A Summary of Wellbore Fluid Accumulation and Drainage Gas Production Technology in Gas Wells

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Abstract: The problem of fluid accumulation in the wellbore of a gas well is an important factor that affects the efficiency of gas production. If the fluid accumulation is serious, the production of the gas well will decrease, and then the gas well will be flooded and stop production. It is necessary to drain the wellbore fluid to the surface in time. This article analyzes the causes and diagnostic methods of wellbore fluid accumulation, and introduces conventional fluid drainage technology such as optimization of tubing, bubble drainage, gas lift fluid drainage and mechanical fluid drainage, aiming at improving the liquid carrying capacity of gas wells and improving the gas recovery efficiency of gas wells. Examples illustrate the feasibility of drainage technology and restore normal production of gas wells.

1. Introduction

In the late 1970s, the theory of coal-derived gas was formed, and China’s domestic natural gas production scale was rapidly expanding. Today, 70% of domestic gas fields have been developed in the middle and late stages. Water production problems in gas well bores are serious, affecting gas production efficiency, which is a prominent feature of gas well production[1-2].

Scholars at home and abroad have done a lot of research on the diagnosis method of effusion. Among them, Turner RG proposed in 1969 the research method of analyzing the force of droplets in airflow, positioning the coefficient at 6.5, assuming that the droplets are spherical, and many scholars later improved and established Coleman model and Yang Chuandong model. Up to now, there have been a variety of drainage gas recovery processes, the most commonly used are bubble drainage, gas lift, mechanical drainage, and optimization of column pipes. With the successive exploration of various types of gas fields, drainage technologies must be diversified accordingly.

This article analyzes the causes of wellbore fluid accumulation, analyzes the hazards of wellbore fluid accumulation, and describes three wellbore fluid diagnosis methods using production test method, wellbore pressure loss calculation method and calculation method of critical liquid carrying capacity [3], and introduces to optimize the drainage technology such as column tube, bubble drainage, gas lift, mechanical drainage [4-8], smooth drainage of wellbore fluid is of great significance to the recovery of gas well production.

2. Causes of wellbore fluid accumulation and diagnosis methods

2.1 . Reasons

The liquid accumulated in the wellbore fluid during the gas production process of a gas well includes formation fluid, foreign fluid and condensate fluid [9]. The formation fluid is mainly caused by...
groundwater intrusion and crude oil condensed from natural gas. This part mainly exists in liquid form; condensate exists in gaseous form, mainly a collection of hydrocarbons; foreign fluid includes construction work fluid and Artificial fluid based on fracturing fluid. Depending on the nature of the gas field, the composition of the wellbore fluid is also different.

In the middle and late stages of gas well production, due to the decrease in gas well productivity, the pressure decreases. As the temperature changes from the bottom of the wellbore to the wellhead, part of the natural gas condenses into condensate during the ascent process. When the gas production rate is less than the critical flow rate, the gas flow If the energy is not enough to bring the condensate to the wellhead, the condensate will fall back to the bottom of the well and gradually accumulate to form wellbore fluid.

2.2 Diagnostic methods

2.2.1. Production test method
The production test method is a direct judgment method, which directly judges whether there is fluid accumulation in the wellbore according to the test instrument. If the gas well is in production, the electronic pressure gauge can be put into the gas well during the production process, and the vertical pressure gradient diagram of the gas well can be drawn. According to the vertical change of pressure, it can be judged whether the wellbore is fluid. If the gas well is a closed gas well with no production, the echo device can be used to detect whether the wellbore is liquid, and the height and condition of the liquid can also be detected.

2.2.2. Wellbore pressure loss calculation method
This calculation method is based on the comparison between the actual wellhead pressure and the wellhead pressure of the normal production non-accumulating wellbore. If the pressure difference is too large, it means that the wellbore has accumulated fluid. Because the density of fluid accumulation is much greater than that of natural gas, the vertical pressure of the wellbore will change abnormally. The higher the fluid level of the wellbore, the lower the actual wellhead pressure ratio. According to the actual pressure of the wellhead, it can be concluded whether the wellbore is fluid. Scholars such as Gou Sanquan, Mulin and others have researched based on data that the pressure at the bottom of the oil jacket annulus and the bottom of the tubing can be measured, and the height of the effusion can be calculated based on the difference.

2.2.3. Calculation method of critical liquid carrying capacity
During the production process of a gas well, the natural gas flow carries the liquid droplets in the wellbore to the surface. The lowest natural gas flow that can be carried by the liquid droplets to the surface is called the critical liquid-carrying flow rate, and the amount of liquid carried is the critical liquid-carrying flow rate. The reason for the accumulation of liquid in the wellbore of a gas well is that the natural gas flow rate of the gas well is lower than the critical liquid-carrying flow rate, and the droplets cannot reach the wellhead and fall to the bottom of the well to accumulate liquid accumulation.

In order to predict the critical liquid-carrying flow rate, Turner et al. analyzed the force of the droplet, derived the calculation method of the critical liquid-carrying flow rate, and established a vertical wellbore liquid-carrying flow model. Later, many scholars improved it and established the Coleman model, Li Min model, Yang Chuandong model and so on.
The above commonly used critical liquid-carrying velocity models can be written as

$$v_{cr} = \alpha \left[ \frac{\sigma (\rho_l - \rho_g)}{\rho_g} \right]^{-0.25}$$

(1)

Where:
- $v_{cr}$ — critical liquid-carrying velocity of gas well, m/s;
- $\sigma$ — surface tension, N/m;
- $\rho_l$ — liquid density, kg/m$^3$;
- $\rho_g$ — gas density, kg/m$^3$;

The formula for the critical liquid-carrying flow rate is calculated by formula (1) as

$$q_{cr} = 2.5 \times 10^4 \frac{Apv_{cr}}{Z(T + 273)}$$

(2)

Where:
- $q_{cr}$ — critical liquid carrying flow rate of gas well under standard conditions, 10$^4$m$^3$/s;
- $A$ — tubing area, m$^2$;
- $P$ — pressure, MPa;
- $Z$ — gas deviation coefficient, dimensionless;
- $T$ — temperature, °C;

3. Conventional drainage gas recovery technology

3.1. Optimizing column drainage gas recovery technology

3.1.1. Optimizing the principle of column tube process

In the middle and late stages of gas well production or the structural characteristics of the gas well itself, gas wells will always have defects such as reduced pressure in the well, insufficient jetting capacity, and reduced air flow velocity. In order to increase the liquid carrying capacity of the gas well, the maximum size with the liquid carrying capacity is calculated based on the well data Then change the column tube to the best production column tube of suitable size, reduce the inner diameter and flow cross-sectional area of the column tube, increase the gas flow speed, so that the natural gas flow has enough energy to carry the liquid to the wellhead, and solve the natural gas carrying capacity Resume normal production of gas wells. The use of this technology in inclined wells or curved wells is restricted and is not suitable for this process. Other drainage techniques can be considered.

3.1.2. Field test

In August 2008, the Dixi X well in the K gas field of the Zhungeer Basin was drilled into production with 60.3mm tubing. The accumulated continuous production was 200 days and the average daily gas production was 6.0×104m3. It can be concluded from the field production data that the optimized column tube technology can effectively discharge the liquid accumulation and ensure the stable liquid production of the gas well.
3.2 Foam drainage technology

Foam drainage [10] technology is to inject foaming agent into the bottom of the gas well containing liquid through the annulus or tubing of the oil casing. With the agitation of the high-speed flowing natural gas, the foaming agent is mixed with the bottom hole liquid and fully contacted, resulting in a large amount of the water-containing bubbles in the gas well increase the pressure in the gas well and reduce the back pressure in the well. With the energy of the natural gas flow, the bubbles are brought from the bottom of the well to the well head, and then the wellbore fluid is discharged. Defoaming is performed outside the gas gathering station to complete the gas-liquid separation and complete the gas production process.

The pros and cons of foaming agents are mainly composed of three evaluation properties: foaming ability, liquid carrying performance and foam stabilization performance, they respectively determine the foaming effect, water content and liquid film stability of the bubbles. The three evaluation parameters of the foaming agent are compared at different temperatures and pressures. They do not have a direct correlation and can be selected according to the actual conditions of the gas well.

The amount of foaming agent added is determined by the amount of fluid in the wellbore. If the concentration of injected foaming agent is too high, it will increase the back pressure of the gas well, resulting in waste, difficult to defoam, and increase drainage costs; if the injection concentration is too low, the foaming effect is not obvious, the foaming agent is too diluted by a large amount of liquid, and the bubble stability is not stable. Strong, the drainage effect is not obvious. The effusion mainly consists of three parts: annulus effusion, tubing effusion and bottom effusion. The calculation formula is as follows:

\[ Q_{\text{effusion}} = Q_{\text{annulus}} + Q_{\text{tubing}} + Q_{\text{bottom of the well}} \]  

\[ Q_{\text{annulus}} = \frac{\pi}{4} D^2 H \left( 1 - \Delta P_c C_g \right) \]  

\[ Q_{\text{tubing}} = \frac{\pi}{4} D^2 \left( H' - H \right) \]  

\[ Q_{\text{Bottom of Well}} = \frac{\pi}{4} D^2 \Delta H \]  

Where: \( Q_{\text{effusion}} \) —— wellbore effusion, kg; \( Q_{\text{annulus}} \) —— annulus effusion, kg; \( Q_{\text{tubing}} \) —— tubing fluid accumulation, kg; \( Q_{\text{well bottom}} \) —— well bottom fluid accumulation, kg; \( D \) —— The diameter of the tubing, m; \( H \) —— The depth of the tubing, m; \( H' \) —— Drilling depth at completion, m; \( C_g \) —— Isothermal compression coefficient of natural gas, \( \frac{\text{MPa}}{\text{Pa}} \); \( \Delta P_c \) —— The difference between the fully drained casing pressure and the current casing pressure, Pa; \( \Delta H \) —— Equivalent height of liquid in oil pipe, m;

The amount of foaming agent injected is related to the amount of bottom hole fluid, foaming agent concentration and foaming agent performance:

\[ Q_{\text{injection volume}} = Q_{\text{effusion}} \times C_{\text{concentration}} \times B \]  

In the formula: \( Q_{\text{injection volume}} \) —— foaming agent injection volume, kg; \( Q_{\text{effusion}} \) —— wellbore fluid accumulation, kg; \( C_{\text{concentration}} \) —— foaming agent concentration, %; \( B \) —— foaming agent performance, %;

3.3 Gas lift drainage technology

Natural gas continuous circulation (CGC) gas lift technology uses a compressor to inject natural gas into the annulus between the tubing and the casing, making it a high-speed natural gas stream, mixing with the gas produced in the gas well, and increasing the gas velocity in the wellbore. The wellbore
fluid is carried to the ground, and the separator is used for gas-liquid separation. The separated natural gas is injected into the oil jacket annulus again by the compressor, and the wellbore fluid is continuously brought to the surface to solve the problem of fluid accumulation and improve gas production efficiency.

![Schematic diagram of natural gas continuous cycle gas lift](image)

**Figure 2. Schematic diagram of natural gas continuous cycle gas lift**

In 1982, Well Wei 46 carried out a test of gas lift technology, which increased the production of natural gas by $6.59 \times 10^8$ m$^3$ in southwest Sichuan for three consecutive years. The application of this technology in Well Longgang 001-18 successfully made the well water-flooded and resumed production, achieving steady production for two consecutive years. The air volume is $1150 \times 10^4$ m$^3$.

### 3.4. Mechanical drainage and gas recovery technology

The technology is mainly to deep well pumps deep into the bottom of the bottom of the liquid accumulation liquid level, pumping the wellbore liquid to the surface. Due to the large investment, high core technology, and high cost of this drainage technology, in principle, it is suitable for situations where liquid accumulation is serious or even water flooded gas wells, and conventional drainage technology cannot be achieved. With the continuous improvement of industrial equipment and the development and application of related theories, the investment and cost will also be reduced, and it will occupy an important position in the future of drainage technology.

### 3.5. Other drainage and gas recovery technologies

In addition to the above-mentioned drainage technology, there are also ultrasonic drainage and gas extraction technology, capillary string technology, plunger gas lift, wellhead depressurization and drainage technology, etc. Each drainage technology has its advantages and disadvantages. For example, foam drainage has higher environmental requirements, mechanical drainage costs are high, it is suitable for large-scale water discharge conditions, and deep drainage has large mechanical losses. Among them, the compound liquid discharge (gas lift-bubble discharge liquid, liquid nitrogen-chemical discharge compound, etc.) has solved the shortcomings of the single liquid discharge process, but still has shortcomings. Therefore, it is very necessary to analyze the existing production data and select the appropriate drainage technology in view of different geological characteristics and water production conditions of gas wells.

### 4. Conclusion

(1) Due to the distribution of liquid surface tension along the wellbore, using the maximum critical liquid carrying flow rate as the data can improve the prediction accuracy.

(2) Optimum column drainage does not have much requirements for ground and environmental conditions, gas-liquid ratio, formation sand content and other conditions. Inclined wells or curved wells are not suitable for use; foam drainage is suitable for gas wells with small daily water production, low temperature, low pressure and low production. Large water accumulation or flooded wells are not suitable for this process, and there is no great requirement for inclined wells; the design principle of mechanical drainage mechanism is more complicated and the cost is high, suitable for large amounts of water or flooded wells.
(3) With the development of detection technology, my country’s discovered natural gas reserves have grown rapidly, and the current production gas fields have entered the late stage of serious water production, which has brought many inconveniences to the gas production process. The diversity of terrain and climate has led to drainage gas production. The technology should also be diversified. It is of great significance to find and develop new drainage gas production technology to smoothly realize the normal production of gas wells.

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