Journal of Natural Gas Science and Engineering 50 (2018) 43–54

Contents lists available at ScienceDirect

Journal of Natural Gas Science and Engineering

journal homepage: www.elsevier.com/locate/jngse

# Analysis of the wellhead growth in HPHT gas wells considering the multiple annuli pressure during production

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A R T I C L E  I N F O

*Keywords:*
HPHT
Wellhead growth
Production
Multiple annuli pressure
Temperature
Thermal properties

A B S T R A C T

In high-temperature and high-pressure (HPHT) gas wells, the wellhead growth caused by temperature and pressure effects during production might damage the well integrity. A calculation model of the wellhead growth produced by temperature and pressure effects was built. For the case well, the maximum pressures of annulus A, B and C are 64 MPa, 48 MPa and 38 MPa, respectively. The maximum production and intervention time are $114.5 \times 10^4$ $m^3$/d and 540 d, respectively. Based on the calculation process, the maximum wellhead growth is 412.7 mm. The axial load caused by the multiple annuli pressure is second only to that caused by the casing axial temperature difference. Wellhead growth increases with the annulus fluid thermal expansion coefficient and decreases with the annulus fluid isothermal compression coefficient. The increasing annulus temperature difference might aggravate the effect of annulus fluid thermal properties on the wellhead growth. Selecting the casing with greater wall thickness and lower thermal expansion coefficient can reduce the wellhead growth. The annulus width has little effect on the wellhead growth while the annulus length will significantly change the wellhead growth. The wellbore multiple annuli pressure can increase the wellhead growth prominently. The annulus pressure management shall be introduced into the production. Optimizing the well structure and production plan and installing the wellhead monitoring equipment contribute to mitigating the wellhead growth.

## 1. Introduction

When HPHT gas wells are functioning properly, gas flows at a high speed, the pipes and annulus fluid are under high temperature. Temperature differences in the uncemented casings will generate an axial load on the wellhead. In addition, annulus pressure might impose another axial load on the wellhead. If the resultant of these axial loads exceeds the locking force of the wellhead shear pin, then the wellhead may uplift, causing a gas leakage on the surface, which will threaten the service life of the HPHT gas wells. Therefore, studying the wellhead growth mechanism is important to improve well integrity. For the pipes' thermal stress and casing design, the single-string system is inadequate (Britton and Henderson, 1987), many scholars have analyzed the wellhead axial load based on the multiple-string system. Goodman and Halal (1993) computed the uniaxial and triaxial safety factors and compared single-string and multiple-string analysis with and without temperature loads. Halal et al. (1997). established simple calculation models of wellbore radial and axial load to address the multiple-string problem, including an efficient technique for solving the governing non-linear equations, which proved that conventional design might result in substantial error for free-standing structural casing strings landed in tension. Samuel and Gonzales (1999) studied the optimization of multistring casing design with complex load conditions, a new concept of wellhead growth index (WHI) was introduced. Combined with the multiple-string system calculating models, Aasen and Aadnøy (2004) established models to describe casing loads and wellhead movement during the completion (mechanical) phase and the production (thermal) phase. Wu and Knauss (2006) presented an analysis on casing and cement thermal stresses under the stated steam injection conditions with consideration of the interaction of casing-cement-formation. Mcspadden et al (Mcspadden and Glover, 2009). researched the wellhead growth and loads from first principles, paying particular attention to conductor and surface casings and some non-intuitive results. Liang (2012) discussed casing thermal behavior and wellhead movement by analyzing different casing string top of cement (TOC) and demonstrated how to minimize thermal force and reduce wellhead thermal growth by optimizing the casing cement level. Samuel et al. (2002), Lu et al. (2015), Dong et al. (2015), and Wang et al. (2015). analyzed the relationships between wellhead movement and the production policy and downhole operating conditions. Liu et al. (2015).

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https://doi.org/10.1016/j.jngse.2017.10.028
Received 26 October 2016; Received in revised form 27 October 2017; Accepted 27 October 2017
Available online 02 December 2017

presented an integrated solution for fatigue life estimation and fatigue failure analysis during the tubular design of thermal wells. Qian et al. (2014). and Xie et al. (2015). proposed corresponding preventive measures and technology for wellhead growth that commonly occurred in thermal production wells. In addition, wellhead subject to the annulus fluid thermal expansion cannot be ignored, Adams (1991) developed an FE program (ADHOC) to implement the annulus fluid heat-up problem known as multiple-string service life analysis. Maceachran and Adams (Adams and Maceachran, 1994), and Turner et al. (2010). discussed the lab and field data for the new insulating annulus fluid, which offered several advantages in reliability and performance for extreme temperature applications such as geothermal and steam injection wells. Ezell and Harrison (2008) analyzed wellbore thermal expansion effects and designed annulus fluids to reduce wellhead temperature. Many researchers proposed the annulus pressure calculation models (Hasan et al., 1998; Xu, 2002; Xu and Wojtanowicz, 2001; 2003; Mohammad and Wojtanowicz, 2014; AI-Ansari et al., 2015; Kinik and Wojtanowicz, 2011; Rocha-Valadez et al., 2014; Sathuvalli et al., 2016; Hasan et al., 2010) considering the annulus volume variation and temperature variation but have not discussed the effect of multiple annuli pressure on wellhead growth.

Thus, this paper establishes the calculation model for annulus pressure with consideration of wellbore multiple annuli transient heat transfer, and the mathematic model of wellhead growth caused by wellbore temperature and pressure effects. Temperature effects include the followings: (a) pipes axial temperature difference and (b) pipes radial temperature difference. Pressure effects include the followings: (a) multiple annuli pressure, (b) tubing pressure and (c) pressure acts on the inner and outer wall of the casings. Before key influencing factors on wellhead growth are discussed, the calculation process of the maximum wellhead growth is provided to check whether the pipes will fail in a burst/collapse and to determine the maximum production and the intervention time.

## 2. Multiple annuli pressure calculation model

Annulus temperature calculation models must be built before calculating the annulus pressure. The following assumptions were made: (1) the gas well is vertical and the tubing and casings are concentric; (2) the gas flowing in the wellbore provides a one-dimensional steady flow; (3) there is full contact between the solid surfaces; (4) the gas flowing in the wellbore is single-phase and without phase change; and (5) the gas flows at high speed in the HPHT gas well without regard to friction between the gas and the pipe wall.

### 2.1. Multiple annuli temperature calculation model

Fig. 1 shows the schematic of multiple annuli. Annulus A is the annulus between the tubing and the production casing, annulus B is the annulus between the production casing and the intermediate casing, and annulus C is the annulus between the intermediate casing and the surface casing.

The energy balance equation is written by noting the conductive heat loss to the formation, plus the convective energy transport into and out of the control volume of unit length (Hasan et al., 2003):

$$Q = \frac{\mathrm{d}(mE)}{\mathrm{d}t} + \frac{\mathrm{d}(m'E')}{\mathrm{d}t} - \frac{\mathrm{d}}{\mathrm{d}z}[w(H_s + 0.5v^2 - gz)] \tag{1}$$

where $m$ is the mass of fluid per unit depth, kg/m; $m'$ is the mass of wellbore system per unit depth, kg/m; $E$ is the internal energy of the tubing, J/kg; $E'$ is the internal energy of the wellbore system, J/kg; $w$ is the mass rate of fluid, kg/s; $H_s$ is the fluid enthalpy, J/kg; $v$ is the velocity of the fluid, m/s; z is the discretionary depth from downhole to wellhead, m; and $t$ is the production time, s.

The rise of the pipes/cement temperature account for a fraction of that in the fluid, and the steady rate in fluid flow is attained much more

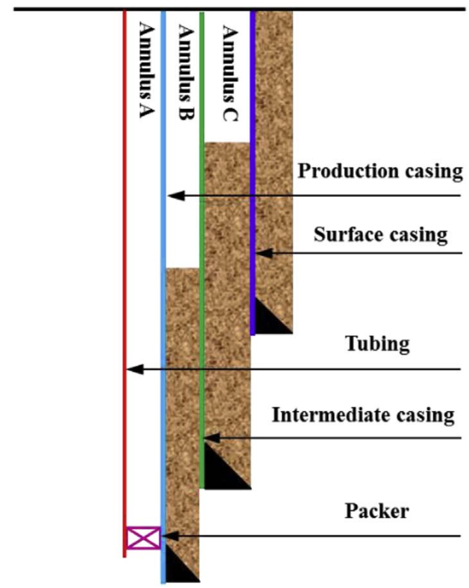


**Fig. 1.** Schematic of multiple annuli.

rapidly than stabilization of fluid temperature during the early period of the production (Spindler., 2011). Therefore, Eq. (1) is rewritten as:

$$Q = \frac{\mathrm{d}}{\mathrm{d}t}[mC_pT_f(1 + C_T)] - w\left(C_p\frac{\mathrm{d}T_f}{\mathrm{d}z} - C_JC_p\frac{\mathrm{d}p}{\mathrm{d}z} + v\frac{\mathrm{d}v}{\mathrm{d}z} - g\right) \tag{2}$$

where $C_p$ is the heat capacity of the tubing fluid, J/(kg·°C); $T_f$ is the tubing fluid temperature, °C; $C_T$ is the thermal storage parameter ($m'E'/mE$), dimensionless; $C_J$ is the Joule-Thompson coefficient, (m·°C·s$^2$)/kg; and $p$ is the pressure, MPa.

The heat lost into the formation can be written as (Lzgec et al., 2006):

$$Q = wC_p(T_d - T_f)S_R \tag{3}$$

Wherein,

$$T_d = T_{db} + y_d z \tag{4}$$

where $T_d$ is the undisturbed formation temperature, °C; $T_{db}$ is the undisturbed formation temperature at bottomhole, °C; $y_d$ is the geothermal gradient, °C/m; and $S_R$ is the wellbore heat transfer relaxation parameter, m$^{-1}$.

In Eq. (3), the $S_R$ is given by:

$$S_R = \frac{2\pi}{wC_p}\left(\frac{r_{to}U_Tk_e}{k_e + r_{to}U_TT_D}\right) \tag{5}$$

In Eq. (5), the overall heat transfer coefficient is written as:

$$U_T = \left[\frac{r_{to}}{r_{ti}h_f} + \frac{r_{to}\ln(r_{to}/r_{ti})}{k_t} + \frac{1}{h_c + h_r} + \frac{r_{to}\ln(r_{co}/r_{ci})}{k_c} + \frac{r_{to}\ln(r_b/r_{co})}{k_{cem}}\right]^{-1} \tag{6}$$

where $r_{to}$ is the outer radius of the tubing, m; $U_T$ is the overall heat transfer coefficient of the wellbore, J/(s·m$^{2}$·°C); $k_e$ is the heat conductivity of the formation, J/(s·m·°C); $T_D$ is the dimensionless temperature, dimensionless; $h_c$ is the convective heat transfer coefficient of the annulus fluid, J/(s·m$^{2}$·°C); $h_r$ is the radial heat transfer coefficient the annulus fluid, J/(s·m$^{2}$·°C); $r_{co}$ is the outer radius of the casing, m; $r_{ci}$ is the inner radius of the casing, m; $k_c$ is the heat conductivity coefficient of the casing, J/(s·m·°C); $r_{ti}$ is the inner radius of the tubing, m; $r_b$ is the wellbore radius, m; $k_t$ is the heat conductivity coefficient of the tubing, J/(s·m·°C); $k_{cem}$ is the heat conductivity coefficient of the cement sheath, J/(s·m·°C); and $h_f$ is the convective heat transfer coefficient of the tubing fluid, J/(s·m$^{2}$·°C).Wherein,