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ARTICLE

Analysis of Multiple Annular Pressure in Gas Storage Well and High-Pressure Gas Well

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ABSTRACT

In gas storage or high-pressure gas wells, annular pressure is an unavoidable threat to safe, long-term resource production. The more complex situation, however, is multiple annular pressure, which means annular pressure happens in not only one annulus but two or more. Such a situation brings serious challenges to the identification of well integrity. However, few researches analyze the phenomenon of multiple annular pressure. Therefore, this paper studies the mechanism of multi-annular pressure to provide a foundation for its prevention and diagnosis. Firstly, the multi-annular pressure is classified according to the mechanism and field data. Then the failure mechanism and function of the wellbore safety barriers in the process of passage formation are analyzed. Finally, some suggestions are put forward for identifying and controlling multi-annular pressure. The results show that gas storage wells and high-pressure gas wells have the conditions to generate pressure channels, which leads to the expansion of annular pressure from a single annulus to multiple annuli. The pressure channel is composed of the tubing string, casing string, and a cement mantle, and the failures among the three have causal and hierarchical relationships. According to the channel direction, it can be divided into two types: tubing-casing annulus to casing annulus and casing annulus to the tubing-casing annulus, of which the former is more harmful. Some measures can be considered to prevent pressure channeling, including improvement of cementing quality, revision of maximum allowable annular pressure, and suitable frequency of pressure relief.

KEYWORDS

Multiple-annular pressure; pressure channel; generation mechanism; identification and control

Nomenclature

A	Cross section area of cement mantle, cm^2
H_1	Height of gas column, m; V_{gan} is the volume of gas column, m^3
K_e	Comprehensive permeability of cement, μm^2
L	Length of cement mantle, cm; p_e is gas reservoir pressure, MPa
K_T	Isothermal compressibility of annular liquid, MPa^{-1}
Rs	Gas solubility of annular liquid, m^3/m^3
T_a	Gas temperature under standard conditions, K

p_l	Annular liquid column pressure, MPa
p_a	Gas pressure under standard conditions, MPa
p_{an}	Annular pressure, MPa
p_{anj-1}	Annular pressure in the iteration of $(j-1)^{th}$ time, MPa
T_{an}	Annular temperature, K
V_{an}	Annular volume, m^3; Q_j is gas rate in the iteration of j, m^3/s
V_g	Total gas volume invading into annulus under standard conditions, m^3
Z_a	Gas compressibility factor under standard conditions, dimensionless
Z_{an}	Gas compressibility factor in annulus, dimensionless
$\overline{\mu}$	Gas viscosity under average pressure difference, mPa·s
$\overline{Z}$	Gas compressibility factor under average pressure difference, dimensionless
Δp_a	Annular pressure, MPa
ΔV_a	Volume change of annulus, m^3
ΔT	Increase of annular temperature, °C

1 Introduction

Annular pressure is an important issue in well quality due to its high risk and relatively wide distribution. Up to now, this phenomenon has been reported in deepwater wells [1–3], shale gas wells [4], geothermal wells [5], high-pressure and high-temperature gas wells [6,7], gas storage wells [8,9], steam injection wells [10] and gas injection wells [11]. Therefore, great effort has been devoted to related research, including mechanisms, predictions, management, and mitigation.

As shown in Fig. 1, the gas storage wells and high-pressure gas wells mainly consist of tubing, casing, cement, packer, and liner hangers. The space between tubing and casing is called the A annulus, and the space between two nearby casings are the B, C, D annulus, and so on. Regarding annular pressure, multiple-annular pressure in gas storage and high-pressure gas wells should be paid greater attention to. Multiple-annular pressure means annular pressure exits in two or more annuli simultaneously. The risks are reflected in three aspects.

First is wellhead movement. According to modeling analysis [12], annular pressure can cause wellhead movement. Therefore, the wellhead movement would be higher when annular pressure exits in multiple annuli. Second, productivity and workover [13]. Generally speaking, the maximum allowable annular pressure (MAAP for short) decreases from the inner annulus to the outer annulus. Taking a high-pressure gas well, for example, the tubing-casing annulus (usually called A annulus) can bear 68.2 MPa while the annulus next to it (usually called B annulus) can only bear 35.0 MPa. If pressure channels connect A annulus and B annulus, the MAAP of the B annulus may be exceeded. As a result, the gas well has to shut-in, and workover becomes necessary, which leads to productivity loss and expensive costs; fire or groundwater pollution are such examples [14,15]. The outer annulus is usually isolated from the formation by cement mantle. Once the flammable gas enters the outer annulus through the pressure channel, the cement of the casing may lose its integrity under high annular pressure, and then the formation may be fractured. As a result, gas probably diffuses to the earth's surface or into groundwater through fractures. So fire may happen, and groundwater may be polluted. For example [16], an explosion happened in Hutchinson Town on 17 and 18 January 2001. This was caused by gas leakage from Yaggy gas storage through casing and formation fracture.

As stated above, it is important to get a clear understanding of multiple annular pressure in gas storage wells and high-pressure gas wells, thus providing support for the indemnification and mitigation of multiple-annular pressure. However, annular pressure can be caused by different mechanisms, like thermal expansion and cement integrity failure or tubing leakage. But available research rarely studies multiple annular pressure; most studies appraise one kind of annular pressure in one annulus. For example, Maiti et al. [17] applied machine learning to study annular pressure caused by thermal expansion of drilling fluid. Zhang et al. [18] built a model to simulate the sustained pressure in A annulus caused by tubing leakage. Mainguy et al. [19] explained the annular pressure in A annulus by field data and engineering logging. Demirci et al. [20] proposed stopping annular gas migration by gravity fluid to mitigate annular pressure. Rocha-Valadez et al. [21] used annular pressure to determine the integrity of gas lift valves. Dong et al. [22] listed evaluation and control methods for annular pressure, including several annuli, but the annular pressure is caused by thermal expansion in deepwater wells.

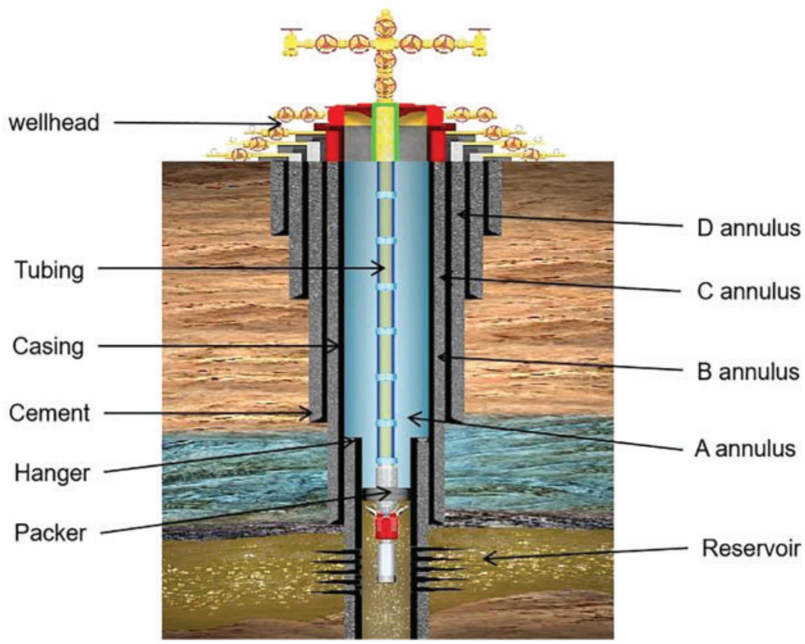

Figure 1: Graph of high-pressure gas wells and gas storage wells

These available researches are helpful in determining the sources of annular pressure, but it is difficult to judge multiple-annular pressure. Therefore, this paper conduct innovative work on the calcification and mechanism of multiple annular pressure. The cases are introduced to use field data to analyze multiple annular pressure. The risks are also compared and evaluated. The failure mechanism and function of wellbore safety barriers are analyzed to get the reason for the pressure channel. Combined with the conditions of gas storage, wells, and high-pressure gas wells, some suggestions are put forward for identifying and controlling multiple-annular pressure. This paper will reveal the formation mechanism of the pressure channels among multiple annuli. Theoretical and technical supports will also be provided for the identification of pressure channels and the prevention of multi-annular pressure.

2 Principles and Methods

2.1 Types of Annular Pressure

Despite that the phenomena observed in the wellhead are similar, the mechanisms of annular pressure are all different and can be divided into four kinds. As shown in Table 1, the first kind is caused by the operation itself. Annular pressure would increase when the casing is compressed by pressure from an operation, like a fracture. This kind is not always considered a type because it would routinely be expected to disappear when the operation in question finishes. The other three kinds are also listed in Table 1, which also compares their characteristics.

Table 1: Characteristics of annular pressure caused by different reasons

No.	Cause	Pressure source	Pressure channel	Pressure power	Recovery after releasing
1	Operation	Shrinkage of annular volume	/	Pressure imposed by operation	No
2	Thermal expansion	Annular liquid	Heat transfer	Heat from production fluid	No
3	Cement integrity failure	High pressure fluid	Comprehensive permeability of cement	Pressure different between two ends of cement	Yes
4	Tubing leakage	High pressure fluid inside tubing string	Leakage points in tubing string	Pressure difference at leakage point	Yes

2.1.1 Annular Pressure Caused by Thermal Expansion

Annular temperature would increase after the well is put into production because the production fluid brings heat from deeper within the formation. So the liquid in the annulus tends to expand but is then trapped by the annulus. Therefore, annular pressure increases to compress the liquid, thus keeping the volumes of liquid and annulus equal [23,24], as expressed by Eq. (1):

$$\Delta p_a = \left(\frac{\partial p_a}{\partial T_a}\right) \Delta T_a + \left(\frac{\partial p_a}{\partial V_a}\right) \Delta V_a + \left(\frac{\partial p_a}{\partial m}\right) \Delta m \tag{1}$$

Annular pressure caused by thermal expansion is also called trapped annular pressure. For trapped annular pressure, there is no fluid exchange outside. It can be mitigated by many measures, including thermal-isolate fluid or pipe, releasing thermal-expanded liquid, and optimizing fluid properties. Moreover, the pressure would not rebound once it is mitigated.

2.1.2 Annular Pressure Caused by Cement Integrity Failure

One of the cement's functions is to isolate the formation fluid. However, the cement is not exactly qualified for this function. Once the cement loses its integrity, the formation would invade the annulus along with the cement. This would be more severe for gas wells because gas is easy to channel. Many researchers use comprehensive permeability to present the failure degree of cement integrity, but it cannot reflect the complex process of fluid transportation within the cement. But comprehensive permeability can be used in the model of annular pressure caused by cement integrity. Eqs. (2) and (3) are examples of comprehensive permeability in the model [25,26].

$$10^{-4}R_sAH_l + V_{gan} = V_g$$

$$\frac{V_{gan}T_{an}Z_{an}p_a}{p_{an}Z_aT_a} + 10^{-4}AH_l\left(1 - p_{an}K_T\right) = V_{an} \tag{2}$$

$$Q_j = 10^{-5}\frac{K_eA}{2L}\frac{T_aZ_a}{T_{an}\overline{Z}\overline{\mu}p_a}\left[{p_e}^2 - \left(p_l + p_{anj-1}\right)^2\right] \tag{3}$$

As shown in Table 1, annular pressure caused by cement integrity failure takes cement as pressure channels. The gas is propelled by pressure differences between two ends of the cement. The pressure difference will be generated again once the annular pressure is released, so the annular pressure recovers. For this reason, it is called sustained annular pressure.

2.1.3 Annular Pressure Caused by Tubing String Leakage

According to field data, tubing leakage is the top reason for annular pressure in gas wells. The type of tubing leakage includes corrosion holes, thread leakage, packer leakage, and tubing body fractures. Sometimes, there are several leakage points in the tubing string. High-pressure gas enters the tubing-casing annulus through the leakage point(s) in the tubing string, so annular pressure increases accordingly. Usually, the small hole model is used to describe the leakage degree of tubing string leakage point, as expressed by Eq. (4) [18].

$$Q_{Lg} = \begin{cases} C_o\frac{p_{fL}A_L}{\rho_{gs}}\sqrt{\frac{2k_g}{k_g-1}\frac{M_g}{Z_gRT_{fL}}\left[\left(\frac{p_{aL}}{p_{fL}}\right)^{\frac{2}{k_g}} - \left(\frac{p_{aL}}{p_{fL}}\right)^{\frac{k_g+1}{k_g}}\right]}, & CRE < \frac{p_{aL}}{p_{fL}} \\ C_o\frac{p_{fL}A}{\rho_{gs}}\sqrt{\frac{M_gk_g}{Z_gRT_{fL}}\left(\frac{2}{k_g+1}\right)^{\frac{k_g+1}{k_g-1}}}, & CRE \geq \frac{p_{aL}}{p_{fL}} \end{cases} \tag{4}$$

The gas leakage through the tubing string leakage point(s) is also propelled by pressure differences. Likewise, it will also recover after annular pressure is released, so it is also called sustained annular pressure. Moreover, the recovery speed is usually faster than the speed of annular pressure caused by the cement integrity failure.

2.2 Analysis of Multiple-Annular Pressure

2.2.1 Classification of Multiple-Annular Pressure

According to the analysis in Section 2.1, the gas storage well and high pressure well satisfy the conditions to generate annular pressure caused by thermal expansion, and cement integrity failure and tubing string leakage. First, annular protection liquid is injected into A-annulus to prevent tubing damage and corrosion in the gas storage and high-pressure wells. Meanwhile, the production rates of the gas storage well and high-pressure gas well are so high that the temperature of the annular liquid is increased correspondingly. For example, the maximum production rate of gas storage well can be as high as 200×10^4 m^3/d. In some cases, B-annulus or C-annulus is also filled with liquid, although the cement is back to the surface. As a result, trapped annular pressure would be observed. Due to the critical downhole conditions, there is a shortage of conditions for the well barriers failure in the gas storage well and high pressure well, which will be analyzed in detail in the next section. Therefore, the multiple-annular pressure in the gas storage well and high-pressure gas well can be classified into seven types, as illustrated in Table 2. It can be found that not all types of multiple-annular pressure are caused by pressure channels among annuli.

Table 2: Types of multiple-annular pressure

Classification	Tubing-casing annulus A-annulus	Casing annulus (B, C, D . . .)	Connection & Risk
1	Thermal expansion	Thermal expansion	No well barrier fails. Risk is low and can be mitigated.
2	Thermal expansion	Cement integrity failure	Annuli are not connected by pressure channel.
3	Cement integrity failure	Thermal expansion	Annuli are not connected by pressure channel.
4	Cement integrity failure	Cement integrity failure	Annuli are connected by pressure channel. Casing and cement are the potential channel.
5	Tubing string leakage	Thermal expansion	Annuli are not connected by pressure channel.
6	Tubing string leakage	Cement integrity failure	Annuli are not connected by pressure channel.
7	Tubing string leakage	Tubing string leakage	Annuli are connected by pressure channel. Tubing, casing and cement are the potential channel.

Here, several types of multiple-annular pressure require extra explanation and analysis. Type 1, Type 2, Type 3, and Type 5 all contain annular pressure caused by thermal expansion, which the B-B test can diagnose a B-B test. B-B test is shorted for pressure bleeding-buildup test. The annular pressure caused by thermal expansion would not re-buildup after bleeding, while annular pressure caused by well integrity failure dose. Usually, the sustained annular pressure in A-annulus is caused by a tubing string leakage or leakages. Still, sometimes the integrity failures of production casing and the cement are also the potential reasons, just like Type 4. For example, sustained A-annular pressure appeared in the high-pressure wells of the Elgin and Franklin field in the UK's North Sea [19]. The detection showed that the gas invaded into A-annulus through the production casing thread, which is caused by formation deformations and general reservoir depletion. the B-B test can diagnose Type 6. Because there is no pressure channel among annuli, the pressure in other annuli does not fluctuate remarkably when the pressure in one annulus is released. Type 7 is of the highest risk because the pressure from the tubing is high and may exceed MAAP of B-annulus.

2.2.2 Field Situation of Multiple-Annular Pressure

Two typical cases are used to illustrate the multiple-annular pressure in gas storage well and high-pressure gas wells. The first case is DZ gas storage in North China. This gas storage has 14 injection-production wells and five production wells. As shown in Table 3, multiple-annular pressure appears in

8 wells [27], which translates into 42.11% of the total wells. Annular pressure appears in the A-annulus and B-annulus of the DZ gas storage. This is mainly due to the poor cement quality and tubing leakage. Annular pressure in three annuli can also be found in gas storage well, such as Well S034-22 in S gas storage.

Table 3: Multiple-annular pressure in gas storage well

Well	A-annular pressure	B-annular pressure
D2-1	4.5 MPa	6.0 MPa
D2-2	5.2 MPa	1.1 MPa
D2-3	8.0 MPa	6.4 MPa
D2-4	12.5 MPa	13.9 MPa
D5-3	7.8 MPa	4.8 MPa
D5-1	13.3 MPa	2.2 MPa
D6-1	5.7 MPa	1.8 MPa
D6-3	11.6 MPa	2.1 MPa

The other case is a high-pressure gas field in Northwest China. This gas field is faced with serious well integrity failure problems, and many advanced technologies have been previously conducted. Therefore, some gas wells are monitored in order to continue production under higher than desired annular pressure. Fig. 2 shows the annular pressure of a monitored gas well of T oilfield company. Three viewpoints can be obtained from Fig. 1. First, eight gas wells have the obvious phenomenon of multiple-annular pressure, which equals 80% of the monitored gas wells. Second, the high-pressure gas well is much more severe than the gas storage well; the pressure is high, to say the least. For example, the A-annular pressure in Well 5 is 44.56 MPa. Annular pressure exists in three annuli simultaneously in most monitored wells. Third, the A-annular pressure is usually higher than B-annular or C-annular pressure. This indicates that A-annular pressure may actually be the cause or reason for the generation of B-annular or C-annular pressure.

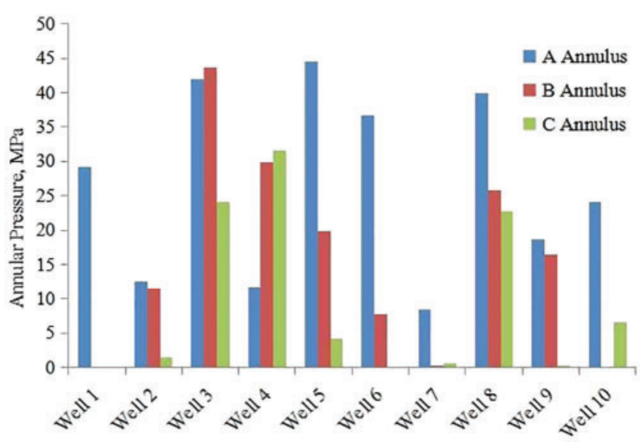

Figure 2: Multiple-annular pressure in monitored high-pressure gas wells

3 Results and Discussion

According to the above analysis, it can be noted that multiple-annular pressure is a critical issue regarding gas storage wells, as well as for high-pressure gas wells. The major kind of annular pressure is sustained annular pressure caused by a gas channel or channels. As a result, one of the reasons for the multiple-annular pressure is that pressure channels connect the annuli. Here, the pressure channel is analyzed in order to prevent multiple-annular pressure from building up.

3.1 Mechanisms of Pressure Channel and Failure

The well barriers between nearby annuli are tubing, casing, and cement, so the pressure channels also consist of them. The pressure channels can be divided into two kinds: the first consists of tubing, casings, and cement. The gas leaks from tubing through the leakage point, so A-annular pressure increases. Next, the gas invades into B-annulus through casing leakage points and through damaged cement, so B-annular pressure also increases, respectively. Likewise, the pressure can also expand to C-annulus. The other consists of just casing and cement. Gas invades into the casing annulus leading to greater, more sustained casing annular pressure. The gas then invades into the nearby annulus through casing leakage point(s), which can be either the tubing-casing annulus or nearby casing annulus. As a result, multiple-annular pressure appears in gas storage wells or high-pressure gas wells. To explain why the pressure channel generates then, it is necessary to understand how the related well barriers lose their integrity as well.

3.1.1 Tubing Failure Analysis

The integrity failure of tubing can be attributed to three factors, including load, environment, and tubing quality. The load includes the gravity of the tubing string, stimulation operation, tubing shock, annular pressure caused by thermal engineering, and formation deformation. The environment represents temperature and corrosive fluid. The tubing quality refers to its materials and manufacturing technology. Under the above factors or combination, the tubing may lose its integrity. Research showed that stress corrosion crack is a major type of tubing integrity failure that occurs in high-pressure gas wells. Other types are thread seal failures, tubing body deformation, etc. Fig. 3 is the tubing integrity failure in the gas well [6].

Tubing thread integrity failure Tubing corrosion hole

Figure 3: Leakage types of the tubing string in gas well

3.1.2 Casing Failure Analysis

Casing integrity failure can also be subdivided into tubing body and thread failure. As shown in Fig. 4, the induced causes include casing strength factors and stress distribution, which also change with time and space. Among the casing strength factors, the quality parameters include the casing yield strength, elastic modulus, wall thickness, non-uniformity, and residual stress [28]. The environment also impacts casing strength, mainly including high temperature and pressure, wear, and corrosion [29,30]. The stress distribution is related to geological and engineering load [31,32], including the uncertainty of formation information, formation plastic flow, complex pressure strata, formation slip, reservoir compaction and annular pressure, high-pressure water injection, fracturing acid, etc.

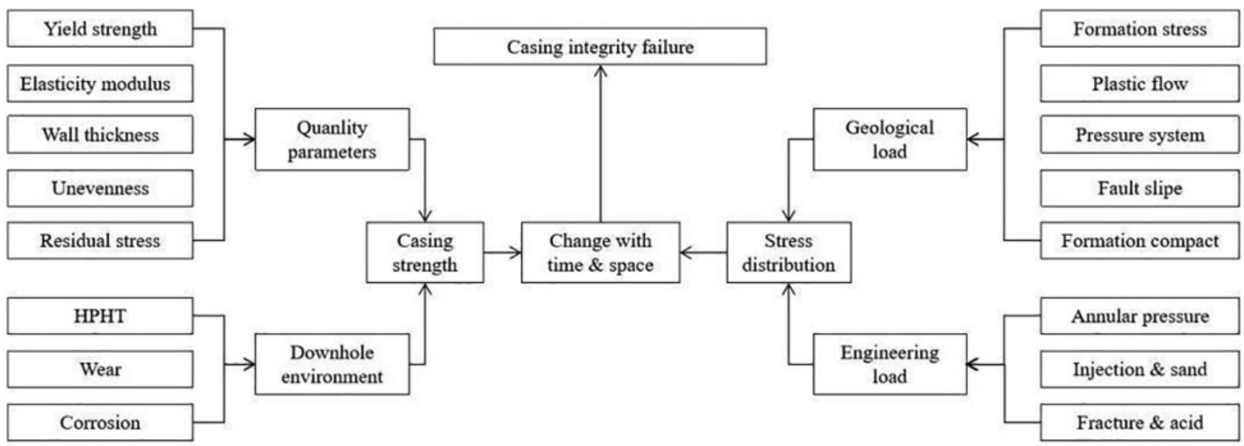

Figure 4: Causes of casing integrity failure

3.1.3 Cement Failure Analysis

The failure of cement integrity can be attributed to cement slurry properties, cement quality, perforation, corrosion, temperature, and pressure changes [33,34]. The typical failure types are fractures and micro-annulus [35–37]. During cement operation, the slurry may leak into formation, and the casing may be eccentric, so the cement quality may be poor. For example, from 2015 to 2016, 25 wells were completed in the aforementioned T oilfield, but the leakage of cement slurry happened in 15 of the 25 wells. Some particular types of cement slurry are not stable enough under high pressure and high temperature, so the cement rock's strength decreases with time. The test shows that the strength of cement rock in KeS131 Well decreases to 10.8 from 36 MPa in just 28 days under temperatures of 170°C.

3.2 Case of Multiple-Annular Pressure

For gas storage, many of the wells are old wells. After years and years of production, these old wells have integrity problems to various degrees, like casing damage and cement integrity failure. Moreover, the gas storage well is serviced as an injection and production well. The production rate is usually very high, and the injection pressure is also very high. This leads to remarkable alternating loads and threatens the integrity of the tubing, casing, and cement. The high-pressure gas well is usually a deep or even ultra-deep well, so the temperature is high and the pressure system is complex. Deep wells need longer drilling times, and as a result, the casing may be quite worn. For example, the casing at a depth of 1600 m in DB301 was well worn. The reservoir contains H_2S or CO_2 in part of the high-pressure well, such as the Puguang gas field. Also, the tubing suffers from a rather complex load due to the combination of gravity, temperature, and the water h mer effect. All of the conditions mentioned above lead to the formation of one or more pressure channels.

Here, a deep gas well is selected as the case study to illustrate the pressure channel and multiple-annular pressure. This well is 6605 m deep. The reservoir pressure and temperature are 110 MPa and 147°C, which is a typical high-pressure and high-temperature gas well. This well was put into production on 28th, May 2016. At that time, A-annular pressure was 40.11 MPa, and B-annular pressure was 40.03 MPa. Tubing pressure was 87.30 MPa, and the highest production rate approached was 50×10^4 m^3/d.

3.2.1 *History of Annular Pressure*

As shown in Fig. 5, A-annular pressure and B-annular pressure increased on 19th, August 2016, and flammable gas was released from A-annulus. Meanwhile, the liquid was released from B-annulus. Both A-annular pressure and B-annular pressure rebound quickly after release. On 7th, December 2016, flammable gas was also released from B-annulus. Through periodical releasing, B-annular pressure was controlled under 35 MPa. On 28th, Oct 2017, tubing pressure decreased sharply from 74.5 to 57.7 MPa. Meanwhile, A-annular pressure increased first and then decreased. This demonstrates that the tubing leakage was obviously aggravated. B-annular pressure and C-annular pressure then decreased with time. On 30th, Oct 2017, The pressures of A-annulus, B-annulus, and C-annulus were respectively 71.1, 42.6, and 16.6 MPa.

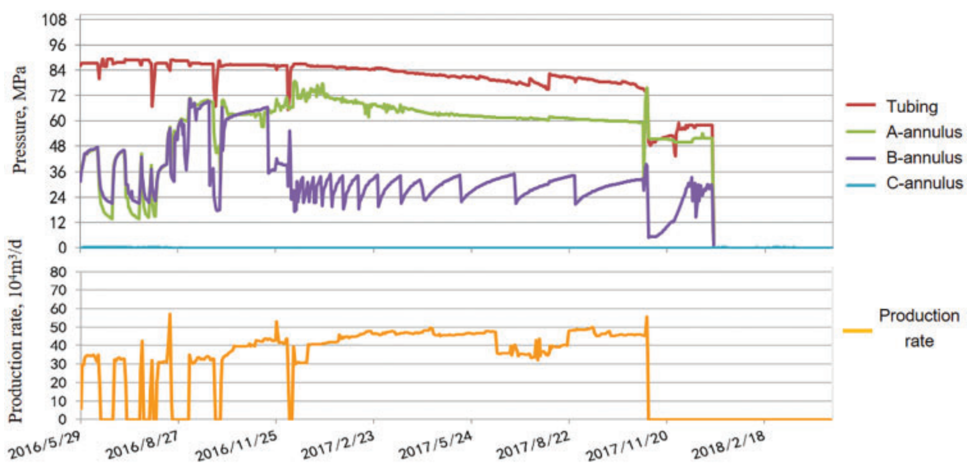

Figure 5: History of annular pressure

3.2.2 *Analysis of Multiple-Annular Pressure*

Multiple-annular pressure could be seen after the well was put into production. At that time, this was annular pressure caused merely by thermal expansion. Here is the analysis: first of all, no flammable gas was reported in the annulus. Secondly, the change of annular pressure was determined by the production rate; the annular pressure decreased when production stopped and then increased again after production was restarted once more. Third, the values of the annular pressure in the A-annulus and B-annulus were close, which is a characteristic of the annular pressure caused by thermal expansion. The multiple-annular pressure, therefore, was not of high risk at that time.

However, the situation changed on 19th, August 2016. The pressure channel formed, and annular pressure was sustained. The gas escaped from the tubing string and then entered B-annulus. Here is the analysis. First, the annular pressures were related to the tubing pressure. The sudden increase of A-annular pressure led to a sudden decrease in the tubing pressure. The pressure channel was tubing, casing, and cement. Second off, flammable gas was reported in A-annulus, as well as in B-annulus. The pressure channel was tubing, casing, and cement.

3.2.3 Pressure Channel and Proofs

The integrity failure of the tubing string was verified after the tubing string was lifted to the ground. Four leakage points were found in the tubing string. First is a hole at a depth of 1910 m. The second is the tubing deformation at the depth of 6093.86 m. The third is the tubing deformation at the 6381 m, which is under the packer. Forth is a longitudinal crack in the tubing body from 6381~6391 m, which is also under the packer. However, the first two leakage points are the key for the sustained A-annular pressure. The casing cannot be lifted from the ground. However, the high pressure in A-annulus and poor cement quality create a very easy circumstance that could bring about eventual casing integrity failure. Moreover, the highest A-annular pressure was over 80 MPa, according to Fig. 5, while the lowest anti-burst strength of casing string is 79 MPa.

Cement integrity failure is also not difficult to explain. Besides the cement quality, the high pressure in A-annulus was already in the process of bringing about micro-annulus, even if the cement quality was perfect. For the pressure in C-annulus, the quality of cement behind 365.12/339.72 mm casing can be seen in Table 4. It can be seen that almost all the cement is poor or medium in quality. So the annular pressure was transferred to the C-annulus after increased B-annular pressure.

Table 4: Quality of cement behind 365.12/339.72 mm casing

Depth, m	Cement quality	Depth, m	Cement quality
12.0~36.5	Free casing	3241.1~3321.3	Poor
~2605.6	Poor	~3331.8	Medium
~2714.7	Medium	~3346.7	Poor
~2788.7	Poor	~3354.2	Medium
~2908.3	Medium	~3419.6	Poor
~2938.4	Poor	~3516.9	Medium
~2974.7	Medium	~3586.8	Poor
~3014.1	Poor	~3609.9	Medium
~3025.1	Medium	~3632.6	Poor
~3034.8	Poor	~3644.9	Medium
~3069.4	Medium	~3649.7	Good
~3110.1	Poor	~3925.0	Medium
~3161.5	Medium	~4045.0	Poor
~3192.6	Poor	~4052.0	Not evaluated
~3241.1	Medium		

4 Conclusions

(1) Annular pressure can be divided into four particular kinds. They are each caused by operation; annular liquid thermal expansion, cement integrity failure, and tubing string leakage. Accordingly, multiple-annular pressure can be classified into seven types, but not all the types of

multiple-annular pressure are caused by pressure channels. Type 7 is at the highest risk because the pressure from tubing is high and may exceed MAAP of the outer annului.

(2) The pressure channel mainly consists of the tubing string, casing, and cement. The integrity failure of the tubing can be attributed to three factors, including load, environment, and tubing quality. Casing integrity failure can also be divided into tubing body and thread failure. The failure of the cement integrity can be attributed to cement slurry properties, cement quality, perforation, corrosion, temperature, and pressure change.

(3) Field data shows that multiple-annular pressure is one of the most serious challenges for both gas storage and high-pressure wells. They have the conditions for the formation of pressure channels. This case study verified the analysis of multiple-annular pressure and pressure channels. To prevent multiple-annular pressure, however, some measures are recommended to prevent multiple-annular pressure, including improvement of cement quality, control of A-annular pressure fluctuation, and the greater enhancement of tubing string integrity.

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