Prediction and analysis of annular pressure caused by temperature effect for HP/HT/HHS and water production gas wells in Sichuan Basin

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Abstract

For the “three-high” gas wells in Sichuan Basin which are often regulated for production rate and shut-in for maintenance, annular pressure by temperature effect is a kind of wellbore safety threat that cannot be ignored. In this work, the wellbore temperature and pressure calculation model of gas–liquid two-phase flow with non-hydrocarbon correction and the prediction model of annular pressure by temperature effect is developed. Moreover, the judgment chart of annular pressure type is established through a large number of simulation calculations with different gas production rates and water production rates. Example calculation shows that whether water production and non-hydrocarbon components are considered in the prediction model has a non-negligible influence on calculation results. The predicted annular pressure is compared with that obtained from the actual measurement showing a good agreement. Meanwhile, the judgment chart realizes the valid determination of annular pressure type for three “three-high” gas wells in Sichuan Basin. Influential factors analysis indicates that reducing the thermal expansion coefficient of annulus fluid, adding the hollow glass spheres or injecting highly compressible protective liquid into the annulus and installing compressible foam material on the inner wall of casing are effective methods to control the annular pressure by temperature effect. To reserve partial annulus space can effectively reduce the annular pressure by temperature effect. For most of “three-high” gas wells in Sichuan Basin, the optimum height of annulus air cavity is 100 m.

Keywords Annular pressure · Temperature effect · Three-high gas well · Wellbore safety threat · Judgment chart

Abbreviations

T_c	Critical temperature of natural gas, °C	γ_g	Relative density of natural gas, dimensionless
p_c	Critical pressure of natural gas, MPa	v_g, v_l	True gas/liquid velocity, m/s
p_{ci}	Critical pressure of component i in natural gas, MPa	C_o	Distribution coefficient, dimensionless
T_{ci}	Critical temperature of component i in natural gas, °C	v_m	Average velocity of two-phase mixture, m/s
x_i	Mole fraction of component i in natural gas, dimensionless	v_d	Gas drift speed, m/s
$x_{H_2S}, x_{CO_2}, x_{N_2}$	Mole fraction of $H_2S/CO_2/N_2$ in natural gas, dimensionless	v_{sg}, v_{sl}	Apparent velocity of the gas and the liquid, m/s
μ_g^{un}	Uncorrected gas viscosity at atmospheric pressure and any temperature, mPa·s	H_g	Gas holdup of wellbore cross section, dimensionless
$\mu_{H_2S}, \mu_{CO_2}, \mu_{N_2}$	Viscosity correction value of $H_2S/CO_2/N_2$	β	Parameters related to section gas holdup and inundation velocity, dimensionless
		K_u	Critical Kutateladze number, dimensionless
		ρ_g, ρ_l	Gas/liquid density, kg/m ³
		σ	Surface tension, N/m
		g	Gravitational acceleration, m/s ²
		ρ_m	Density of two-phase mixture, kg/m ³
		μ_m	Viscosity of two-phase mixture, mPa·s
		μ_g, μ_l	Gas/liquid viscosity, mPa·s
		e	Absolute roughness of wellbore wall, m

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D	Diameter of wellbore, m
Re_m	Reynolds number, dimensionless
T_f	Fluid temperature in tubing, °C
q	Radial heat loss of fluid, J/s
c_{pm}	Specific heat at constant pressure of fluid, J/(kg·°C)
α_H	Joule–Thomson coefficient, °C/Pa
r_{to}	Tubing outer diameter, m
U_{to}	Total heat transfer coefficient, W·(m·°C) ⁻¹
k_e	Heat transfer coefficient of formation, W·(m·°C) ⁻¹
G_t	Mass flow rate of gas–liquid mixture, kg/s
$f(t_D)$	Dimensionless time function, dimensionless
T_e	Formation temperature, °C
U_{ta}	Annulus heat transfer coefficient, W·(m·°C) ⁻¹
r_h	Wellbore radius, m
r_{co}	Casing outer diameter, m
h_r	Radiative coefficient of annulus fluid, W·(m ² ·°C) ⁻¹
h_c	Convective heat transfer coefficient of annulus fluid, W·(m ² ·°C) ⁻¹
K_{cem}	Heat transfer coefficient of cement ring, W·(m·°C) ⁻¹
T_h	Temperature at the outer edge of cement ring, °C
T_a	Temperature in production casing annulus, °C
Δp_a	Annulus pressure change value, MPa
α_l	Thermal expansion coefficient of annulus fluid, °C ⁻¹
k_T	Isothermal compressibility of annulus fluid, MPa ⁻¹
ΔT_a	Annulus temperature change value, °C
ΔV_a	Annulus volume change value, m ³
V_a	Annulus volume, m ³
C_{tot}	Deformation coefficient of tubing and casing, 10 ⁻⁶ MPa ⁻¹
α_s	Thermal expansion coefficient of tubing and casing, 10 ⁻⁶ °C ⁻¹
p_1, p_2	Pressure before and after annular pressure change, MPa
z_1, z_2	Gas deviation coefficient before and after annular pressure change, MPa
T_{a1}, T_{a2}	Annulus temperature before and after annular pressure change, °C
V_{g1}, V_{g2}	Upper air cavity volume before and after annular pressure change, m ³

Introduction

There are some marine carbonate gas fields in Sichuan Basin, including Puguang gas field, Yuanba gas field, Moxi gas field and so on. These gas fields are characterized by high pressure (HP), high temperature (HT), high hydrogen sulfide (HHS) content, complex geological condition, water production and densely populated area. They are typical “three-high” gas fields (Li 2013; Xue et al. 2013; Su et al. 2014). Production casing annular pressure appears in almost all production wells during the exploitation of these gas fields. According to the cause of production casing annular pressure, it can be divided into annular pressure caused by temperature effect and annular pressure caused by leakage effect. The annular pressure by temperature effect is called normal annular buildup pressure, while the annular pressure by leakage effect is called abnormal annular buildup pressure (Zhu et al. 2012a, b; Zhu et al. 2012a, b; Valadez et al. 2014). Generally speaking, abnormal annular buildup pressure is the biggest threat to production safety, but for these “three-high” gas wells in Sichuan Basin which are often regulated for production rate and shut-in for maintenance, annular pressure by temperature effect is also a kind of wellbore safety threat that cannot be ignored (Singh et al. 2012; Julian et al. 2007). Frequent production regulation and shut-in for maintenance require continual pressure release to maintain pressure level, which increases safety operation risk and labor cost for these “three-high” gas wells. Therefore, it is very necessary to establish the prediction model of annular pressure by temperature effect and master its control factors. Once these control factors are acquired, corresponding parameters can be adjusted to reduce the threat of annular pressure to wellbore safety (Huerta et al. 2009; Nishikawa et al. 1999; Al-Ansari et al. 2015).

Currently, some researchers have studied the annular pressure by temperature effect and reached some useful conclusions. Adams et al. (1994) and Halal et al. (1994) established the prediction model of annular pressure by temperature effect, respectively, and identified two mechanisms responsible for annular pressure by temperature effect (fluid thermal expansion and tubing buckling). Oudeman et al. (2006) used field test data to verify the theoretical model, and the results show that theoretical model has some overestimates in predicting annular pressure. Che zhengan et al. (2010) proposed the prediction model of annular pressure caused by fluid thermal expansion for HP/HT gas wells and carried out the example calculation. Zhang bo et al. (2016) derived the calculation model of wellbore temperature distribution in deepwater oil/gas wells based on the conservation of energy law and

the heat transfer principle of multilayer cylinder walls, and proposed an iterative method to calculate the annular pressure. However, for these “three-high” gas wells in Sichuan Basin, their particularity is that gas production is accompanied by water production (the wellbore flow is gas–liquid two-phase flow); meanwhile, the produced natural gas contains hydrogen sulfide, carbon dioxide, nitrogen and other non-hydrocarbon components. Therefore, the two particularities need to be taken into account when establishing the prediction model of annular pressure by temperature effect (Oudeman et al. 1995).

In this paper, the wellbore temperature and pressure calculation model of gas–liquid two-phase flow with non-hydrocarbon correction is firstly established, and then, the prediction model of annular pressure by temperature effect is proposed in combination with two situations of whether the production casing annulus space is filled with protective liquid. Through example calculation and parameter sensitivity analysis, the law of normal annular buildup pressure is obtained and the corresponding control measures of annular pressure by temperature effect are put forward. Moreover, the judgment chart of the type of production casing annular pressure is established through a large number of simulation calculations with different gas production rates and water production rates. Meanwhile, the judgment chart is applied in actual field to realize the judgment of annular pressure type for several gas wells. The above works in this paper can provide reference for annular pressure management and risk control for similar “three-high” gas fields.

Wellbore temperature and pressure prediction model

Most of the “three-high” gas wells in Sichuan Basin produce water, ranging from several cubic meters to dozens of cubic meters. Meanwhile, the produced natural gas contains hydrogen sulfide (3.8–15.1%), carbon dioxide (4.8–8.64%), nitrogen (1.04–3.56%) and other non-hydrocarbon components. Therefore, the influence of gas–liquid two-phase flow and non-hydrocarbon components on calculation results should be considered when establishing the prediction model.

Non-hydrocarbon correction

The effect of non-hydrocarbon components such as hydrogen sulfide, carbon dioxide and nitrogen on gas physical parameters is mainly reflected by the calibration of gas deviation coefficient and gas viscosity.

For the calibration of gas deviation coefficient, the following model is adopted (Guo et al. 2000).

$$T_c = T_m - C_{wa} \quad (1)$$

$$p_c = T_c \sum_{i=1}^n (x_i p_{ci}) / [T_c + x_{H_2S}(1 - x_{H_2S})C_{wa}] \quad (2)$$

$$T_m = \sum_{i=1}^n (x_i T_{ci}) \quad (3)$$

$$C_{wa} = \frac{1}{14.5038} \left\{ 120 \left[(x_{CO_2} + x_{H_2S})^{0.9} - (x_{CO_2} + x_{H_2S})^{1.6} \right] + 15(x_{H_2S}^{0.5} - x_{H_2S}^4) \right\} \quad (4)$$

The standing calibration model is used to correct the gas viscosity.

$$\mu_g = \mu_g^{un} + \mu_{H_2S} + \mu_{CO_2} + \mu_{N_2} \quad (5)$$

$$\mu_{H_2S} = x_{H_2S} [0.00849 \lg(\gamma_g) + 0.00373] \quad (6)$$

$$\mu_{CO_2} = x_{CO_2} [0.00908 \lg(\gamma_g) + 0.00624] \quad (7)$$

$$\mu_{N_2} = x_{N_2} [0.00848 \lg(\gamma_g) + 0.00959] \quad (8)$$

Wellbore gas–liquid drift model

In the gas–liquid two-phase wellbore flow, the gas surpasses the liquid because of the difference in density of the two phases, which is generally referred to as the gas–liquid slip. Therefore, a drift model considering gas–liquid slip is established to calculate the gas holdup and fluid physical parameters at any depth of wellbore.

In the gas–liquid two-phase wellbore flow, the true gas velocity can be expressed as:

$$v_g = C_o v_m + v_d \quad (9)$$

The average velocity of the two-phase mixture is the sum of the apparent velocities of the gas and the liquid:

$$v_m = v_{sg} + v_{sl} = H_g v_g + (1 - H_g) v_l \quad (10)$$

For the distribution coefficient C_o , its expression is:

$$C_o = \frac{A}{1 + (A - 1)\gamma^2}, \quad \gamma = (\beta - B)/(1 - B), \quad 0 \leq \gamma \leq 1 \quad (11)$$

For the gas drift speed v_d , its expression is:

$$v_d = (1 - H_g C_o) C_o K_u v_c / (H_g C_o \sqrt{\rho_g / \rho_l} + 1 - H_g C_o) \quad (12)$$

$$v_c = \left[\frac{\sigma g(\rho_l - \rho_g)}{\rho_l^2} \right]^{1/4} \quad (13)$$

After determining the distribution coefficient and the gas drift speed, the gas holdup of wellbore cross section and the physical parameters of two-phase mixture can be determined:

$$\rho_m = \rho_l(1 - H_g) + \rho_g H_g \quad (14)$$

$$\mu_m = \mu_l^{(1-H_g)} \mu_g^{H_g} \quad (15)$$

Wellbore pressure model

The pressure gradient equation of gas–liquid two-phase wellbore flow can be obtained from the conservation of mass and momentum laws:

$$\frac{dp}{dz} = -\rho_m g \sin \theta - f_m \frac{\rho_m v_m^2}{2D} - \rho_m v_m \frac{dv_m}{dz} \quad (16)$$

The friction coefficient f_m is calculated by the Jain method:

$$\frac{1}{\sqrt{f_m}} = 1.14 - 2 \lg \left(\frac{e}{D} + \frac{21.25}{\text{Re}_m^{0.9}} \right), \quad \text{Re}_m = \frac{\rho_m v_m D}{\mu_m} \quad (17)$$

Wellbore temperature model

The wellbore temperature gradient equation can be acquired from the conservation of energy and the first law of thermodynamics:

$$\frac{dT_f}{dz} = \frac{dq}{c_{pm} dz} - \frac{g \sin \theta}{c_{pm}} - \frac{v}{c_{pm}} \frac{dv}{dz} + \alpha_H \frac{dp}{dz} \quad (18)$$

The heat loss of fluid from tubing to formation is:

$$\frac{dq}{dz} = -\frac{2\pi r_{to} U_{to} k_e}{G_t [r_{to} U_{to} f(t_D) + k_e]} (T_f - T_e) \quad (19)$$

Combined with Eqs. 18 and 19, the wellbore temperature gradient equation can be converted to:

$$\frac{dT_f}{dz} = -\frac{(T_f - T_e)}{A} - \frac{g \sin \theta}{c_{pm}} - \frac{v}{c_{pm}} \frac{dv}{dz} + \alpha_H \frac{dp}{dz} \quad (20)$$

where

$$A = \frac{c_{pm} G_t}{2\pi} \left(\frac{r_{to} U_{to} f(t_D) + k_e}{r_{to} U_{to} k_e} \right) \quad (21)$$

After the temperature inside tubing is determined, the temperature at the outer edge of the cementing ring can be calculated:

$$T_h = \frac{T_f f(t_D) + k_e T_e / r_{to} U_{to}}{f(t_D) + k_e / r_{to} U_{to}} \quad (22)$$

According to the heat transfer principle of series thermal resistance, the temperature in the production casing annulus can be obtained:

$$T_a = T_f - \frac{U_{to}}{U_{ta}} (T_f - T_h) \quad (23)$$

$$U_{to} = \left[\frac{1}{h_r + h_c} + \frac{r_{to} \ln \frac{r_h}{r_{co}}}{K_{cem}} \right]^{-1}, \quad U_{ta} = \left[\frac{1}{h_r + h_c} \right]^{-1} \quad (24)$$

Annular pressure prediction model by temperature effect

In most cases, the filling state of protective fluid in production casing annulus can be divided into two scenarios: One is full filling, and the other is partial filling. Therefore, the annular pressure prediction model needs to be established for the two cases, respectively.

Full filling scenario

For the case of production casing annulus is full filled with protective fluid, when the annular temperature increases the thermal expansion of annulus fluid occurs immediately. The annular pressure will go up since annulus fluid cannot expand freely. Meanwhile, as the annular pressure rises, the tubing and the casing are compressed and the annulus volume increases, which in turn reduces the annular pressure. Therefore, the annular pressure finally reaches a stable pressure value under the interaction of the two factors. The annular pressure change can be expressed as:

$$\Delta p_a = \frac{\alpha_l}{k_T} \Delta T_a - \frac{1}{k_T V_a} \Delta V_a \quad (25)$$

where

$$\frac{\Delta V_a}{V_a} = C_{tot} \Delta p_a + \alpha_s \Delta T_a \quad (26)$$

Substituting Eq. 26 into Eq. 25:

$$\Delta p_a = \left(1 + \frac{C_{tot}}{k_T}\right)^{-1} \cdot \frac{(\alpha_l - \alpha_s)}{k_T} \Delta T_a \quad (27)$$

Partial filling scenario

For the case of production casing annulus is partial filled with protective fluid, when the annular temperature increases the thermal expansion of annulus fluid occurs immediately and the volume of the upper gas cavity of the production casing annulus decreases. The annular pressure will goes up with the increase in the annulus temperature and the decrease in the upper air cavity volume. The annular pressure change can be obtained from the gas state equation:

$$\Delta p_a = p_2 - p_1 = \left(\frac{z_2 T_{a2}}{z_1 T_{a1}} \frac{V_{g2}}{V_{g1}} - 1 \right) p_1 \quad (28)$$

The volume of the upper air cavity after reduction is:

$$V_{g2} = V_{g1} - (V_a - V_{g1}) \cdot \alpha_l \quad (29)$$

For this scenario, there is also a kind of special circumstances. When the thermal expansion of annulus fluid causes the production casing annulus to change from the partial filling state to the full filling state, the annular pressure change should be determined by combining calculation methods of the above two scenarios.

Applications

Case study

In this section, a “three-high” gas well of MX121H in Sichuan Basin is selected as a test case. The pertinent basic parameters of the well are given in Table 1. The above two prediction models are used to calculate the annular temperature and the annular pressure by temperature effect for the well at a production rate of $46.2 \times 10^4 \text{ m}^3/\text{d}$.

The wellbore temperature distribution and the predicted annular pressure by temperature effect are shown in Fig. 1 and Table 2, respectively. As we can observe, as production proceeds, the produced high temperature fluid causes wellbore radial heat transfer, which leads to a significant rise in annular temperature. The average annular temperature increases from 85.8°C before production to 121.6°C after production. The rising annular temperature eventually causes a significant increase in annular pressure, reaching 32.2 MPa. The differential pressure at the packer is equal to the annular pressure plus the annulus fluid column pressure minus the flowing pressure at the packer, reaching 60 MPa. Furthermore, the downhole flowing pressure will gradually decrease and the differential pressure at the packer will continue to increase with production. Notably, the pressure rating of the used packer for most “three-high” gas wells in Sichuan Basin

Table 1 Basic parameters of the gas well of MX121H

Parameters	Value
Packer depth/m	6755
Downhole temperature/ $^\circ\text{C}$	154.7
Downhole pressure/MPa	62.3
Tubing diameter/mm	89
Density of annulus protective fluid/($\text{g}\cdot\text{cm}^{-3}$)	1.3
Thermal expansion coefficient of tubing and casing/(10^{-6}C^{-1})	18
Deformation coefficient of tubing and casing/(10^{-6}MPa^{-1})	57.8
Thermal expansion coefficient of annulus fluid/(10^{-6}C^{-1})	457
Isothermal compressibility of annulus fluid/(10^{-6}MPa^{-1})	450
Height of annulus air cavity/m	0
Outer diameter of casing/mm	193.7
Inner diameter of casing/mm	168.3
Gas production rate/($10^4\text{m}^3\cdot\text{d}^{-1}$)	46.2
Water production rate/($\text{m}^3\cdot\text{d}^{-1}$)	8
Geothermal gradient/($\text{K}\cdot\text{m}^{-1}$)	0.0204
Heat transfer coefficient of formation/[$\text{W}\cdot(\text{m}\cdot^\circ\text{C})^{-1}$]	1.73
Heat transfer coefficient of cement ring/[$\text{W}\cdot(\text{m}\cdot^\circ\text{C})^{-1}$]	0.98
Total heat transfer coefficient/[$\text{W}\cdot(\text{m}\cdot^\circ\text{C})^{-1}$]	11.36
Convective heat transfer coefficient of annulus fluid/[$\text{W}\cdot(\text{m}^2\cdot^\circ\text{C})^{-1}$]	9200
Initial annular pressure/MPa	0.1

Fig.1 Temperature distribution along the wellbore

Table 2 Comparison between the predicted and actual measured annular pressures

Position	Average temperature before production/°C	Average temperature after production/°C	Predicted annular pressure/ MPa	Actual measured annular pressure / MPa
Production casing annulus	85.8	121.6	32.2	31.7

is 70 MPa. Therefore, the annular pressure by temperature effect will make the wellbore face the greater safety risk.

Generally, annular pressure by temperature effect can be eliminated by pressure release. However, for the “three-high” gas wells in Sichuan Basin which are often regulated for production rate and shut-in for maintenance, frequent pressure release to maintain pressure level increases safety operation risk and labor cost. Therefore, it is very necessary to take control measures to reduce the annular pressure by temperature effect.

Meanwhile, from Table 2 shown, the predicted annular pressure is very close to the actual measured annular pressure, and the error is only 1.5%. The above observation indicates that the prediction model developed in this paper has high accuracy in calculating annular pressure by temperature effect.

Fig.2 Annular pressures for different water production rates

Fig.3 Annular pressures for different non-hydrocarbon contents

Influential factors analysis

Water production rate and non-hydrocarbon content

The influence of water production rate and the content of non-hydrocarbon components on annular pressure by temperature effect is illustrated in Figs. 2 and 3, respectively. As we can observe, the greater the water production rate, the higher the wellbore and annular temperature, ultimately resulting in the higher annular pressure. The water production rate has an obvious effect on the annular pressure. Meanwhile, as shown in Fig. 3, the influence law of non-hydrocarbon content on annular pressure is the same as that of water production rate. However, the impact degree of non-hydrocarbon content on annular pressure is less than that of water production rate. To sum up, water production rate and non-hydrocarbon content have a non-negligible influence on annular pressure by temperature effect. Taking no account of the two particularities in the prediction model will result in lower calculated value of annular pressure for the “three-high” gas wells in Sichuan Basin.

Thermal expansion coefficient of annulus fluid

The annular pressures by temperature effect for different thermal expansion coefficients of annulus fluid are presented in Fig. 4. The figure clearly shows that the increase in the thermal expansion coefficient gives the higher annular pressure. This is mainly because that the greater the thermal expansion coefficient, the larger the expansion volume of annulus fluid under the same temperature difference, ultimately resulting in the higher pressure acting on the pipe wall. Therefore, reducing the thermal expansion coefficient of annulus fluid is an effective method to control the annular pressure by temperature effect.

Isothermal compressibility of annulus fluid

The annular pressures by temperature effect corresponding to different isothermal compressibilities of annulus fluid are calculated, respectively, and the results are illustrated in Fig. 5. As we can observe, the annular pressure gradually decreases with the increase in the isothermal compressibility of annulus fluid, but the decline rate gradually lowers with the increase in the isothermal compressibility. The main reason for this phenomenon is that the greater the isothermal compressibility, the larger the compression volume of annulus expanding fluid under the same pressure difference, ultimately resulting in the lower pressure acting on the pipe wall. Therefore, enhancing the isothermal compressibility of annular fluid is also an effective method to reduce the annular pressure by temperature effect. Adding the hollow glass spheres or injecting highly compressible protective liquid into the annulus are the specific field applications of this method.

Fig.4 Annular pressures for different thermal expansion coefficients of annulus fluid

Fig.5 Annular pressures for different isothermal compressibilities of annulus fluid

Deformation coefficient of tubing and casing

The influence of deformation coefficient of tubing and casing on annular pressure by temperature effect is presented in Fig. 6. As shown in the figure, the annular pressure gradually decreases with the increase in the deformation coefficient of tubing and casing. It is obvious that the larger the deformation coefficient of tubing and casing, the greater the expanding annulus volume under the same pressure difference, ultimately resulting in the lower pressure acting on the pipe wall. Therefore, enhancing the deformation coefficient of tubing and casing is also an effective method to control the annular pressure by temperature effect. The installation of compressible foam material on the inner wall of casing is the specific field applications of this method.

Height of annulus air cavity

The annular pressures by temperature effect corresponding to the annulus air cavity heights of 0, 10 m, 50 m, 80 m, 100 m, 120 m and 150 m are calculated, respectively, and the

Fig.6 Annular pressures for different deformation coefficients of tubing and casing

results are illustrated in Fig. 7. As shown in the figure, the annular pressure gradually decreases with the increase in the annulus air cavity height. However, when the height of annulus air cavity reaches a critical value, the annular pressure drops very slowly. Obviously, an increase in the height of annulus air cavity means that there is more annulus volume reserved for protective fluid expansion, finally resulting in the lower pressure acting on the pipe wall. Moreover, when the reserved annulus volume is larger than the expansion of annulus fluid at the allocated production rate, the decline rate of annular pressure will be very small with the increase in the annulus air cavity height. Meanwhile, increasing the height of annulus air cavity also brings a negative effect of increasing the risk of annulus casing corrosion. Therefore, there is an optimum height of annulus air cavity at a allocated production rate. In practice, when these “three-high” gas wells are put into production, the annulus needs not to be filled with protective fluid; that is, partial annulus space can be reserved, which can effectively reduce the annular pressure by temperature effect. For most of “three-high” gas wells in Sichuan Basin with allocated production rate of $50 \times 10^4 \text{ m}^3/\text{d}$, the optimum height of annulus air cavity is 100 m.

Fig.7 Annular pressures for different heights of annulus air cavity

Fig.8 Judgment chart of the type of tubing and casing annular pressure

Judgment chart of the type of production casing annular pressure

Chart establishment

Another work done in this paper is to use the above two prediction models to calculate the annular pressures by temperature effect under different gas production rates and water production rates, and these calculated results are further used to establish a judgment chart, which can realize the rapid judgment of the type of production casing annular pressure. The specific judgment chart is presented in Fig. 8. From this figure shown, the judgment chart is divided into two regions, including the region of normal annular buildup pressure and another region of abnormal annular buildup pressure. The type of production casing annular pressure can be determined by judging which region the actual measured annular pressure is in. Notably, the judgment chart in Fig. 8 is calculated based on the geological parameters and wellbore parameters of a block in Sichuan Basin. If the judgment chart is applied to other blocks or others fields, the corresponding geological parameters and wellbore parameters used in prediction models should be updated. The specific judgment methods are as follows:

- (1) No pressure release has occurred in the production casing annulus.

The actual measured annular pressure is compared with the predicted annular pressure by temperature effect under the corresponding gas production rate and water production rate. If the actual measured value is lower than the predicted value, the type of annular pressure belongs to normal annular buildup pressure. If the actual measured value is higher than the predicted value, it indicates that there is leakage in the production casing annulus and the type of annular pressure belongs to abnormal annular buildup pressure.

- (2) Pressure release has occurred in the production casing annulus.

Firstly the previous released annular pressure is added to the actual measured annular pressure to obtain the total annular pressure. Then the total annular pressure is compared with the predicted annular pressure by temperature effect under the corresponding gas production rate and water production rate. If the total annular pressure is lower than the predicted value, the type of annular pressure belongs to normal annular buildup pressure. If the total annular pressure is higher than the predicted value, it indicates that there is leakage in the production casing annulus and the type of annular pressure belongs to abnormal annular buildup pressure.

Chart application

The established judgment chart is then applied to three “three-high” gas wells in Sichuan Basin to determine the type of production casing annular pressure. Among them, the two wells of PG27-5H and YB1-2H are judged by production data before annular pressure release, while the well of MX2-1H is judged by production data after annular pressure release.

- (1) PG27-5H

The production data of PG27-5H is presented in Fig. 9. As shown in the figure, the maximum annular pressure before pressure release is 23.4 MPa, and the corresponding gas production rate is $45.3 \times 10^4 \text{ m}^3/\text{d}$ and water production rate is $9 \text{ m}^3/\text{d}$. Combined with the judgment chart (Fig. 10) and the judgment method 1, it can be determined that the annular pressure in the production casing annulus of PG27-5H belongs to normal annular buildup pressure.

- (2) YB1-2H

The production data of YB1-2H is shown in Fig. 11. As we can observe, the maximum annular pressure before pressure release is 37.7 MPa, and the corresponding gas production rate is $54.4 \times 10^4 \text{ m}^3/\text{d}$ and water production rate is $8 \text{ m}^3/\text{d}$. Combined with the judgment chart (Fig. 12) and the judgment method

Fig. 10 Judgment of annular pressure type for PG27-5H

1, it can be determined that the annular pressure in the production casing annulus of YB1-2H belongs to abnormal annular buildup pressure.

- (3) MX121H

The production data of MX121H is illustrated in Fig. 13. As shown in the figure, the annular pressure on May 5, 2020, after two pressure releases is 20.2 MPa, and the corresponding gas production rate is $48.9 \times 10^4 \text{ m}^3/\text{d}$ and water production rate is $10 \text{ m}^3/\text{d}$. Meanwhile, according to the pressure release record in the production process, the sum of previous two pressure releases is 18.3 MPa. Combined with the judgment chart (Fig. 14) and the judgment method 2, it can be determined that the annular pressure in the production casing annulus of MX121H belongs to abnormal annular buildup pressure.

Validation of judgment results

According to the analysis result of annulus gas samples for the above three wells (Table 3), it can be determined that the annulus gas sample of PG27-5H does not contain hydrogen sulfide, indicating that there is no leakage in the production casing annulus and the type of annular pressure belongs to normal annular buildup pressure. On the contrary, the annulus gas samples of YB1-2H and MX121H both contain

Fig. 9 Production data of PG27-5H

Fig.11 Production data of YB1-2H

Fig.12 Judgment of annular pressure type for YB1-2H

Fig.14 Judgment of annular pressure type for MX121H

Fig.13 Production data of MX121H

hydrogen sulfide, indicating that there is leakage in the production casing annulus and the type of annular pressure belongs to abnormal annular buildup pressure. Therefore, the previous judgment of annular pressure type for the above three wells is validated by the analysis results of annulus gas samples.

Conclusions

- (1) The wellbore temperature and pressure calculation model of gas–liquid two-phase flow with non-hydrocarbon correction and the prediction model of annular pressure by temperature effect is developed in this work. Example calculation shows that whether water production and non-hydrocarbon components are considered in the prediction model has a non-negligible influence on calculation results of annular pressure by temperature effect. Comparison between the predicted annular pressure and the actual measured annular pressure reveals that the established prediction model has potential practical application in calculating annular pressure by temperature effect.
- (2) Through influential factors analysis, the influence law of control parameters on annular pressure by temperature effect is acquired and the corresponding control measures are put forward. Reducing the thermal expansion coefficient of annulus fluid, adding the hollow glass spheres or injecting highly compressible protective liquid into the annulus and installing compressible foam material on the inner wall of casing are effective and practical methods to control the annular pressure by temperature effect.

Table 3 Analysis result of annulus gas samples for PG27-5H, YB1-2H and MX121H

Well	N ₂ /%	CO ₂ /%	H ₂ S/%	CH ₄ /%	C ₂ H ₆ /%	Relative density	Actual density
PG27-5H	0.245	0	0	87.191	0.034	0.5498	0.6712
YB1-2H	0.234	5.732	7.784	85.280	0.036	0.6378	0.7958
MX121H	0.382	4.156	9.346	86.142	0.285	0.6453	0.7645

- (3) In practice, the annulus needs not to be filled with protective fluid; that is, partial annulus space can be reserved, which can effectively reduce the annular pressure by temperature effect. For most of “three-high” gas wells in Sichuan Basin with allocated production rate of $50 \times 10^4 \text{ m}^3/\text{d}$, the optimum height of annulus air cavity is 100 m.
- (4) The judgment chart of annular pressure type is established through a large number of simulation calculations with different gas production rates and water production rates. The chart is applied to three “three-high” gas wells in Sichuan Basin to realize the judgment of annular pressure type. Meanwhile, the analysis result of annulus gas samples verifies the validity of the judgment chart.

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