Research on Wellbore Pressure Distribution Model for Injection Wells During Foam Flooding

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Abstract. Foam flooding technology is an effective measure of EOR in oilfield development. In order to properly design the injection project, it is necessary to study the pressure distribution state of foam along the wellbore in injection wells. Based on the existing flow law research of foam fluids in the wellbore, this paper introduced temperature field calculation of heat transfer between the wellbore and foam in the theoretical study. Considering both rheological properties and PVT characteristics of foam fluids, the wellbore pressure distribution model was established. The iterative calculation method was used to calculate the whole wellbore pressure distribution of foam injection wells. Based on the new model, the effects of parameters such as foam flow rate of liquid and gas, injection pressure, injection temperature and tubing diameter on the wellbore pressure distribution of foam were analyzed. Meanwhile, the wellbore temperature and pressure distribution profiles of one case well were calculated, which meet the requirements of engineering application. In this paper, the whole wellbore pressure distribution model which introduced foam characteristics and temperature field calculation of heat transfer was established, and relevant influencing factors were analyzed. It has the important guiding significance for establishment of a reasonable production system for foam flooding oilfield development.

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1 Introduction

Foam is a multiphase disperse system in which gas is dispersed in liquid. In a foam fluid, the liquid is continuous phase and the gas is discontinuous phase. Foam belongs to a typical kind of non-Newtonian fluids, which has the advantages of low friction, low density, low filter loss, strong backflow capacity, strong ability to carry solid particles, and little damage to the reservoir. It is widely used in various engineering technologies such as drilling,completion, stimulation improvement, workover and EOR in the development of the oil and gas fields, which has achieved good application results [1, 2]. Foam flooding is a displacement method in which different kinds of gases are mixed with foam agents as displacement mediums [3]. As fluidity-control fluid in the displacement process, foam can improve the fluidity ratio, prevent water channeling or fingering during water flooding, expand the flooding area of water and gas, and enhance oil and gas recovery. Therefore, foam flooding technology has a great development prospect in oilfield development.

The application of foam fluids in the petroleum industry began in the 1950s. Scholars have done many experimental and theoretical studies on the rheological properties, stability, and hydraulic calculation of foam. Since 1960, Mitchell [4], Blauer [5], Princen [6], Kraynik [7] and others have successively studied the change law of foam structure, viscosity and shear stress with the change of foam quality. In addition, scholars such as Krug [8], Lord [9] and Sanghani and Ikoku [10] also made important contributions to the hydraulic calculation methods of foam fluids. Among them, Lord's method has been widely used in petroleum engineering, but it requires the determination of high-precision average friction coefficient.

The calculation of the wellbore pressure distribution of foam is the basis for optimal design of injection project during foam flooding, and its importance is obvious. The author investigated the research progress on calculation methods of the foam-filled wellbore pressure distribution and found that all research objects are stable foam with foam quality concentrated between 55 and 95%. Through analysis and summary, it is found that the current research has following three limitations: a. Most temperature field calculation models are too simple. Only the geothermal gradient is introduced into the calculation model, and the heat transfer law between the wellbore and foam is not considered. Since gas characteristics are extremely sensitive to temperature changes, there is a large calculation error existing. b. Due to the unclear rheological properties of foam fluids and the insufficient consideration of its PVT characteristics, various physical parameters during the calculation process are simplified, which ultimately leads to a large deviation between the calculation results and the actual field data. c. The calculation processes of most models are extremely complicated, which are not satisfied the requirements of engineering application and difficult to promote in the field. In the study of this paper, the author fully considered rheological properties and PVT characteristics of foam fluids, introduced the heat transfer law calculation between the wellbore and foam, perfected temperature field calculation, and established a new model of wellbore pressure distribution. The iterative calculation method was used to calculate the pressure distribution of the whole injection wellbore during foam flooding.

2 Wellbore Pressure Distribution Model

It is assumed that the research object is stable foam of one-dimensional single-phase flow ($0.55 \leq \Gamma \leq 0.95$), the flow process ignores the slip-off motion between gas and liquid, and the physical parameters of foam are the same on any flow cross section.

According to the momentum conservation principle, the following general wellbore pressure gradient equation can be established:

$$\left(\frac{dP}{dH}\right)_{total} = \left(\frac{dP}{dH}\right)_{gravity} + \left(\frac{dP}{dH}\right)_{friction} + \left(\frac{dP}{dH}\right)_{acceleration} \tag{1}$$

where $\left(\frac{dP}{dH}\right)_{total}$, $\left(\frac{dP}{dH}\right)_{gravity}$, $\left(\frac{dP}{dH}\right)_{friction}$ and $\left(\frac{dP}{dH}\right)_{acceleration}$ are total pressure gradient (MPa/m), gravity pressure gradient (MPa/m), friction pressure gradient (MPa/m) and acceleration pressure gradient (MPa/m) respectively.

For one-dimensional single-phase stable foam flow, the effect of the acceleration term can be ignored, there is:

$$\left(\frac{dP}{dH}\right)_{total} = \left(\frac{dP}{dH}\right)_{gravity} + \left(\frac{dP}{dH}\right)_{friction}. \tag{2}$$

If the direction of injection (from top to bottom) is positive, the expression is as follows:

$$\frac{dP}{dH} = \rho_F g \sin\theta - \lambda \frac{\rho_F}{D} \frac{v_F^2}{2} \tag{3}$$

where P is pressure (MPa), H is wellbore depth (m), ρ_F is foam density $(\mathrm{kg/m^3})$, g is gravitational acceleration $(\mathrm{m/s^2})$, θ is angle between the wellbore and the horizontal plane (°), λ is friction coefficient, D is tubing inner diameter (m), v_F is foam flow velocity (m/s).

Equation (3) is the mathematical model for calculating the wellbore pressure distribution of foam. Obviously, the key is to get the value of ρ_F, λ and v_F as precisely as possible. Since the compressibility of gas phase in foam is extremely strong, the three parameters can be affected by the changes of pressure and temperature along the wellbore to varying degrees. In other words, the parameters of foam are constantly changing, so how to select and evaluate the values of these three parameters becomes the key to accurately calculate the pressure distribution of the whole wellbore.

3 Calculation of Key Foam Parameters

3.1 Foam Density

For the convenience of calculation, it is assumed that the liquid phase in foam is incompressible, only the gas phase can be compressed, and the mass ratio of gas and liquid in foam is constant. According to the real gas state equation:

$$pV_g = \frac{m_g}{M_g} ZRT. \tag{4}$$

The following expressions can be given:

$$\rho_g = \rho_{gst} \left(\frac{Z_{st}}{Z} \right) \left(\frac{p}{p_{st}} \right) \left(\frac{T_{st}}{T} \right) \tag{5}$$

$$V_g = V_{gst} \left(\frac{Z}{Z_{st}} \right) \left(\frac{p_{st}}{p} \right) \left(\frac{T}{T_{st}} \right) \tag{6}$$

where p and p_{st} are gas pressure (MPa) and gas pressure under standard conditions (0.101 MPa), V_g and V_{gst} are gas volume (m^3) and gas volume under standard conditions (m^3), m_g is gas quality (kg), M_g is molar quality of gas (kg/kmol), Z is compressibility factor of gas, R is gas constant (8.31×10^{-3} $\mathrm{MPa} \cdot \mathrm{m}^3 \cdot \mathrm{kmol}^{-1} \cdot \mathrm{K}^{-1}$), T and T_{st} are gas temperature (K) and gas temperature under standard conditions (273.15 K), ρ_g and ρ_{gst} are gas density ($\mathrm{kg/m}^3$) and gas density under standard conditions ($\mathrm{kg/m}^3$).

The general expression for foam density is as follows:

$$\rho_F = \frac{m_l + m_g}{V_l + V_g} = \frac{\rho_l \cdot V_l + \rho_g \cdot V_g}{V_l + V_g} \tag{7}$$

where m_l, V_l and ρ_l are foam liquid phase quality (kg), foam liquid phase volume (m^3) and foam liquid phase density ($\mathrm{kg/m}^3$) respectively.

Substitute Eqs. (5) and (6) into Eq. (7) to obtain the expression of foam density:

$$\rho_F = \frac{\rho_l \cdot V_l + \rho_{gst} \cdot V_{gst}}{V_l + V_{gst} \left(\frac{Z}{Z_{st}} \right) \left(\frac{p_{st}}{p} \right) \left(\frac{T}{T_{st}} \right)}. \tag{8}$$

Set the gas-liquid ratio of foam under standard conditions: $R_{GLst} = \frac{V_{gst}}{V_l}$, then Eq. (8) can be changed into following expression:

$$\rho_F = \frac{\rho_l + \rho_{gst} \cdot R_{GLst}}{1 + R_{GLst}\left(\frac{Z}{Z_{st}}\right)\left(\frac{p_{st}}{p}\right)\left(\frac{T}{T_{st}}\right)}. \tag{9}$$

Foam quality is defined as the gas volume content in the foam under certain pressure and temperature conditions, that is:

$$\Gamma = \frac{V_g}{V_g + V_l} = \frac{1}{1 + \frac{1}{R_{GL}}}. \tag{10}$$

Set Γ_{st} as foam quality under the standard conditions, then:

$$\Gamma_{st} = \frac{V_{gst}}{V_{gst} + V_l} = \frac{1}{1 + \frac{1}{R_{GLst}}}. \tag{11}$$

When Eq. (6) and Eq. (11) are substituted into Eq. (10), there is:

$$\Gamma = \frac{\Gamma_{st}}{\Gamma_{st} + (1 - \Gamma_{st})\left(\frac{Z_{st}}{Z}\right)\left(\frac{p}{p_{st}}\right)\left(\frac{T_{st}}{T}\right)}. \tag{12}$$

Substitute Eq. (11) into Eq. (9), and the following expression of foam density can be obtained:

$$\rho_F = \frac{\rho_l(1 - \Gamma_{st}) + \rho_{gst} \cdot \Gamma_{st}}{1 - \Gamma_{st} + \Gamma_{st}\left(\frac{Z}{Z_{st}}\right)\left(\frac{p_{st}}{p}\right)\left(\frac{T}{T_{st}}\right)}. \tag{13}$$

Gas compressibility factor Z is a function of pressure and temperature, and the remaining parameters are known quantities. Therefore, given a set of pressure and temperature data, the foam density at this state can be calculated according to the above equation.

3.2 Friction Coefficient

Foam is a typical kind of non-Newtonian fluids, and the rheological model must be considered in hydraulic calculation. It is found that the most commonly used rheological models are Bingham model, Power-law model and Herschel-Buckley model. Most scholars regard foam as a compressible non-Newtonian power law fluid. The author also considers that the rheological model of foam is more consistent with power law model.

In 1981, Sanghani and Ikoku simulated and tested the rheological properties of foam in the wellbore and annulus. According to the regression analysis of experimental data, the relationship between foam quality Γ and generalized fluid consistency coefficient K' and fluidity index n was obtained: (Table 1).

Table 1 Relationship between Γ, K' and n

Γ	$K'(\mathrm{Pa \cdot s^n})$	n
$96\% < \Gamma \leq 98\%$	4.529	0.326
$92\% < \Gamma \leq 96\%$	5.880	0.290
$75\% < \Gamma \leq 92\%$	$34.330\Gamma - 20.732$	$0.7734 - 0.643\Gamma$
$55\% < \Gamma \leq 75\%$	$2.538 + 1.302\Gamma$	0.295

The relationship between generalized fluid consistency coefficient K' and consistency coefficient K is:

$$K' = K\left(\frac{3n+1}{4n}\right)^n. \tag{14}$$

For power-law fluids, generalized Reynolds number Re'_{PL} is introduced to determine the flow state of foam in the wellbore:

$$Re'_{PL} = \frac{8^{1-n}\rho_F D^n v_F^{2-n}}{K\left(\frac{3n+1}{4n}\right)^n}. \tag{15}$$

For power-law fluid flowing in a circular tube, the theory of Hanks [11] is used to determine the generalized critical Reynolds number Re'_{PLc}:

$$Re'_{PLc} = 6464\frac{n(n+2)^{\frac{n+2}{n+1}}}{(3n+1)^2}. \tag{16}$$

If $Re'_{PL} \leq Re'_{PLc}$, the flow state is laminar, or if $Re'_{PL} > Re'_{PLc}$, the flow state is turbulent.

If the foam flow is laminar, friction coefficient λ can be calculated according to the following formula:

$$\lambda = \frac{64}{Re'_{PL}}. \tag{17}$$

If the foam flow state is turbulent, the semi-empirical formula of Dodge and Metzner [12] can be used to calculate friction coefficient λ:

$$\frac{1}{\sqrt{f}} = \frac{4.0}{(n')^{0.75}} \lg\left[Re'_{PL} \cdot f^{\left(1-\frac{n'}{2}\right)}\right] - \frac{0.4}{(n')^{1.2}}. \tag{18}$$

Here, f is Fanning friction coefficient ($\lambda = 4f$), and n' is flow characteristic index, for power-law fluids, fluidity index $n = n'$.

The above expression is an implicit equation. For simplifying, Dodge and Meltzer concluded the Blasius-type empirical formula of the turbulent friction coefficient of power-law fluids from the relationship graph based on the experimental data:

$$f = \frac{a}{\left(\mathrm{Re}'_{PL}\right)^b}. \tag{19}$$

In the expression, a and b both are functions of the fluidity index n, The relationship between them is shown in the following (Table 2):

Table 2 Coefficient values in Blasius formula

n	a	b
0.2	0.2584	0.349
0.3	0.2470	0.325
0.4	0.2848	0.307
0.6	0.2960	0.281
0.8	0.3044	0.263
1.0	0.3116	0.250
1.4	0.3212	0.231
2.0	0.3304	0.213

In addition, the simplified modified Blasius formula can be also used to calculate:

$$f = \frac{a}{4\left(\mathrm{Re}'_{PL}\right)^b}. \tag{20}$$

Here, the value of a and b are calculated according to the following expressions:

$$a = 0.314n^{0.105} \tag{21}$$

$$b = 0.2495n^{-0.217}. \tag{22}$$

3.3 Foam Flow Velocity

During steady injection process of foam, the gas phase is compressed to change the flow rate of foam due to changes in temperature and pressure, which in turn causes changes in the pressure distribution along the wellbore. Thus, a reasonable calculation of the distribution of foam flow rate along the wellbore is a prerequisite for calculating pressure distribution accurately.

The flow velocity of stabilized foam in the wellbore is:

$$v_F = \frac{Q_g + Q_l}{\frac{\pi}{4} D^2} \tag{23}$$

where Q_g and Q_l are volume flow rate of gas phase and liquid phase in foam respectively (m^3/s).

For the gas phase portion in foam, the following expression can be obtained from Eq. (6):

$$Q_g = Q_{gst}\left(\frac{Z}{Z_{st}}\right)\left(\frac{p_{st}}{p}\right)\left(\frac{T}{T_{st}}\right) \tag{24}$$

where Q_{gst} is volume flow rate of gas phase in foam under standard conditions (m^3/s).

Substitute Eq. (24) into Eq. (23), then:

$$v_F = \frac{4\left[Q_{gst}\left(\frac{Z}{Z_{st}}\right)\left(\frac{p_{st}}{p}\right)\left(\frac{T}{T_{st}}\right) + Q_l\right]}{\pi D^2}. \tag{25}$$

According to Eq. (25), the foam flow velocity under any temperature and pressure conditions along the wellbore can be obtained.

4 Temperature Field Model

In fact, the heat transfer law of wellbore temperature field during foam injection process is complicated. The gas phase in foam is extremely sensitive to temperature changes. It is obvious that only the change of formation temperature cannot accurately reflect the heat transfer law in wellbore. Therefore, calculation of the wellbore temperature field should not only conform to actual heat transfer law, but also the influence of some secondary factors should be neglected to simplify calculation process. For the convenience of research, the author makes the following assumptions: a. The gas and liquid phases are in a thermodynamic equilibrium state. b. The heat transfer in the wellbore is steady-state, while the heat transfer in the surrounding strata is unsteady. c. The heat transfer between wellbore and formation is radial, without considering the heat transfer along the shaft direction, and ignoring the frictional heat generated during foam injection. d. The change of thermodynamic parameters along well-depth direction with the temperature is not considered.

In the injected wellbore, heat will be transferred in the following links due to temperature difference: Injected foam—tubing wall—casing annular space—casing wall—cement ring—formation, as shown below (Fig. 1).

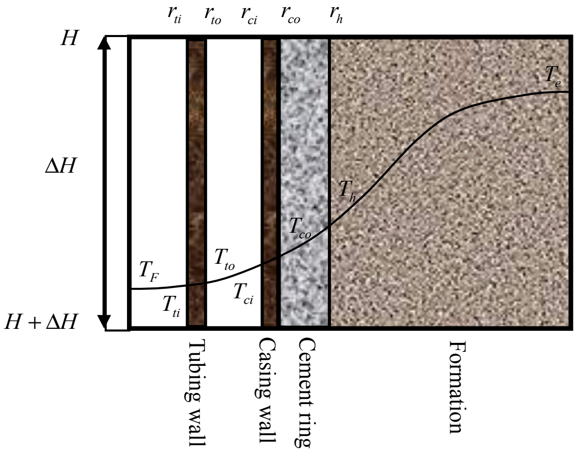

Fig. 1 Structure and temperature conduction diagram of injection well

In the process of injecting, heat flow Q_w exchanged radially between tubing and the wellbore near-well formation (to the interface between cement ring and formation), that is, thermal variation of the wellbore. The radial heat transfer process of any micro-element segment dH satisfies the steady-state heat transfer equation, then:

$$dQ_w = 2\pi r_{to} U_t (T_h - T_F) \cdot dH \tag{26}$$

where r_{to}, U_t, T_F and T_h are outer radius of tubing (m), total heat transfer coefficient based on the outer surface of tubing ($\mathrm{kJ \cdot m^{-2} \cdot h^{-1} \cdot {}^{o}C^{-1}}$), foam temperature (°C)and temperature at the interface between cement ring and formation (°C).

In fact, total heat transfer coefficient U_t is a function of well depth and time. It is usually assumed that the thermodynamic parameters of the wellbore do not change with temperature, and the parameters under average temperature are used for approximate calculation.

The heat change of foam Q_F in this micro-segment through the heat transfer process is:

$$dQ_F = W_{inj} C_p \cdot dT_F \tag{27}$$

where W_{inj} and C_p are mass flow rate of injection foam $(\mathrm{kg/h})$ and constant pressure specific volume of injection foam $(\mathrm{kJ \cdot kg^{-1} \cdot {}^{o}C^{-1}})$.

The differential equation of formation radial unsteady heat transfer [13] is:

$$\frac{\partial^2 T_e}{\partial r^2} + \frac{1}{r}\frac{\partial T_e}{\partial r} = \frac{1}{\alpha}\frac{\partial T_e}{\partial t} \tag{28}$$

where T_e, α and t are formation temperature (°C), thermal diffusion coefficient of formation $(\mathrm{m^2/s})$ and injection time (h).

In order to simplify the process of calculation, the semi-analytical method of Ramey [14] was adopted. By introducing non-dimensional transient heat transfer function $f(t_D)$, radial heat flow of interface between cement ring and formation Q_f is:

$$dQ_f = \frac{2\pi\lambda_e(T_e - T_h)\cdot dH}{f(t_D)}. \tag{29}$$

In the expression above, λ_e is thermal conductivity of formation $(\mathrm{kJ\cdot m^{-1}\cdot h^{-1}\cdot {}^{o}C^{-1}})$.

$f(t_D)$ can be calculated according to Hasan [15] formula:

$$t_D = \frac{\alpha t}{r_h^2} \tag{30}$$

$$f(t_D) = \begin{cases} 1.1281\sqrt{t_D}(1 - 0.3\sqrt{t_D}), (t_D \le 1.5) \\ (0.4063 + 0.5\ln t_D)\left(1 + \frac{0.6}{t_D}\right), (t_D > 1.5) \end{cases} \tag{31}$$

where t_D and r_h are dimensionless time and well-hole radius (m).

When injection time is long enough, according to the study by Sagar [16], $f(t_D)$ can be directly calculated by the following formula:

$$f(t_D) = f_{t_D} = -10.70866 r_h + 3.53 \tag{32}$$

According to the principle of energy conservation, there is:

$$Q_F = Q_w = Q_f. \tag{33}$$

Set ground temperature as T_G and ground temperature gradient as G_T, then:

$$T_e = T_G + G_T H \sin\theta. \tag{34}$$

In combination (26), (27), (29), (33) and (34), the following expressions can be obtained:

$$\frac{dT_F}{dH} = K(T_G + G_T H \sin\theta - T_F) \tag{35}$$

$$K = \frac{2\pi r_{to} U_t \lambda_e}{W_{inj} C_p[\lambda_e + r_{to} U_t f(t_D)]}. \tag{36}$$

According to the above expressions, it is clear to find that temperature gradient is mainly affected by three factors: fluid temperature, ground temperature and well depth. The coefficient K takes effects of fluid properties, wellbore structures, formation properties and injection parameters into account.

5 Case Study

According to the new model, corresponding calculation program was compiled. The calculation model of foam temperature was solved by classical fourth-order Runge-Kutta method, and the wellbore pressure distribution of foam was calculated by iterative method.

The basic parameters of one injection well W in a nitrogen foam flooding block was shown in the table below (Table 3).

Table 3 Basic parameters of injection well W

Project	Unit	Value
Well-type	/	Vertical well
Depth	m	2850
Well-hole diameter	m	0.24
Tubing inner diameter	m	0.0620
Casing outer diameter	m	0.1397
Surface temperature	°C	20
Geothermal gradient	°C/m	0.03
Injection temperature	°C	20
Liquid density of foam	kg/m^3	1100
Liquid flow rate of foam	m^3/h	8.34
Gas flow rate of foam	Nm^3/h	420
Injection pressure	MPa	2.5

5.1 Calculation of Foam Temperature Along the Wellbore

Assuming injection time was long enough, Sagar's correlation was used to calculate non-dimensional transient heat transfer function. Substitute into parameters related the wellbore and heat transfer process, and temperature distribution of foam along the wellbore was obtained as shown in Fig. 2.

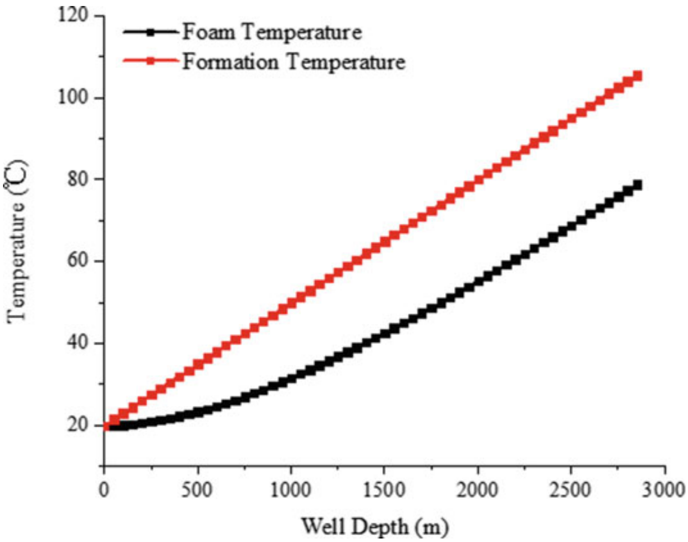

Fig. 2 Temperature distribution of foam along the wellbore

5.2 Calculation of Pressure Distribution Along the Wellbore

The pressure distribution of foam along the wellbore was calculated, as shown in Fig. 3.

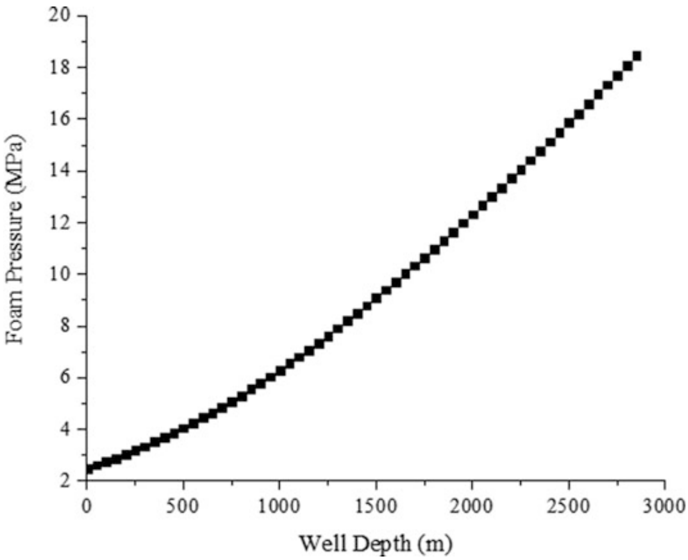

Fig. 3 Pressure distribution of foam along the wellbore

5.3 Comparison of Calculation Results

In order to verify the accuracy of the calculation results, commercial software WELLFLO was used to calculate under the same injection conditions. The following figure shows the pressure distribution curves obtained by these two models respectively (Fig. 4).

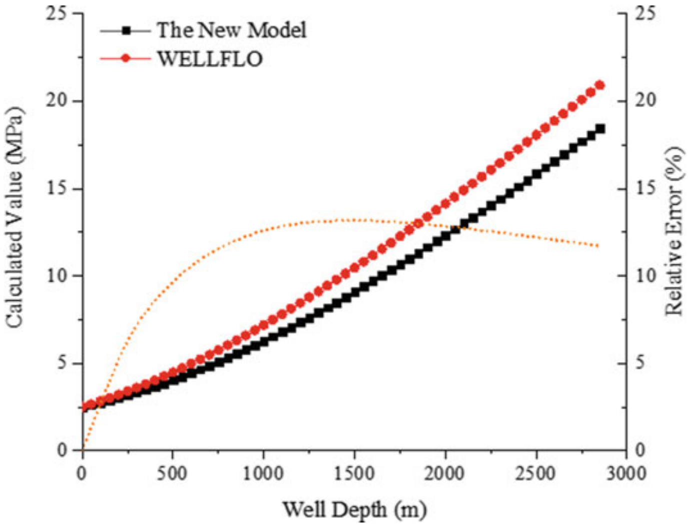

Fig. 4 Pressure distribution and relative error calculated by two models

As can be seen from the above figure, the results calculated by new model is closed to the results from WELLFLO, and the average relative error is 11.1%, which can meet the requirements of engineering calculation.

Because a simple linear geothermal gradient is used to calculate the temperature distribution of foam in WELLFLO, which makes the calculated value of foam temperature is larger than the actual situation, the results of wellbore pressure distribution of foam is also larger. Apparently, the analysis is consistent with the calculation results obtained in this paper.

6 Sensitivity Study

In fact, it is difficult to accurately calculate the wellbore pressure distribution of foam injection wells because the calculated parameters and conditions are numerous and the mechanism of flow changes is extremely complicated. Factors changed in the external environment such as formation temperature, formation pressure, well structure and physical properties of foam itself can affect the calculation of pressure distribution to varying degrees. Based on the established model and the calculated parameters of example application, four sensitivity factors including injection pressure, injection temperature, liquid flow rate & gas flow rate and tubing diameter were selected to analysis in this paper.

6.1 Injection Pressure

In this paper, six groups of different wellhead injection pressures of 1.5, 2.0, 2.5, 3.0, 3.5 and 4.0 MPa were selected to obtain the calculation results of wellbore pressure distribution of foam as shown in Fig. 5.

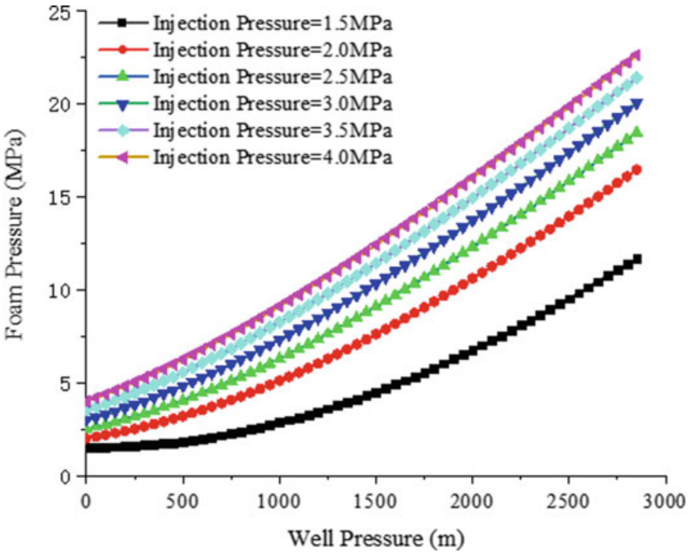

Fig. 5 Wellbore pressure distribution of foam under different injection pressures

As can be seen from the above figure, the total pressure difference of foam in the wellbore increases with the increase of injection pressure. When injection pressure is 1.5 MPa, the bottom hole pressure is 11.70 MPa, and the total pressure difference is 9.20 MPa. When injection pressure is increased to 4.0 MPa, the bottom hole pressure is 22.64 MPa and the total differential pressure is 20.14 MPa. Thus, the injection pressure increased by 2.5 MPa and the total differential pressure increased by 10.94 MPa. The reason for this phenomenon is that with the increasing of wellhead pressure, the gas volume in foam is compressed more and more, which leads to the increasing of total pressure difference. It can be inferred that in order to achieve a better injection effect, injection pressure should be increased as much as possible under the same conditions.

6.2 Injection Temperature

In this paper, five different foam injection temperatures of −10, 0, 10, 20 and 30 °C were selected. The wellbore pressure distribution of foam was calculated under the same conditions, and the calculation results as shown in the following figure were obtained (Fig. 6).

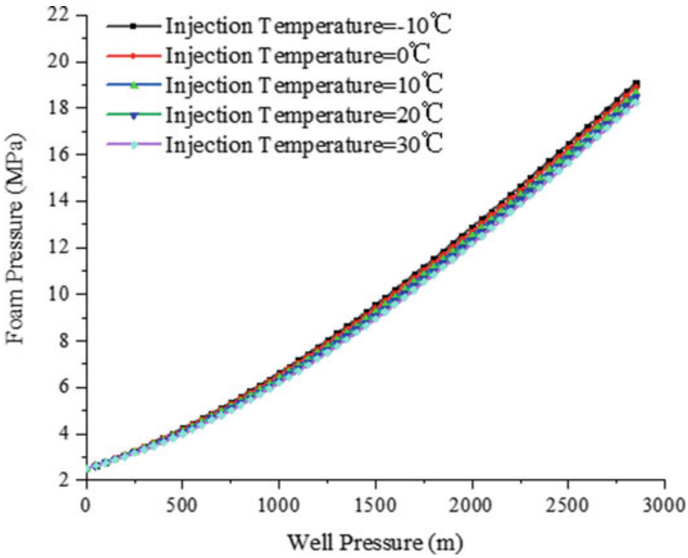

Fig. 6 Wellbore pressure distribution of foam under different injection temperatures

As can be seen from the above figure, the bottom hole pressure decreases with the increase of foam injection temperature. When the injection temperature is −10 °C, the bottom hole pressure is 19.10 MPa. When the injection temperature is 30 °C, the bottom hole pressure is 18.26 MPa. Compared with injection pressure, the change of injection temperature has less effect on the wellbore pressure distribution.

6.3 Liquid Flow Rate & Gas Flow Rate

Under other conditions unchanged, the flow rate of liquid in foam was only changed. Six groups of different liquid flow rates of 5.34 m^3/h, 6.34 m^3/h, 7.34 m^3/h, 8.34 m^3/h, 9.34 m^3/h and 10.34 m^3/h were selected to calculate the wellbore pressure distribution of foam respectively, and the calculation results as shown in the following figure were obtained (Fig. 7).

If only the flow rate of gas in foam was changed, six groups of different gas flow rates of 400 Nm^3/h, 410 Nm^3/h, 420 Nm^3/h, 430 Nm^3/h, 440 Nm^3/h and 450 Nm^3/h are selected to calculate the wellbore pressure distribution of foam respectively, and the calculation results as shown in the following figure were obtained (Fig. 8).

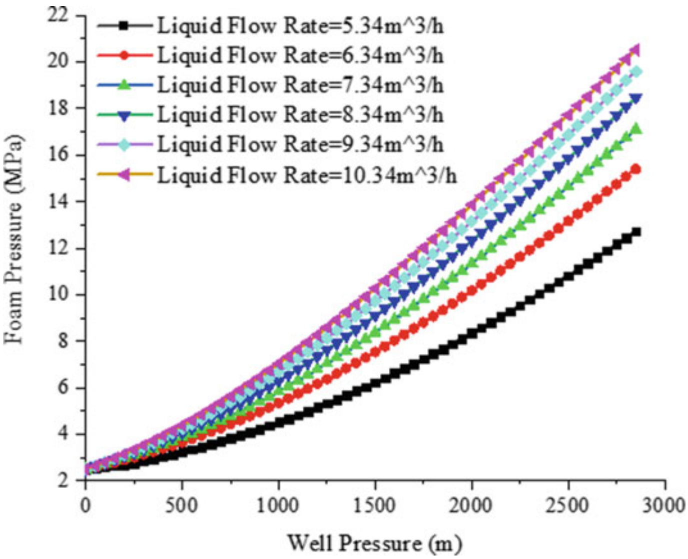

Fig. 7 Wellbore pressure distribution of foam under different liquid flow rates

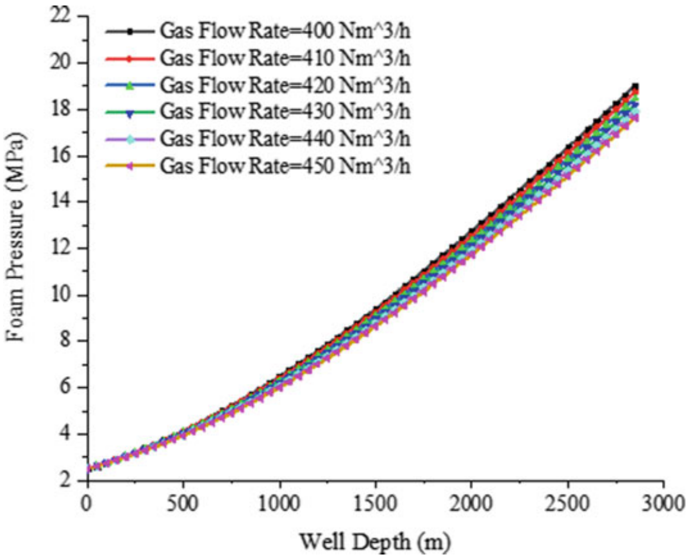

Fig. 8 Wellbore pressure distribution of foam under different gas flow rates

It can be seen from the above two figures that the bottom hole pressure increases with the increase of liquid flow rate and decreases with the increase of gas flow rate. When liquid flow rate increased from 5.34 to 10.34 m^3/h, the bottom hole pressure increased from 12.74 to 20.52 MPa. As gas flow rate increased from 400 to 450 Nm^3/h, the bottom pressure decreased from 19.02 to 17.64 MPa. Apparently, the change of liquid phase flow is more sensitive to the effect of foam pressure distribution in wellbore.

6.4 Tubing Diameter

Under the condition that the injection parameters are unchanged, six groups of different tubing inner diameters of 0.046, 0.054, 0.062, 0.070, 0.078 and 0.086 m were selected to calculate the wellbore pressure distribution of foam, as shown in Fig. 9.

It can be seen from the figure above that the bottom hole pressure increases with the increase of tubing diameter. The inner diameter of tubing increased from 0.046 to 0.086 m, and the bottom pressure increased from 14.72 to 20.39 MPa. In order to achieve a better injection effect, the tubing with a larger diameter should be selected in the early completion process.

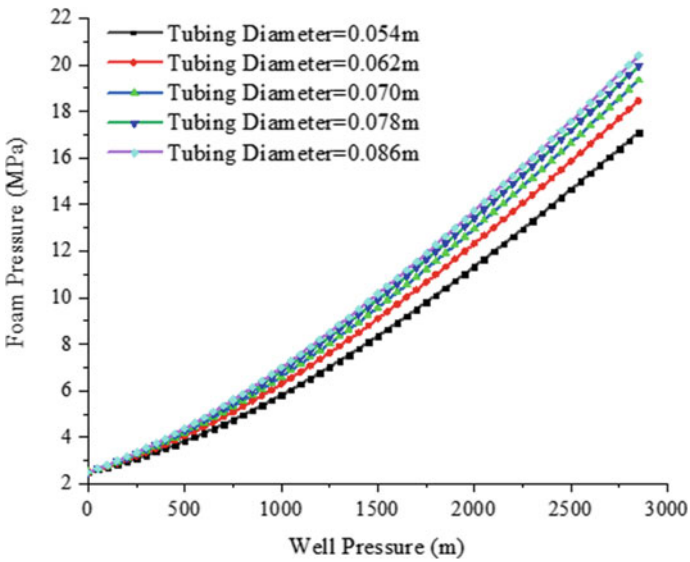

Fig. 9 Wellbore pressure distribution of foam under different tubing diameters

7 Conclusion

1. In this paper, the heat transfer calculation between the wellbore and foam was introduced in the study,and the temperature field calculation model was perfected. The rheological properties and PVT characteristics of foam fluids were considered,

and the calculation model of wellbore pressure distribution was established. Using iterative method, calculation of the whole wellbore pressure distribution during foam injection was realized.

2. Based on this model, the corresponding calculation program was compiled, and the wellbore temperature and pressure distribution of the case well were calculated. Compared with the calculation results of WELLFLO, the average relative error was 11.1%. The reason of error was analyzed and the new model meets the requirement of engineering calculation.
3. This paper analyzed sensitivity parameters and found that the total foam differential pressure of the wellbore increases with the increase of injection pressure. In addition, the bottom pressure decreases with the increase of injection temperature, increases with the increase of liquid flow rate, decreases with the increase of gas flow rate, and increases with the increase of tubing diameter.

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