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Article

Improving Existing Drainage and Gas Recovery Technologies: An Experimental Study on the Wellbore Flow in a Horizontal Well

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Abstract: With the increasing number of horizontal wells with low pressure, low yield, and water production, the phenomenon of water and liquid accumulation in gas wells is becoming progressively more serious. In order to fix these issues, it is necessary to improve existing drainage and gas recovery technologies, increase the fluid carrying capacity of these wells, and ensure that the bottom-hole airflow has enough energy to transport the liquid to the wellhead. Among the many techniques of drainage and gas recovery, the gas lift has recently become a popular method. In the present study, through the simulation of the entire horizontal well, the flow regularity of the whole wellbore during the lift of low-pressure gas has been analyzed. The pressure distribution, liquid holdup rate, flow pattern, and energy loss (including gravity loss and friction loss) have been determined using the Beggs-brill approach. It has been found that the total pressure drop of the wellbore decreases first and increases gradually after reaching a minimum value when gas extraction is carried out via gas lift. Based on the analysis of the influence of the injection volume on wellbore pressure drop and the influence of flow pattern on the lifting efficiency, the optimal gas-lift injection parameters have been determined by taking the minimum pressure loss of wellbore as the judgment criterion.

Keywords: Horizontal well; gas-liquid two-phase flow; gas lift; flow pattern; pressure; pressure drop

1 Introduction

Horizontal wells have been widely used in oilfield development in many countries because of their long horizontal wellbore throughout the reservoir, large contact area and high gas production efficiency. However, with the increasing number of low-pressure, low-yield, and water-producing wells, the phenomenon of water-producing liquid occurs, which leads to the rapid decline of the pressure, output, and other important parameters of the gas well and seriously affects the normal production. Therefore, it is necessary to employ the drainage and gas production technology to restore the production capacity of the gas well, improve the carrying capacity of liquid, and increase the flow energy at the bottom of the well to carry the accumulated liquid to the wellhead, so as to achieve the purpose of drainage and gas production. Gas lift is an artificial lifting technology that infuses high-pressure gas into the well to mix injected gas with formation output fluid, which reduces the flow pressure drop above the injection point and improves the production capacity of the gas well accordingly. The analyses on the law of gas-liquid two-phase flow in the gas-lift wellbore as well as the optimal gas-injection parameters under different production conditions according to the influence of gas injection volume on wellbore pressure drop and gas-lift efficiency will provide a great reference and prediction for selecting appropriate drainage and gas recovery measures.

Studies on gas-liquid two-phase flow can be roughly divided into the following two categories: one category of studies is to explore the influence of low liquid content on pressure gradient through simulation experiments. Representative studies have been conducted by Hagendom et al. [1], Baroczy et al. [2], Beggs et al. [3], Fernandes et al. [4]. All these scholars established their own empirical relations based on their own experimental data, which had some limitations in the practical application. The other category of representative studies has been conducted by Taitel et al. [5], Hasan et al. [6], Chen et al. [7]. These scholars established relevant mechanism models by analyzing the physical mechanism of the flow process. However, most models were developed based on empirical relations, and the assumptions about these models were not precise enough, which led to the limited prediction accuracy of the models.

Beggs et al. [3] carried out a large number of experiments in a 15 m-long inclined transparent tube, using an air-water mixture as the experimental medium. Based on the equation of energy conservation of homogeneous flow, they obtained a formula to accurately calculate the pressure drop and liquid holdup rate of gas-liquid two-phase flow from −90° to +90°. Dukler [5] studied the flow pattern of vertical concentric annular tube with a diameter ratio of 0.5 at normal temperature and pressure, using an air-water mixture as a working medium. According to the experimental observation, he divided the annular tube flow patterns into three types: bubble flow, elastic flow, and annular flow. Chen [7] took an air-water mixture as a working medium to conduct an experimental research on the upward flow pattern of vertical annular tube under normal temperature and pressure. His classification and description of the flow pattern of the annular tube were basically similar to the results of the above researchers, except that there was no dispersed bubble-like flow or annular flow in his experiment. Kaya et al. [8], based on predecessors' research, developed a comprehensive mechanical model to further study the gas–liquid two-phase flow patterns, including the bubble flow, dispersed bubble flow, slug flow and churn flow and annular flow, and to predict the gas–liquid two-phase flow patterns, the liquid holdups and pressure drops of the vertical well and deviated well.

Bai [9] established an indoor pipeline to simulate a vertical gas well. Based on the combination of numerical simulation and experimental simulation, the multi-phase flow law of the entire wellbore before and after a gas lift in low-productivity gas wells was analyzed, and the pressure drop of the wellbore was determined based on the amount of gas injection. According to the influence of gas-lift efficiency, the optimal gas injection parameters suitable for gas lift recovery in the Sulige gas field were determined. According to the test and field data, Ren [10] further optimized the traditional model for the vertical, slanting and horizontal segments. He believed that the best prediction model was composed of the Goiver model for the horizontal segment, Gould model for the slanting segment, and Hewitt-Roberts flow pattern for the vertical segment. Liu [11] established a gas-liquid two-phase flow experiment, using a camera to capture the gas-liquid interface morphology and flow characteristics, and summarized five flow patterns and typical characteristics of horizontal gas wells. Based on Duns & Ros dimensionless gas-liquid velocity parameters, a three-dimensional flow pattern diagram was drawn to describe the gas-liquid two-phase flow in a horizontal gas well, and a method was proposed to predict the flow pattern of a horizontal gas well's wellbore with the BP neural network model.

For the gas-lift drainage gas recovery, most studies focus on predicting the pressure drop through the gas–liquid two-phase flow pressure drop model and the prediction model or predicting the optimal injection volume under different working conditions through the study of critical gas well production with parameters such as flow rate [12,13], but pay little attention to the flow law and energy loss of the whole wellbore. The flow pattern judgment model and pressure drop calculation model derived by mechanism method take the fluid parameters and tube parameters as input variables, so they have strong universality [14]. However, compared with single-phase flow, multiphase flow is more complex and has no complete theoretical basis. Therefore, it is inevitable to introduce some assumptions and approximations in the modeling process of multiphase flow [15].

In the paper, through the indoor simulation of gas–liquid two-phase flow state of a gas-lift horizontal well, the gas–liquid flow pattern changes of different sections of annular air tube were obtained; the change of gas–liquid flow law and the reason of energy loss under annular airlift were analyzed; the influence law of gas-lift injection volume on wellbore pressure was summarized; and the parameters of gas-lift injection under different production conditions were optimized.

2 Experiment

2.1 Theoretical Basis

At present, horizontal gas well liquid-carrying production has become a common phenomenon of gas field development. Different from vertical well, horizontal well has a more complicated wellbore structure, and its flow patterns will change because of the disturbance between different parts [16–18]. However, most of current studies divide a horizontal well into the horizontal section, inclined section, and vertical section separately, and independently research them according to the parameters such as gas and liquid velocity. This research method is unreliable, so it is impossible to study the gas–liquid flow pattern of the whole horizontal well.

In the process of gas–liquid two-phase flow in a horizontal well, as the inclination of the tube increases, the lower flow pattern will be destroyed by the liquid film backflow accumulation, and because the gas accumulates in the lower part of tube, it is easy to form a plunger, changing the inclined section and the vertical section [19]. In the liquid inlet condition, gas tends to accumulate in the upper part of the tube, and the liquid phase falls to disturb the rising gas and liquid in the lower part, destroying the layered structure. The flow pattern determination of a single tube section is obviously inapplicable to the gas–liquid two-phase flow law of horizontal wells [20].

By simulating the gas–liquid two-phase flow state in the gas-lift horizontal wells, the gas–liquid flow patterns of different sections of the annular tube and the law of influence on wellbore pressure were obtained. According to the influence of gas injection volume on wellbore pressure drop and gas-lift efficiency, the optimal gas injection parameters under different production conditions were analyzed to provide prediction and reference for the selection of appropriate drainage gas recovery measures.

2.2 Experimental Setup

In order to further study the wellbore flow rules of gas-lift production in horizontal wells and analyze the changes of gas–liquid two-phase flow in the wellbore, the experiment was carried out on the multi-phase flow experimental platform at Yangtze University, as shown in Fig. 1.

The laboratory parameters were set as follows: The effective pressure was 0–3.5 MPa; the length of the vertical section was 12.47 m; the length of the inclined section was 4.0 m; the inclination angle was 50°; and the length of the horizontal section was 12.47 m. The tubing was set in the vertical part with a length of 12.0 m. The experimental platform was mainly composed of a gas circuit, liquid circuit, test section, and operation control platform. The main devices in this laboratory included a liquid pump, air compressor, gas storage tank, pressure regulator, pressure sensor, flow meter, gas-liquid mixed visualization test section, and supporting equipment. The visualization test section was made of plexiglass that can withstand up to 5 MPa pressure. The air compressor provided a stable air source, followed by a gas storage tank to eliminate the influence of the air compressor on the flow in the tube. The water tank provided the liquid, and the water pump carried the liquid. The laboratory parameters are shown in Tab. 1.

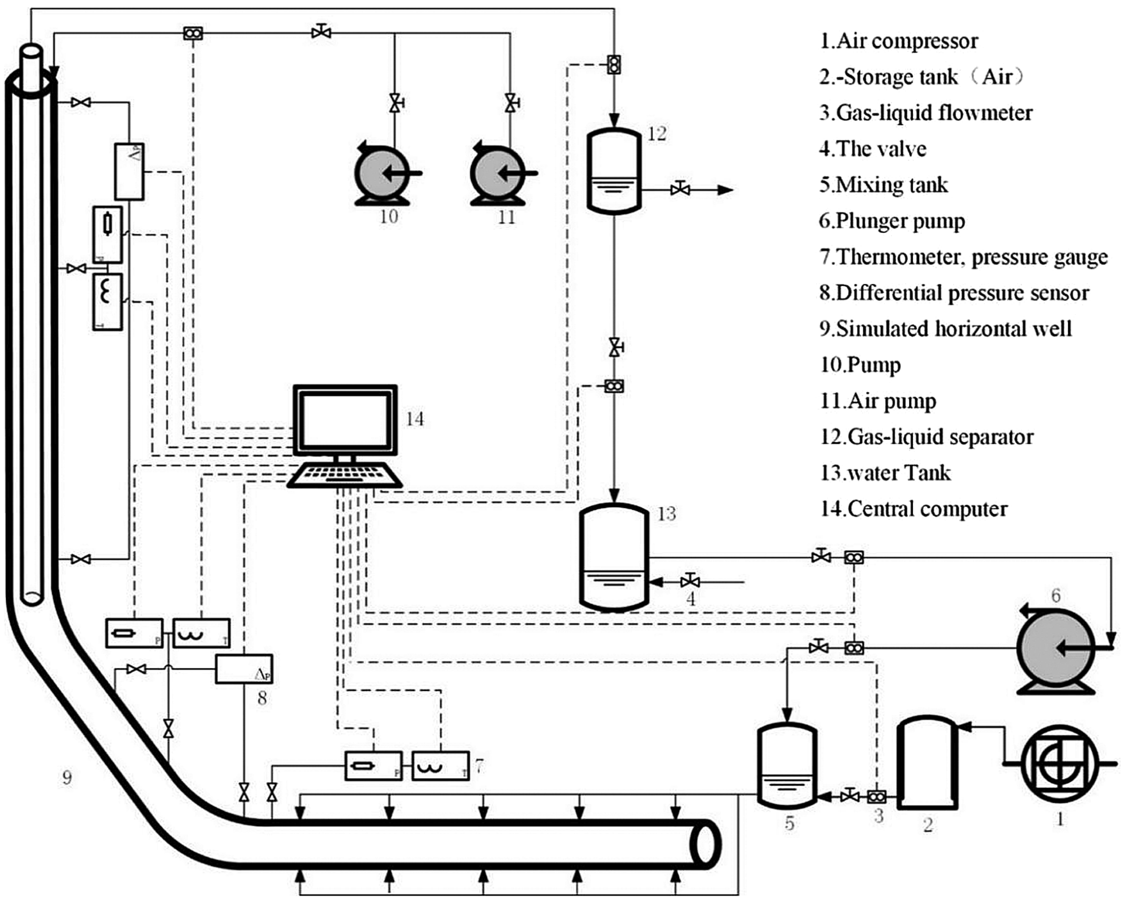

Figure 1: Experimental facility for modeling gas–liquid two-phase flow of horizontal wells

Table 1: Laboratory parameters

Laboratory parameters	Values
Casing diameter	$5^1/_2$ (inner 127.3 mm, outer 139.7 mm)
Tubing diameter	$2^7/_8$ (inner 62 mm, outer 73 mm)
Annular gas pipe	DN50
Fluid pipe	DN50
Flowmeter accuracy	±0.2%
Pressure sensor	0–4 MPa, ±0.1%
Differential pressure sensor	0–0.2 MPa, ±0.1%
Quick closing valve	<0.5 s

In the experiment, the liquid intake was adjusted by changing the ratio of the power of the liquid pump and the opening degree of the regulating valve. Air intake was also adjusted according to the above methods. The volume flow rate of the liquid phase was 50–500 m^3/d, and that of the gas-phase was 0–3 × 10^4 m^3/d. The whole experiment was conducted at room temperature, ignoring the influence of temperature on the experiment. Experimental parameters are shown in Tab. 2.

Table 2: Experimental parameters

Experimental conditions	Values
Pressure (MPa)	0–3.5
Temperature (°C)	20–25
Gas flow rate (m^3/h)	0–1250
Fluid flow rate (m^3/h)	2–20
Gas-liquid ratio	50, 100, 150, 200, 250, 300
Experimental goal	Pressure drop, liquid holding, flow pattern

The experiment was carried out at room temperature of 20–25°C. The specific steps are as follows:

(1) First, the plunger pump and the valve with corresponding flow rate were turned on. The volumes of liquid and gas flows were adjusted through the control system. The liquid was output from the water tank through the booster pump to the air compressor after the pressure became stabilized. The mixture of compressed gas into the test section was measured.

(2) The control system was observed. When the output parameters were stable and the experimental phenomena tended to be stable, and the gas–liquid distribution was carefully observed. The volume flow, temperature, pressure, and differential pressure of the gas-liquid phase in the test section were recorded in real-time within 3 minutes, and finally the effective data of the experiment was obtained.

(3) Data was recorded. The test section was closed by a quick closing valve installed at both ends of the test section. The liquid holdup was measured by a quick opening valve method. After the gas was separated by the gas–liquid separator, the liquid in the tube returned to the tank for recycling.

(4) By changing the flow rate of gas−liquid two-phase, the horizontal section, inclined section, and vertical section of liquid flow rate and gas flow rate were recorded, and the experimental results under different conditions were obtained.

2.3 Flow Pattern of Horizontal Well

The gas–liquid two-phase flow was recorded by a high-speed camera. Under the experimental conditions, it can be observed that: in the whole wellbore experiment, the flow of the horizontal section was relatively simple and mainly stratified. During the experiment, with the increase of gas flow, the horizontal section developed towards wave flow, with occasional slug flow accompanied by a small amount of backflow. The horizontal phenomenon is shown in Fig. 2. The blue arrow in the figure represents the direction of gas flow, while the black arrow represents the direction of liquid flow.

It can be seen from the experiment that the inclined section was the most complex part of the whole wellbore flow pattern change and the most concentrated area of liquid accumulation. The volume of the gas was very small, and the flow pattern was dominated by large elastic flow with unstable frequency. When the volume flow of the gas was lower than 200 m^3/h, due to the insufficient carrying capacity of the gas and liquid, the gas did not have enough energy to carry the liquid at the initial stage, and a large amount of liquid was accumulated in the low-end inclined part. Then, as the gas flow rate increased to 400–600 m^3/h, the carrying capacity of the gas–liquid two-phase increased, and the flow state was a large slug with fast frequency. When it was larger than 600 m^3/h, liquid reflux was reduced and the natural gas transportation capacity was greatly improved. The results are shown in Fig. 3. In the figure, the blue arrow is the direction of gas flow, the black arrow at the top is the direction of shallow liquid flow, and the black arrow at the bottom in the direction of liquid flow at the bottom.

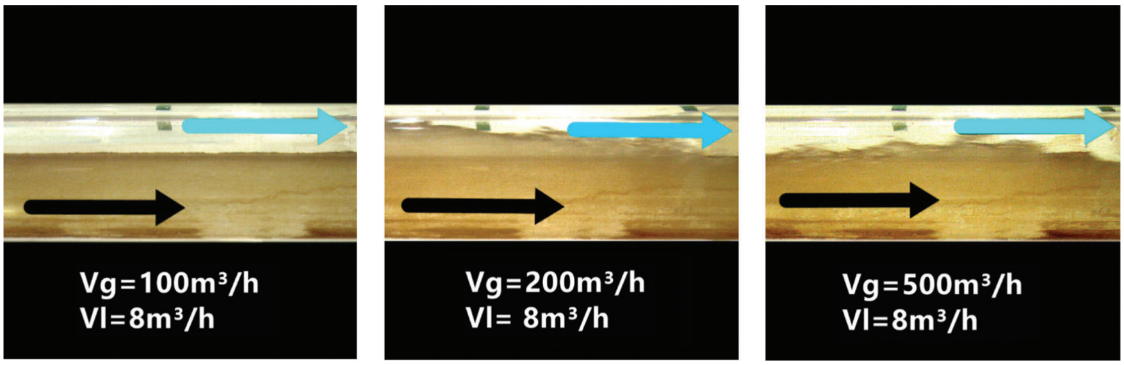

Figure 2: Flow pattern change of horizontal section

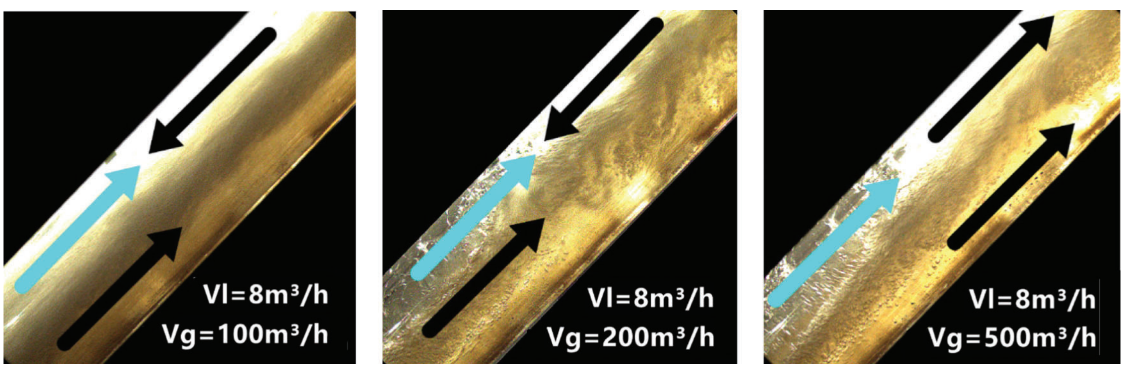

Figure 3: Flow pattern change of inclined section

Among the flow pattern changes of the whole wellbore, the flow pattern of the vertical section varied most obviously with the gas volume. When the volume flow of gas was low, the lower end of the vertical section usually flowed bubbles to the stirred flow state, and a large amount of liquid flowed back to the slug flow at the upper end. When the gas flow rate increased, the stirring flow rate increased and the airflow disturbance became serious. During the flow process of slug, the liquid flow rate was obviously accelerated and the backflow was obviously reduced. Finally, the flow was switched to a circular flow without backflow. The phenomenon is shown in Fig. 4. The blue arrow shows the direction of gas flow and the black arrow shows the direction of liquid movement.

3 Results and Analysis

In order to study the gas−liquid two-phase flow pattern of the whole horizontal well, the changes of inlet and outlet pressures, wellbore flow pattern, wellbore pressure drop, and fluid holding capacity were observed by increasing the flow rate at the gas−liquid two-phase inlet. Comparing the experimental data with several mainstream prediction models, it is found that Beggs–Brill [3] model can more accurately predict the liquid quantity of upward inclined section and vertical section. Therefore, it is recommended to use the Beggs–brill method to calculate the horizontal well pressure drop.

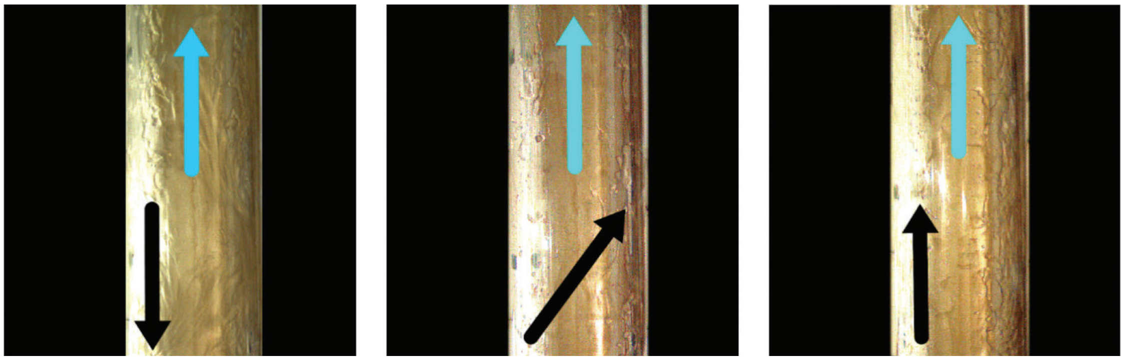

Figure 4: Flow pattern change of vertical section

$$-\frac{dp}{dz}=\frac{\left[\rho_l H_l+\rho_g(1-H_l)\right]g\sin\theta+\dfrac{\lambda G v}{2DA}}{1-\left\{\left[\rho_l H_l+\rho_g(1-H_l)\right]v v_{sg}\right\}/p} \tag{1}$$

where, P represents the pressure; Z represents the flow displacement; v_m represents the average velocity of the mixture; θ represents the Angle between the tube and the horizontal direction; ρ_l represents the liquid phase density; ρ_g represents the gas phase density; H_l represents the liquid holdup rate; G_m represents the mass flow rate of the mixture; D represents the equivalent diameter of the tube; A_p represents the flow cross-sectional area of the tube; v_{sg} represents the gas apparent flow rate. The value of liquid holdup H_l was measured in the experiment, and the gas-liquid two-phase drag coefficient λ was obtained from the formula of drag coefficient:

$$\lambda=\lambda' e^s \tag{2}$$

$$\lambda'=\left[2lg\left(\frac{\mathrm{Re}'}{4.5223lg\mathrm{Re}'-3.8215}\right)\right]^{-2} \tag{3}$$

3.1 The Pressure Drop of Horizontal Wells

Firstly, the variation law of wellbore pressure drop with the gas-liquid flow is analyzed as shown in Fig. 5. It can be concluded from Fig. 5a that the pressure drop of the wellbore was large at the beginning after gas-lift drainage, but with the increase of gas flow in the later period, the wellbore pressure gradually decreased and tended to stabilize.

Under the same liquid volume, the pressure drop gradually decreased with the increase of gas volume. When the air volume was less than 6,000 m^3/d, the pressure drop decreased rapidly with the increase of the air volume. When the air volume was greater than 6,000 m^3/d, the change of pressure drop tended to be stable and increase slowly.

It can be analyzed from Fig. 5b that under a certain gas volume, the pressure drop gradually increased with the increase of liquid volume. When the gas flow rate was low, the pressure drop was large, and with the increase of gas volume, the pressure drop gradually decreased.

As can be seen from Fig. 6, at the same liquid flow rate, wellbore pressure loss first decreased and then increased with the increase of gas–liquid ratio. It can be seen from the flow pattern experiment that the pressure drops of the wellbore became lower when the flow pattern changed from bubble-shaped flow and slug flow in the early stage to the annular flow in the later stage. When the flow pattern became the annular flow, the pressure drop loss increased, which was similar to the change of the total pressure drop of the tube.

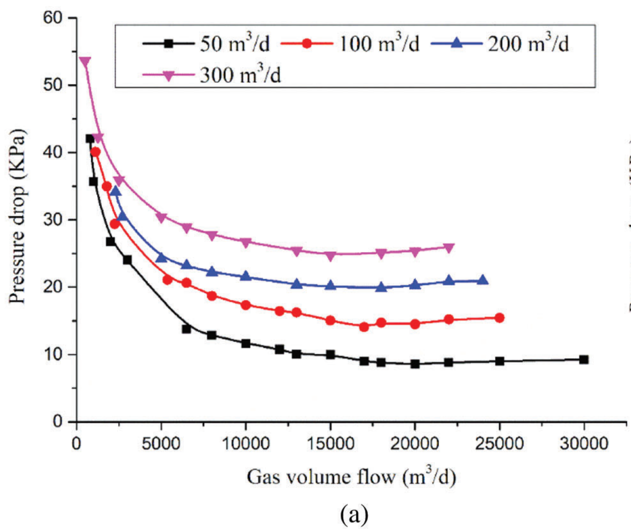

Figure 5: Variation of pressure drop during experiment (a) fixed fluid flow (b) fixed gas flow

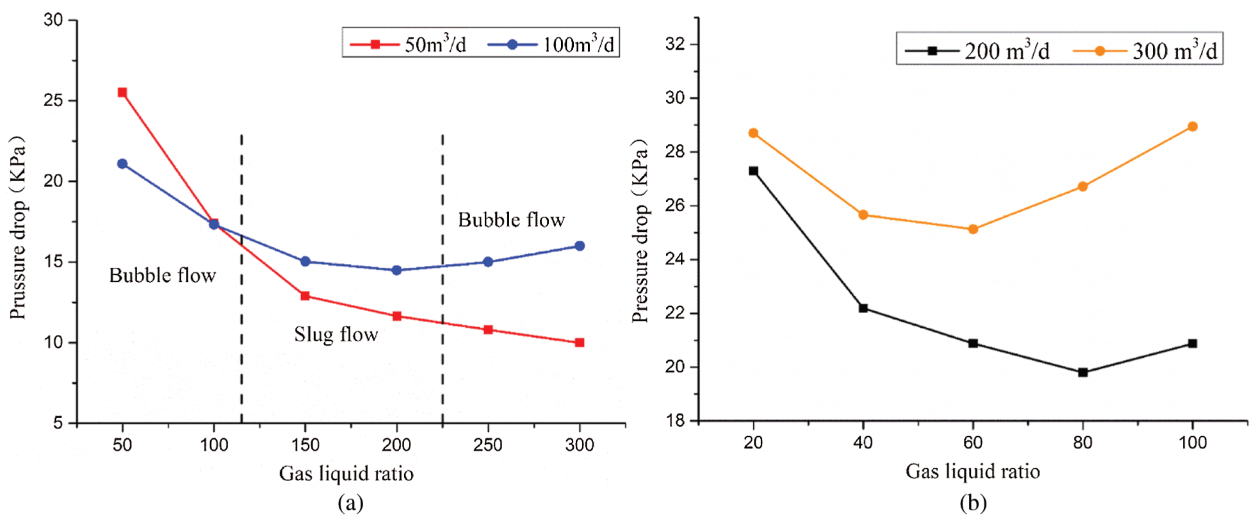

Figure 6: Pressure drop *vs.* gas-liquid ratio at the liquid volume flow

It can be seen from Fig. 6a that with the increase of the gas–liquid ratio, the pressure loss in the small liquid flow meter changes significantly. The intersection point in Fig. 6a shows that the pressure drops values of two different liquid flows (50 m^3/d and 100 m^3/d) were the same when the gas-liquid ratio was 100. As shown in Fig. 6b, when the liquid flow was 300 m^3/d, the pressure drops changed repeatedly. Through analysis, it was found that the main reason was that the backflow phenomenon between the gas and liquid with a large liquid volume lasted for a long time, leading to the accumulation of liquid at the lower end of the tube section. This resulted in a very significant change in gravity loss, which would affect the pressure drop.

3.2 Fluid Holdup in Horizontal Wells

The change law of the wellbore holding rate is shown in Fig. 7. According to the variation law of liquid holding rate in Fig. 7a, it can be concluded that, the injection of high-pressure gas in the wellbore enhanced the gas flow velocity and turbulence frequency in the wellbore, so that the liquid carrying capacity of the gas was enhanced and the wellbore effusion was carried out of the wellhead with greater energy. Under the same liquid quantity condition, with the increase of gas volume, the wellbore effusion decreased, and the liquid holdup rate decreased.

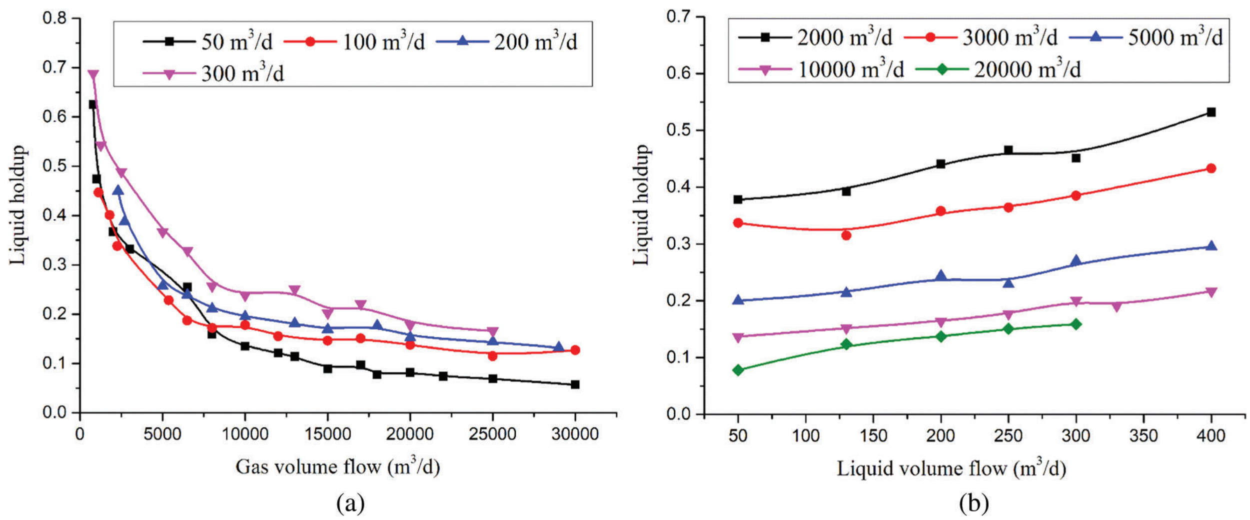

Figure 7: Variation of liquid holdup in horizontal wells (a) fixed fluid volume flow, (b) fixed gas volume flow

When the gas volume was less than 1.0×10^4 m^3/d, the liquid holding rate decreased rapidly, and when it exceeded 1.0×10^4 m^3/d, the liquid holding rate decreased slowly. The main reason was that as the air volume increased, the flow pattern gradually changed from slug flow to annular flow. After a large amount of liquid had been carried, the liquid holding rate was already very low, and the increase in air volume had little effect on the liquid holding rate.

It can be analyzed from Fig. 7b that under the same gas volume condition, with the increase in liquid volume, the liquid retention also gradually increased. In the experiment, the inclined section of the wellbore was the most serious part of liquid accumulation. By injecting high-pressure gas, the liquid accumulation structure of the inclined section was broken, and the gas turbulence space was expanded. After a large amount of accumulated liquid was discharged from the wellhead, the liquid holding capacity was reduced.

According to Fig. 8, at the same liquid volume flow, the increase in the gas–liquid ratio of the liquid holdup wellbore continued to decrease. During the experiment, it can be observed that when there was slug flow in the wellbore, the liquid holding rate was the highest at this time. As the gas volume continued to increase, the gas carried a large amount of liquid to the wellhead. When the flow pattern became the annular flow, the liquid holding rate in the tube had seldom decreased rapidly, which was consistent with the change in holding rate of the whole well section. And there was no fluid backflow phenomenon.

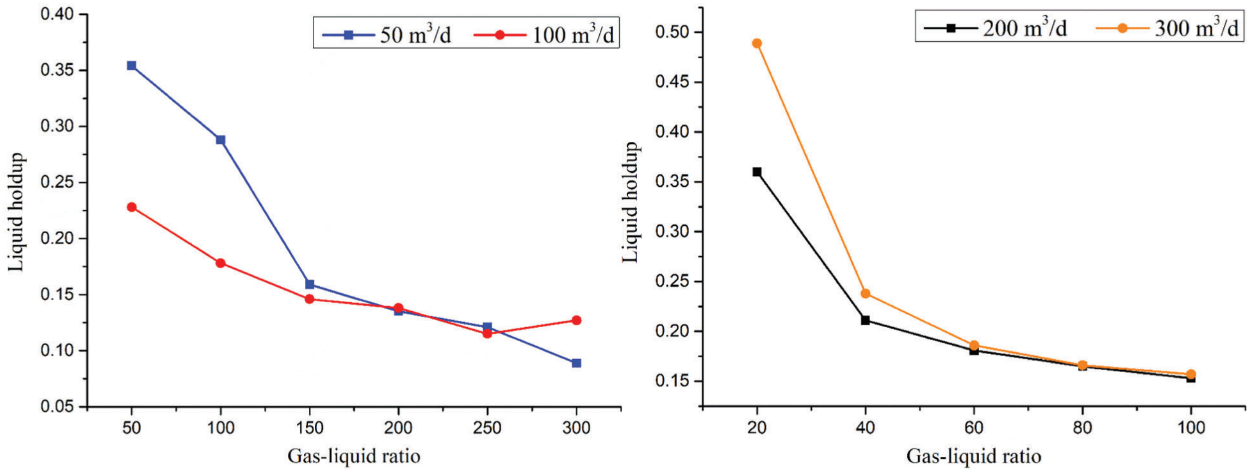

Figure 8: Liquid holdup *vs.* gas–liquid ratio at the liquid volume flow

3.3 Gravity Loss and Friction Loss

For the gas–liquid two-phase tube flow at steady state, the accelerating pressure drop was negligible. So the total pressure drop is $(\frac{dP}{dz})_t$, which can be expressed by the sum of gravity loss pressure drop and friction loss pressure drop:

$$(\frac{dP}{dz})_t = (\frac{dP}{dz})_h + (\frac{dP}{dz})_f \tag{4}$$

Combining the change of liquid holdup and pressure drop, the energy loss of gas–liquid two-phase flow in horizontal wells mainly comes from the loss of wellbore gravity and friction loss:

$$\left(\frac{dp}{dz}\right)_h = [\rho_l H_l + \rho_g(1 - H_l)]g\sin\theta \tag{5}$$

$$\left(\frac{dp}{dz}\right)_f = \lambda\frac{v_m^2}{2D}\rho = \lambda\frac{G/A}{2D}v_m \tag{6}$$

where, ρ_l represents the density of the liquid; H_l represents the liquid holdup; ρ_g represents the density of the gas; v_m represents the The velocity of the gas-liquid mixture; λ represents the frictional resistance coefficient of gas–liquid mixture, dimensionless; D represents the equivalent diameter; G represents the Flow rate for the mixture; A represents the cross-sectional area of the tube.

$$D = D_o - D_i \tag{7}$$

When the general multiphase flow calculation model is used in the calculation formula of pressure drop of multiphase flow in an annular space, the concept of equivalent diameter will be adopted. D represents the equivalent diameter; D_o represents the Inner diameter of outer tube; D_i represents the outer diameter of the inner tube.

The changes of gravity loss and friction loss of gas–liquid two-phase flow in the wellbore are shown in Figs. 9–11.

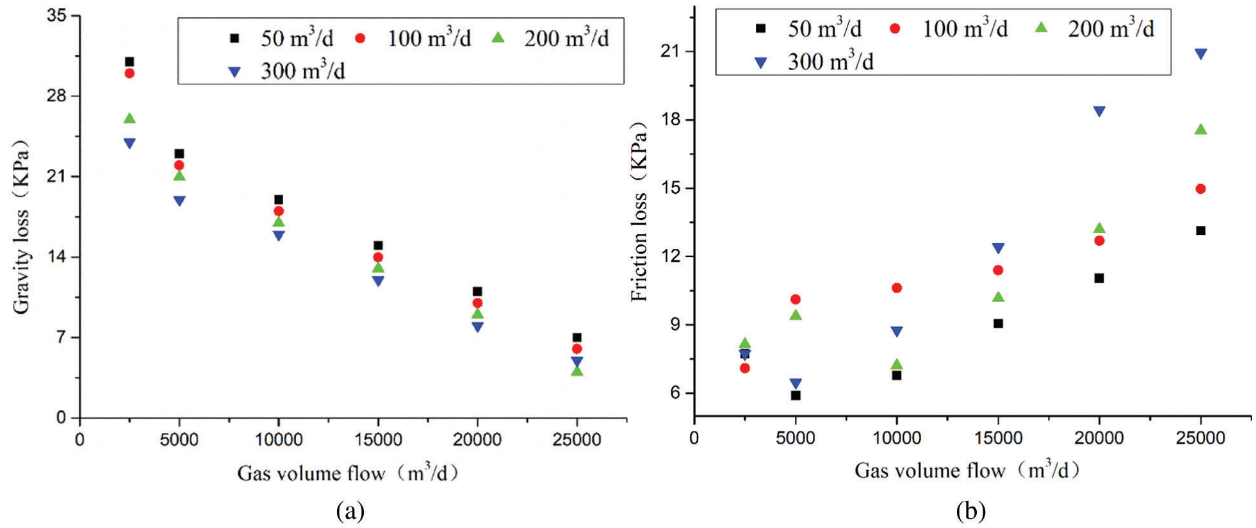

Figure 9: Variation of gravity loss and friction loss in wellbore (a) gravity loss (b) friction loss

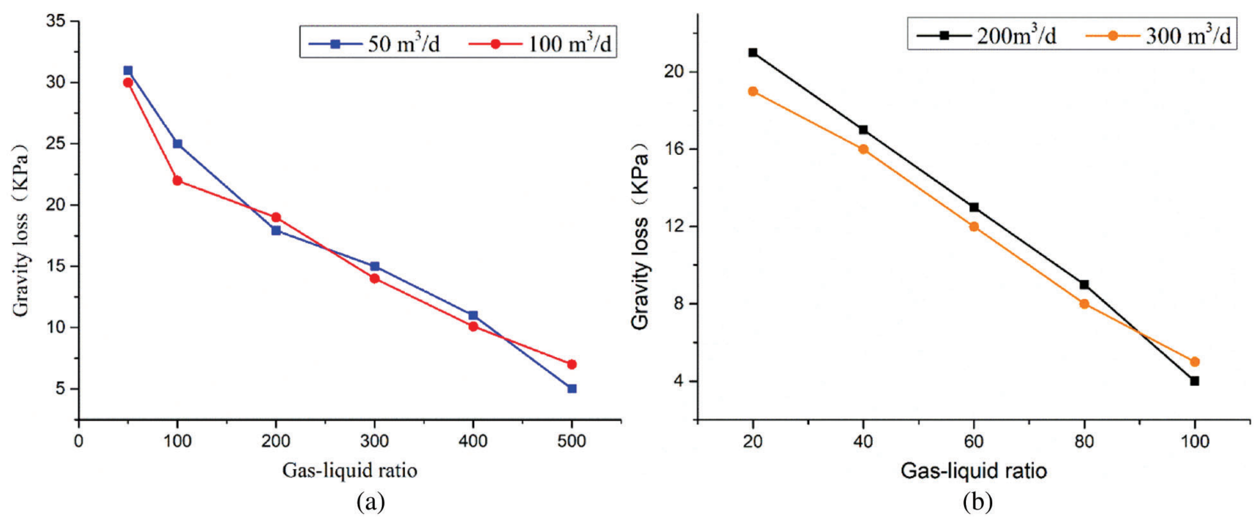

Figure 10: Gravity loss *vs.* gas–liquid ratio at different liquid volume flows

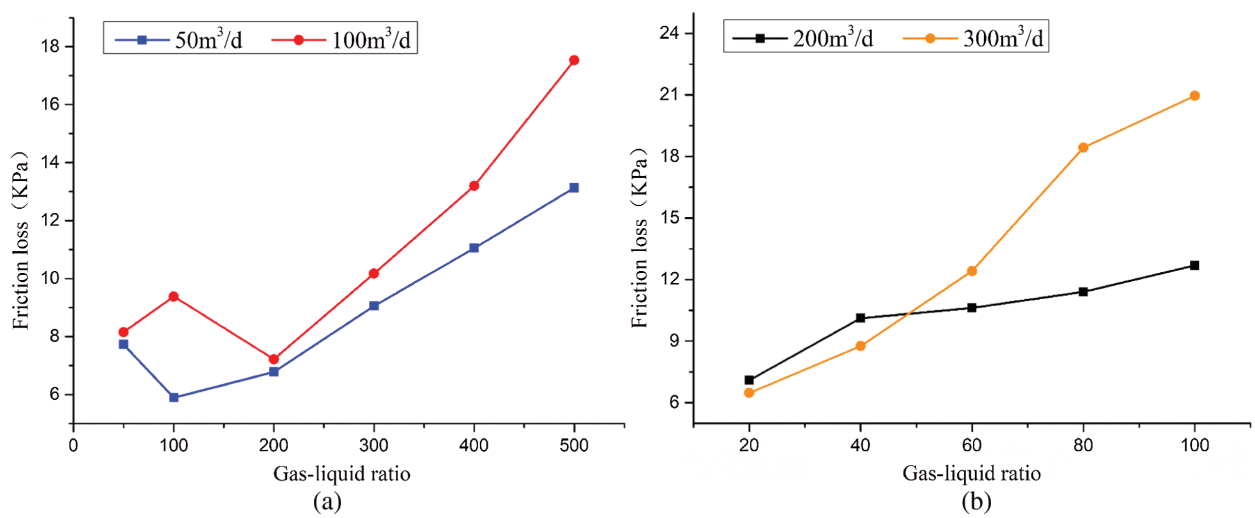

Figure 11: Friction loss *vs.* gas–liquid ratio at different liquid volume flows

According to Figs. 9–11, with the gradual increase of the gas injection volume, the gravity loss changed gradually. This is because the initial gas volume was not enough to carry liquid. At this time, the wellbore had a bubble flow and slug flow pattern. The liquid capacity was enhanced, and the gravity loss was significantly reduced after the flow pattern changed to the annular flow. Also due to the increased gas injection rate, the flow pattern changed from the wellbore bubble flow and slug flow to the annular flow, the phenomenon of friction with the wellbore wall liquid mixture increased, so that the friction losses of the wellbore increased.

As shown in Fig. 11a, when the gas-liquid ratio was 100 and the liquid volume was 100 m^3/d, there was a small fluctuation in the pressure drop. Through analysis, it was concluded that the main reason was that the backflow between the gas–liquid and the liquid increased friction between the liquid and the tube wall, which would lead to a significant change in friction loss and enhance the backflow phenomenon and the slippage effect between the gas and liquid. After the simulation of wellbore gas lift, the wellbore gas-liquid flow law, flow pattern change, lifting efficiency, and wellbore pressure drop are shown in Tab. 3.

Table 3: Simulation Parameters

Gas volume flow rate (m^3/d)	Flow pattern	Pressure drop (KPa)	Lifting efficiency (%)
<6,000	Bubble flow	42.03	9.32
6,000–8,000	Agitating flow	30.37	23.54
8,000–20,000	Slug flow	22.19	45.79
>20,000	Annular flow	18.95	17.1

Ignoring the influence of temperature, the lifting efficiency of gas lift drainage is shown as follows:

$$\eta = \frac{(p_l - \rho g H)Q_l}{p_g Q_g} \tag{8}$$

where, p_l represents the Absolute wellhead pressure; ρ represents the density of water; H represents the Wellbore height; Q_l represents the volume flow rate of produced water; Q_g represents the Volume flow rate of injected gas; p_g represents the Gas injection pressure.

As can be seen from the flow pattern data in Tab. 3, the flow pattern of gas-liquid two-phase flow in the wellbore changed from the initial bubble flow to the slug flow and the stirred flow, and finally to the annular flow with the increase of gas flow. In terms of improving efficiency, the liquid carrying capacity of bubble flow was the lowest, while the liquid carrying efficiency of slug flow was the highest. In the aspect of wellbore pressure drop, the wellbore pressure drop decreased gradually with the increase of gas volume and continued to increase gas volume. The flow pattern changed from slug flow to annular flow and then to annular fog flow. The pressure drop first decreased and then slowly increased. The results showed that there was an optimal injection volume in the wellbore during the gas lift, which could minimize the total pressure drop and energy loss. The conclusion is shown in Fig. 12.

It can be concluded from the simulation that with the increase of the gas injection volume, the total pressure drop of the entire wellbore showed a tendency of decreasing first and then increasing gradually. The gas lift was used to eliminate accumulated liquid at the bottom hole. When the pressure drop of the whole wellbore was minimum, the energy loss was minimum. At this moment, the bottom-hole gas flow has enough energy to discharge accumulated liquid from the bottom hole to the wellhead, so as to achieve stable gas production. The experimental results have shown that the minimum pressure loss and maximum liquid holdup rate were the best parameters to measure the gas-lift efficiency in gas-liquid two-phase flow.

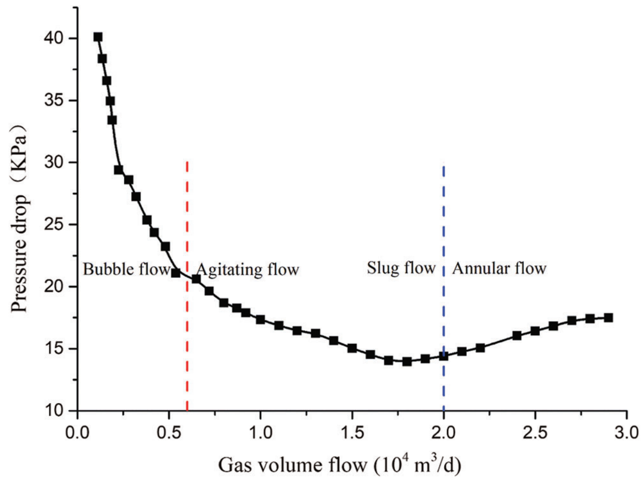

Figure 12: Effect of gas injection volume on wellbore pressure drop

4 Conclusion

The main conclusions of this research are summarized as follows:

(1) In the production of horizontal wells, the inclined section was the most serious part of liquid accumulation. High-pressure gas was injected through the gas lift to break the liquid accumulation structure, and increase the gas velocity and liquid carrying capacity of the inclined section. So that gas could carry more liquid to the wellhead, and the efficiency of liquid drainage was improved.

(2) Gas-lift efficiency was affected by multiple factors, including flow patterns, gas-liquid flow rate, and inclination angle. According to the multi-factor sensitivity analysis of gas-lift efficiency, it has been concluded that the gas-lift efficiency was the lowest when the flow pattern was bubble flow, and the slug flow had the maximum liquid carrying capacity.

(3) In the gas-liquid two-phase flow process, when the gas-liquid ratio was 50-300, the gravity loss and friction loss in the wellbore were inversely related.

(4) When other conditions remained unchanged, with the increase of gas injection volume, under the influence of factors such as liquid holding rate, flow pattern, gravity loss, and friction loss, the total pressure drop of the wellbore decreased first and then tended to increase.

(5) The experimental results showed that, among various factors, pressure drop, and liquid holdup were the best parameters for measuring energy loss in gas-liquid two-phase flow.

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