to calculate the foam pressure and temperature. The rest of the relevant parameters are calculated by the methods given in the above-mentioned literatures.
3. Cases analysis
The basic parameters selected in the calculation are as follows: the borehole diameter is 0.22 m, the inner diameter of drill pipe is 0.055 m, the outer diameter of drill pipe is 0.073 m, the inner diameter of casing is 0.16 m, outer diameter of casing is 0.18 m, the foam temperature at the inlet of drill pipe is 20℃, the ground temperature is 20℃, the geothermal gradient is 0.03 K/m, the formation thermal conductivity is 2.0 W/(m·K), the formation diffusion coefficient is 0.00265, the cycle time is 2 m²/h. The liquid injection rate (QL) and the gas injection rate (QG) under standard conditions are variable.

3.1. Influence of liquid injection displacement

Figure 1 shows the foam temperature profiles in annulus and drill pipes under different liquid injection rates. It can be seen from Figure 1 that the liquid injection rate has a significant influence on the foam temperature profile. The foam temperature in drill pipe is always lower than the foam temperature in annulus and the formation temperature. When the well depth is less than 1450 m, the foam temperature in annulus is higher than the formation temperature. When the well depth is greater than 1450 m, the foam temperature in annulus is higher than the formation temperature. As the well depth increases or decreases, the deviation between the foam temperature and the formation temperature increases, and the maximum deviation is at the wellhead or downhole. With the increase of the liquid injection rate, the foam temperature in annulus and drill pipe at the downhole decreases, and the foam temperature in annulus at the wellhead increases. This is due to the foam velocity and heat capacity at constant pressure increase with the increase of the liquid injection rate, and resulting in the decrease of the heat absorption or release rate by the foam per unit mass flow rate in unit time.

3.2. Influence of gas injection displacement

Figure 2 shows the foam temperature profiles in annulus and coiled tube under different gas injection rates. It can be seen from Figure 2 that the gas injection rate has a significant influence on the foam temperature profile. The foam temperature in drill pipe is always lower than the foam temperature in annulus and the formation temperature. At a specific well depth, the foam temperature in annulus is equal to the formation temperature. When the well depth is less than the specific well depth, the foam temperature in annulus is lower than the formation temperature. When the well depth is greater than the specific well depth, the foam temperature in annulus is higher than the formation temperature. With the increase of the gas injection rate, the foam temperature in annulus and coiled tube at the downhole decreases, the foam temperature in annulus at the wellhead increases, and the well depth corresponding
to the foam temperature in annulus being equal to the formation temperature decreases. This is due to the heat capacity of the foam at constant pressure decreases with the increase of the gas injection rate, but the flow velocity increases, and resulting in the decrease of the heat absorption or release rate by the foam per unit mass flow rate in unit time.

3.3. Influence of wellhead back pressure

Figure 3 shows the foam temperature profiles in annulus and drill pipe under different wellhead back pressures. It can be seen from Figure 3 that with the change of the wellhead back pressure, the foam temperature profile does not change significantly. With the increase of the wellhead back pressure, the foam temperature in annulus and coiled tube at the downhole increases, and the foam temperature in annulus at the wellhead decreases. This is due to the foam velocity decreases and the heat absorption or release rate by the foam per unit mass flow rate increases with the increase of wellhead back pressure. In addition, due to the increase of wellhead back pressure, the foam quality and velocity in annulus and drill pipe decrease, the heat capacity at constant pressure increases, and the convective heat transfer rate of the foam in formation and annulus, and the foam in annulus and coiled tube decreases. Therefore, the wellhead back pressure has an influence on the foam temperature profile, but the influence is not obvious.

3.4. Influence of injection temperature

Figure 4 shows the foam temperature profiles in annulus and drill pipe at different foam injection temperatures. It can be seen from Figure 4 that the foam injection temperature has a significant influence on the foam temperature profile. With the increase of the injection temperature, the foam temperature
in annulus and drill pipe both increases. Increasing the foam injection temperature can increase the foam temperature at the downhole and improve the stability of the foam at the downhole, but at the same time, the foam temperature at the wellhead will increase, reducing the stability of the foam at the wellhead. Therefore, if conditions permit and do not affect the flow characteristics of the foam, increasing the foam injection temperature can save the amount of gas injection, thus saving drilling costs.

Fig. 4 The influence of foam injection temperature on foam temperature profiles

4. Conclusion
(1) The foam temperature in annulus is always higher than the foam temperature in coiled tube. In the shallow well section, the foam temperature in annulus is higher than the formation temperature. In the deep well section, the foam temperature is lower than the formation temperature.
(2) With the increase of liquid injection rate and gas injection rate, the heat absorption or release rate by the foam per unit mass flow rate in unit time decreases, the foam temperature in annulus and drill pipe at the downhole decreases, and the foam temperature in annulus at the wellhead increases. With the increase in the wellhead back pressure, the foam velocity will decrease, and the heat capacity at constant pressure will increase, and the convective heat transfer rate of the foam will decrease for foam in formation and annulus and the foam in annulus and coiled tube, the heat absorption or release rate by the foam per unit mass flow rate in unit time will increase, and the foam temperature in annulus and drill pipe at the downhole will increase. Although the wellhead back pressure has an influence on the foam temperature profile, the influence is not obvious. The foam injection temperature has a significant influence on the foam temperature. Increasing the injection temperature can improve the foam stability at the downhole.

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