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Summary of Liquid Loading Law and Liquid Loading Prediction Model in Gas Well Wellbore

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Abstract: Gas well wellbore effusion is one of the important problems to be solved in the process of gas well development. When the problem of effusion is serious, it will lead to gas well shutdown and water flooding. The key to solve this problem lies in whether the liquid accumulation can be accurately identified and predicted in the early stage of liquid accumulation. This paper summarizes the mainstream methods of liquid accumulation identification, which are mainly divided into droplet model and liquid film model. In terms of droplet model, researchers have proposed a variety of models to predict and identify liquid accumulation in gas wells based on the force balance of droplets in gas flow. The liquid film model analyzes the stability of the liquid film, the change of the thickness of the liquid film and other factors, and establishes a variety of models to predict whether the liquid film will return, so as to determine the location of the liquid loading point and the critical liquid carrying speed. These models are not only widely used in vertical wells, but also studied and applied in complex well types such as inclined wells and horizontal wells. With the advancement of computing technology and the deepening of theoretical research, the application effect of these technologies in predicting liquid loading in gas wells has been continuously improved, which provides important support and guidance for the safe production and operation efficiency of gas wells. At the same time, the challenges faced by the research in terms of data accuracy and method applicability are analyzed. Finally, the summary evaluation of several methods is comprehensively reviewed, and the prospect of future gas well effusion identification and effusion prediction research is discussed.

Keywords: Identification of Fluid Accumulation; Fluid Accumulation Prediction; Fluid Accumulation Prediction Model.

1. Introduction

With the development and utilization of natural gas resources, the problem of wellbore fluid accumulation in gas wells has become increasingly prominent. Wellbore effusion not only affects the normal production of gas wells, but also may lead to wellbore corrosion, blockage and other problems, and even lead to the abandonment of gas wells in serious cases. Therefore, it is of great significance for gas well production to study the law of wellbore fluid accumulation and the establishment of fluid accumulation prediction model. In this paper, the research progress of gas well wellbore fluid accumulation law and prediction model in recent years is reviewed, and the different research methods are analyzed.

2. Background and Significance of Research

Gas well effusion refers to the phenomenon that the liquid accumulates in the wellbore because the gas cannot effectively carry out the liquid in the gas well. In the production process of gas wells, gas-liquid two-phase flows out of the formation and produces the ground through the wellbore. In the early stage of production, the gas production of gas wells is high, and the gas-liquid two-phase flows upward in an annular direction. The liquid is carried in two ways : the droplets entrained in the gas core and the liquid film attached to the pipe wall. As the formation pressure decreases, the gas production of the gas well decreases, resulting in that the liquid flow reversal in the wellbore cannot be taken out of the ground and liquid accumulation occurs, which seriously affects the production efficiency of the gas well.

Therefore, it is of great theoretical and practical significance to study the law of fluid accumulation in gas well wellbore and its prediction model. Through in-depth understanding and analysis of the formation mechanism of liquid loading and its movement law in the wellbore, it can provide a scientific basis for optimizing production management, reducing operational risks, and improving gas well production efficiency. The establishment of the effusion prediction model not only helps to warn the wellbore effusion in advance, but also provides support for regulating production parameters and formulating reasonable operation plans, thereby improving the overall mining efficiency and economic benefits of oil and gas fields.

3. Research Progress

3.1. Gas Well Wellbore Effusion Identification

In 1992, Li Xiaoping analyzed the causes of gas well wellbore effusion, and put forward the methods of judging gas well bottom hole effusion, including pressure gradient analysis method, empirical formula method and intuitive method.

In 2006, Gou Sanquan developed a method that only needs to calculate the location of the effusion through the pressure difference between the oil jacket, which provides a reasonable scientific basis for predicting the amount of effusion.

In 2011, based on the combination of kinetic energy factor and oil-casing pressure difference method, Zhang Jirong considered the factors such as liquid production change, oil-casing pressure fluctuation, gas production change, etc. Finally, a typical symptom analysis method was proposed, which has certain applicability in various field applications, but the value of the pressure gauge will cause a large error.

In 2012, Ma Hao developed the flow decline curve analysis method, orifice plate pressure peak method, pressure test method, etc. These methods can make a simple judgment on the liquid accumulation through the main characteristics of the liquid accumulation in the wellbore.

In 2013, Tan Bo believed that the fluid identification method studied by the predecessors was no longer applicable to the Sulige gas field. On the basis of accumulating the previous fluid identification methods, some simple methods for identifying the gas field were obtained according to the field characteristics of the gas field, which were used to determine whether the fluid was accumulated and indicate the prediction.

In 2014, on the basis of summarizing the previous research, Li Xueqin analyzed the application scope and effect of several classical methods with the deep gas wells in Daqing exploration area as the background, and used the critical liquid carrying flow rate and converted pressure to identify the effusion.

On the whole, the research on the identification of wellbore liquid loading in gas wells has made significant progress since 1992, covering a variety of methods and techniques. The research includes many methods, such as intuitive method, empirical formula method, pressure gradient analysis method, oil casing pressure difference analysis method, kinetic energy factor method and so on. It has wide applicability and can be selected and applied according to different wellbore conditions and characteristics. Most of the methods are relatively simple and do not require too many complex equipment and conditions. They can be quickly applied and verified in actual operation, which is helpful to take drainage measures in time and maintain the normal production of gas wells. From theoretical research to practical application, it covers the production of gas wells in different time periods and regions, and forms a systematic theoretical system of fluid accumulation identification, which provides a scientific basis for gas well production management. However, some methods are affected by factors such as pressure gauge accuracy and flowmeter measurement in practical applications, which limits the accuracy and accuracy of the judgment results, especially in predicting the size of the liquid volume. In addition, the applicability of different liquid loading identification methods to wellbore conditions is different. Some methods may be more effective for specific types of gas wells, while for other types of gas wells, the effect is not good, and it is necessary to select the appropriate method according to the specific situation.

3.2. Prediction Model of Wellbore Liquid Loading in Gas Wells

3.2.1. Research status of droplet model

In the early stage, most of the research on the phenomenon of liquid accumulation was based on the theory of droplet inversion. They described this theory was that the droplets first entrained into the gas flow began to fall into the wellbore. Based on this, scholars established a droplet model to predict and identify the phenomenon of liquid accumulation in gas wells.

In 1969, Turner et al. believed that the droplet fell to the bottom of the well and caused the accumulation of liquid in the well. He assumed the droplet to be spherical and obtained the critical liquid carrying velocity model by balancing the force in its vertical direction.

In 2000, the Nosseir model mainly adopted different models according to the change of Reynolds number, and the drag coefficient of the droplet will change with different Reynolds number. When Re<1000, Allens formula is used; Re in the range of 1000-20000, using Turner's unrevised model; When Re exceeds 20,000, then Turner's 20% coefficient revised model should be used, which takes into account the significant changes in flow patterns in the wellbore with flow conditions (Reynolds number) and successfully explains the difference in the droplet model (correction factor).

In 2001, Li Min et al. considered the different motion patterns of droplets under different pressure differences and other environments, and thus established a new critical flow rate model, which has been more widely used.

In 2003, Sutton et al. found that after the accumulation of fluid in a gas well, the fluid column in the wellbore would flow back within a certain period of time, and assessed the impact of this flow on the production of the gas well.

In 2004, Wu Zhijun et al. proposed a calculation method for wellbore fluid accumulation aiming at low gas-liquid ratio, using the Hagedorn-Brown method to calculate the theoretical liquid holdup at each point, and compared it with the actual situation.

In 2006, Guo and Ghalambor proposed a new liquid carrying model based on the principle of minimum kinetic energy.

In 2007, Wang Yizhong et al. proposed that the shape of the droplet in the wellbore should be a ball-cap shape, and its volume will not change, but the force area of the droplet will change due to different shapes. Therefore, the shape of the droplet will affect the drag coefficient of the model. Wang Yizhong predicted the result of the critical liquid carrying flow and increased the safety factor by 20% according to the field data. Weiner et al. then conducted experiments to record temperature and pressure when the fluids in the wellbore were in a stable state. The dimensionless constants such as Reynolds number, Ostow number and Morton number can characterize the shape of the droplet. According to the droplet morphology diagram summarized by Grace et al., Wang Yizhong obtained that the droplet shape in the process of gas liquid carrying is mainly ellipsoidal and spherical cap.

In 2019, Yang Wenming proposed a formula for calculating the critical liquid carrying velocity of inclined tubes from the force analysis of a single droplet. Yang Wenming believed that the equilibrium state of the droplet in the vertical direction is the critical state of the gas liquid carrying, but ignored the horizontal component. In practice, the horizontal component of the inclined tube always exists, which will cause the droplet to move closer to the tube wall.

In 2010, Zhou Desheng's model carried out relevant research based on Turner's existing results, assuming that the critical liquid carrying condition is mainly affected by liquid content, and droplets are not independent in the wellbore, and there will be fusion and separation between droplets, that is, droplets will separate after fusion to a certain size. When the liquid content in the gas well is lower than a certain value, the interaction between droplets is small and can be ignored. When the liquid content in the wellbore exceeds a certain value, more droplet interactions will occur. In this case, droplet interactions should be considered.

In 2012, Li Li analyzed the force of a single droplet and believed that the droplet would be unbalanced in the horizontal direction and would deviate from the center of the gas core and eventually fall on the wall of the well. Li Li analyzed the force relationship of the droplet on the wall of the well, and derived the calculation formula of the critical liquid carrying speed according to the balance relationship of friction, gravity and gas drag force. But Li Li assumed that the shape of the droplet in the well wall did not change, and the actual observation found that the droplet is generally flat.

In 2013, Tan Xiaohua et al. found that the total surface energy of a droplet is equal to the turbulent kinetic energy of a gas, and proposed a critical liquid carrying model applicable to different gas-water ratios.

In 2014, Wang Qi et al. found in the tilted tube multiphase flow experiment that liquid droplets often disappeared due to contact with liquid film on the tube wall and could not exist stably in the process of moving with gas.

In 2015, Wang et al. considered the droplet deformation factor in annular fog flow based on droplet stress balance, and also indirectly considered the influence of droplet agglomeration. In addition, when conducting experiments on two-phase flow inclined Wells and horizontal Wells, they found that droplet would flow and merge on the tube wall to form liquid film at some point. Finally, a new model for predicting the minimum critical liquid carrying velocity in gas Wells is proposed.

In 2016, Fadili et al. believed that under critical conditions, the motion velocity of droplets was the same as that of gas, that is, it was equal to the critical liquid carrying velocity of gas. The difference between the two was that droplets would collide with the wall of oil pipe, resulting in energy loss. Therefore, a new model could be established from the perspective of energy loss.

In 2018, Pan Jie et al. believed that the droplet was elliptic and calculated the maximum diameter of the windward surface. They believed that the drag coefficient was related to the droplet shape and Reynolds number, and was not just a constant. Based on the principle of conservation of energy, they proposed the relationship between critical liquid carrying velocity in gas Wells.

In 2019, Du Shejiao et al. believed that the droplet was ellipsoidal, considered the influencing factors of gas mobility and pressure, obtained the relationship between droplet deformation and the critical Weber number, and deduced the critical liquid carrying flow prediction model. At present, many experts and scholars have shown that the droplet model theory is not suitable for characterizing the phenomenon of fluid accumulation. Since the droplet reversal theory does not consider the influence of pipe diameter and tilt Angle, which are highly influential parameters for liquid accumulation judgment. In practical applications, it is often possible to judge the existence of liquid accumulation in advance. Therefore, the rationality of determining the critical liquid carrying speed by the droplet reversal theory remains to be studied.

The droplet inversion model is a method to derive the cheapest flow rate required to carry droplets based on the force equilibrium analysis of a single droplet. The force of the droplet in the gas core is related to the force area of the droplet and the drag of gas on the droplet. Therefore, the key to the droplet inversion model is to determine the drag coefficient and the droplet shape and size. The earliest droplet inversion model was proposed by Turner et al. In this model, under the assumption that the droplet is spherical, the drag coefficient of the gas core on the liquid and the maximum Weber number of the droplet are considered as 0.44 and 30 respectively. In addition, a coefficient of 1.2 is added to the model for security reasons. In view of the coefficient problem, Coleman et al. conducted a fluid accumulation study on gas Wells with wellhead oil pressure lower than 500 psi (note: 1psi=6.895 kPa) and found that the Turner model was more consistent with the prediction of fluid accumulation in low-pressure gas Wells without adding a safety factor. However, Guo et al. believe that the droplet force balance can only suspend the droplet in the gas well, but it is not enough to carry the droplet out. Only a larger gas flow rate can make the wellbore free of liquid accumulation. Therefore, based on the Turner model, a flow coefficient of 1.2 should be added. In view of droplet size and shape, Nosseir et al believed that the drag coefficient of the gas core on the droplet was different under different flow patterns (laminar flow, transitional flow, turbulent flow), and the assumption of Turner model was still adopted for droplet size and shape. Li Min et al. believed that the pressure difference on the surface of the droplet caused by the different pressure before and after the droplet in the gas core caused the droplet to be deformed into an ellipsoid shape, resulting in a larger force area. In practical derivation, the model reduces the droplet to a cylinder for differential solution, and its coefficient is only 38% of the Turner model coefficient. Based on the Li Min model, Wang Zhibin et al. derived the relationship between the droplet deformation characteristic parameters and the critical Weber number by integrating the internal energy change of the droplet and the external work being equal in the process of droplet deformation, and thus obtained a new coefficient considering the maximum droplet size and droplet deformation. In addition, Wang Zhongyi et al. established the minimum critical liquid carrying capacity model of ball-cap droplets. Tan Xiaohua et al. proposed a new model considering the influence of liquid volume and maximum droplet diameter on the critical liquid carrying flow in terms of the equal relationship between the total surface energy of droplets in airflow and the turbulent kinetic energy of gas.

The above models are established for vertical gas Wells, but there are few related studies in horizontal Wells. Belfroid et al. added the Angle correction term on the basis of Turner model, but they believed that the root cause of liquid film inversion was fluid accumulation. Shi et al. conducted experiments to observe the change of droplet shape with size under different inclination angles, and proposed a critical liquid carrying volume model based on the "half Hamburg" shaped droplet in the vertical section, the inclined section and the horizontal section respectively. Fadili et al. considered the droplet movement in the inclined section as elastic collision. They believe that after the droplet collides with the wall of the oil pipe, its movement direction changes, and the velocity required before the collision can be calculated according to the impact energy loss, that is, the critical liquid carrying gas velocity.

3.2.2. Research Status of Liquid Film Model

Different from the droplet model, the liquid film model infers that the liquid film must flow upward mainly along the tube wall, and the time when it begins to flow downward can be defined as the liquid accumulation point. Many researchers have established models to determine the initial effusion point based on the liquid film inversion theory.

In 1969, Wallis mainly argued that Pushkina's model has a higher predictive effect on vertical gas Wells with larger wellbore sizes, but for vertical gas Wells with smaller wellbore sizes, the influence of surface tension is more prominent, which causes changes in the liquid carrying state of the gas Wells. When the pipe diameter is small, the surface tension can even resist the influence of gravity under certain circumstances, so that the liquid is in equilibrium in the wellbore. Therefore, this model mainly considers the effect of the diameter of the wellbore on the critical liquid carrying velocity, and establishes a model for calculating the sufficient gas velocity required for all the liquid phase to be transported to the wellhead. He regarded the liquid film surface as a form of pipe wall roughness and a function of dimensionless liquid film thickness, which is one of the more commonly used correlation formulas.

In 1986, Barnea analyzed the influence trend of liquid film under different flow patterns and proposed two mechanisms for changing from annular flow to slug flow, among which the instability mechanism of liquid film was more reasonable.

In 1986, Zabaras[20] studied the stability criterion of liquid film for vertical tube annular flow, and believed that at high gas flow rate, liquid film moved upward with gas. In the case of low gas flow rate, the liquid film falls back, forming a liquid accumulation.

In 2003, Zhang[21] et al. analyzed the liquid film from the trend change of gas phase flow rate from small to large, and established the calculation method of critical gas flow rate.

In a 2008 study, Befroid concluded that the main reason for fluid accumulation in a well is whether the fluid film will backflow. The stability in the wellbore of a gas well mainly depends on the pressure drop and the mechanical balance on the liquid film. The oil and gas reservoirs with higher permeability have larger liquid supply, and the wellbore industry of low permeability oil and gas reservoirs is more sensitive. Through the software simulation, it is found that the critical liquid carrying velocity is related to well inclination Angle, flow state conversion and product, especially the influence of well inclination Angle on the critical liquid carrying velocity. The main factors of liquid film flow will change with different well inclination Angle. The critical flow rate is required to be the highest when the well inclination is around 40°. When the inclination Angle is lower than 40°, the thickness of liquid film under the wellbore will gradually increase with the increase of the inclination Angle, which leads to the difficulty of liquid lifting to the wellhead. When the well inclination exceeds 40°, the gravity of the film is offset by the supporting force of the pipe wall, resulting in a gradual decrease in the influence of gravity, which makes the fluid easier to lift. According to the liquid film model, the main cause of fluid accumulation is the backflow of the liquid film, which makes the liquid unable to be carried to the wellhead and flow back to the well.

In 2010, Veeken et al. analyzed the sensitivity of gas-injection liquid rate to different well parameters, adopted multiphase flow simulation software OLGA to simulate flow characteristics, compared the modeling results of steady-state and transient multiphase flow to identify the influence of the same well parameters, and concluded that the occurrence of liquid accumulation was due to liquid film inversion rather than droplet inversion. A modified Turner expression is proposed, which is more suitable to the field data, and can be used to predict the fluid accumulation in gas Wells by analyzing the friction factor of gas-liquid interface.

In 2013, Luo proposed a calculation model for non-uniform liquid film in inclined wellbore based on Barnea's work. Luo believes that under real circumstances, the liquid film of the inclined wellbore can not be evenly distributed, but is distributed in a "crescent" shape along the circumference of the wellbore wall. The liquid film is thinnest at the top and thickest at the bottom of the circumference, which can be approximated by sine function and the maximum thickness can be calculated. Luo believes that the maximum thickness is also related to the inclination Angle of the wellbore, when the inclination Angle is 60° (vertical is 90°), the liquid film reaches the thickest, and the empirical formula is used to express it. The maximum liquid film thickness under any liquid flow and inclination Angle can be obtained by combining the above sine formula and the empirical formula related to the inclination Angle. Luo believed that if the liquid film at the large thickness could be kept moving upward, then there would be no accumulation of liquid. Therefore, the maximum thickness was brought into the Barnea model, and the critical liquid carrying velocity of the non-uniform liquid film in the inclined wellbore could be calculated. The calculated results of Luo's model are in line with the change trend of critical liquid carrying velocity in inclined wellbore, but the basic assumption of Barnea's model is equal thickness model, which directly brings in the thickness of non-equal thickness liquid film, destroying the relationship between the basic equation established by Barnea. In addition, the experiments of Taitel(1980) and Taitel(1982) found that the liquid film with a larger thickness required a smaller liquid carrying speed, which was controversial with Luo's view. Therefore, Luo's non-equal thickness model still lacks some theoretical derivation support.

In 2014, Wu Dan's model mainly carried out optimization analysis on the above two types of models, and mainly analyzed all the forces exerted on the liquid film in the wellbore. Wu Dan believed that under the action of various forces on the liquid film in the wellbore, when its forces were balanced, the production state in the wellbore was critical liquid carrying state, and the calculation formula of Wu Dan's model was consistent with Pushkina's model. The main difference is that the value of Ku is corrected, Ku is 2.88.

In 2014, after summarizing published articles and comparing various experimental data of critical liquid carrying velocity, Li came up with a calculation method of critical liquid carrying velocity based on liquid membrane carrying theory. According to the experimental data of Guner(2012) and Alsaadi(2013), Li believed that Luo's empirical formula that the maximum thickness of liquid film changes with the inclination Angle is wrong, and the bottom liquid film thickness should reach the maximum value when the inclination Angle is 30° instead of 60°. On the basis of revising Luo model, Li used the empirical formula of friction coefficient of gas-liquid interface proposed by Andritsos(1987) to replace the method of calculating gas-liquid interface in Barnea model, and obtained a new calculation model.

In 2016, Chen Dechun et al. analyzed the force of liquid film and concluded that there was a balance between liquid film and gas core, as well as between liquid film and pipe wall. Based on the Turner model, the coefficient was modified and an Angle correction item was added to establish a new critical liquid carrying flow prediction model.

In 2017, Pushkina model mainly discovered and calculated the dimensionless parameter Ku to represent the balance relationship of various mechanics in the gas, so as to improve the accuracy of data simulation. Pushkina believes that Ku is a constant and its value is determined, and this model is mainly used in the critical state calculation process of vertical gas Wells.

In 2017, Wang compared the maximum liquid film thickness calculated by Luo and Li with the experimental data, and believed that the calculated value was too small, which led to the calculated value of the friction coefficient of the gas-liquid surface being too small, and thus the calculated value of the critical liquid carrying velocity being too large. Wang gave an empirical formula for calculating the maximum liquid film thickness based on experimental data, replaced the calculation method of the maximum liquid film thickness in the Luo, Li and other models, and improved the calculation method of gas density and the friction coefficient at the gas liquid boundary. Finally, a new calculation model was obtained. However, Wang's calculation model ignores the friction between liquid and tube wall, which is different from Barnea's strict formula derivation.

In 2017, Shekhar et al., based on the Luo model, refitted the empirical relationship to predict the liquid accumulation model with a wide range of dip angles from vertical to near-horizontal Wells, considering the influence of pipe diameter and dip Angle and combining with the influencing factors of liquid film thickness.

In 2018, Liu et al. established a governing equation for liquid film without considering the uneven distribution of liquid film caused by the gravity action of inclined tube. They correlated the critical gas flow rate model with the membrane flow rate, and established Navier-Stokes equation for liquid film to derive the correlation of critical gas velocity.

In 2019, Rastogi A et al. carried out a gas well wellbore fluid accumulation experiment, analyzed various influencing factors, and built a new model for various influencing factors from the perspective of mechanics.

In 2022, Wang Wujie et al. established a prediction model of critical liquid carrying velocity by using the principle of minimum energy, considered the influence of inclination Angle, and established a calculation model of phase interface friction factor. Compared with the inclined pipe, the liquid carrying mechanism of the straight pipe section is more complicated.

Regarding the liquid film inversion theory, some models take into account the influence of tubing diameter and inclination Angle, and there are many other factors that are not considered, such as viscosity, gas density, pressure gradient, actual gas flow rate, and the influence of gravity on the gas phase and liquid phase, which are all key factors affecting the fluid flow characteristics, and their models have certain limitations.

In short, in recent years, more and more experimental and theoretical studies believe that liquid film inversion is the main mechanism of gas well fluid accumulation. Belfroid et al. believe that liquid film inversion interacts with system instability and flow pattern transformation and occurs simultaneously, and regard liquid film inversion as the mechanism of fluid accumulation in gas Wells.

Veeken et al. used OLGA transient numerical simulation software and steady-state multiphase flow model to study gas well fluid accumulation. By comparing with the actual liquid accumulation gas well, it is found that the beginning of liquid accumulation in the gas well is consistent with the liquid film reversal, thus verifying that the liquid accumulation in the gas well is controlled by the liquid film reversal. Taking liquid film inversion as the starting point of gas well fluid accumulation, many scholars have carried out critical gas flow rate experiments to improve the understanding of gas well fluid accumulation. Guner et al., Alsaadi et al., Sarica et al., Kelkar et al., Wang et al., systematically carried out qualitative experimental studies on the effect of inclination Angle, pipe diameter and liquid volume on critical liquid carrying gas volume. Although these experiments only analyzed the variation law of critical liquid carrying gas flow rate from phenomena and test data, lacking in-depth theoretical analysis. However, it provides the experimental basis for the understanding of fluid accumulation in gas Wells and modeling based on liquid film inversion. Although there are many experiments based on liquid film inversion, there are few studies on the theoretical model of liquid film inversion. In vertical Wells, dimensionless airflow, which was first proposed by Wallis, can be used as a criterion for judging liquid film inversion, but this method is an empirical rule, and the model does not consider the influence of fluid volume and fluid properties on critical liquid carrying gas volume. At present, the most widely used model is the liquid film thickness model proposed by Barnea based on the Liquid Pan Research Institute, whose liquid film reversal point and critical gas flow rate can be determined according to the inflection point of the dimensionless shear curve calculated by different liquid film thicknesses. In horizontal Wells, the current theoretical studies are based on the assumption of uniform distribution of liquid film in the inclined pipe by force analysis to derive the critical liquid carrying gas. However, because the liquid film at the bottom of the inclined section is thicker and the liquid film flow and distribution are more complicated, this model has some defects. Therefore, Luo et al., from the University of Tulsa in the United States, based on Barnea's calculation method of liquid film thickness in vertical Wells and the experimental data of liquid film thickness distribution at different inclination angles of Paz and Shoham, proposed an empirical equation for calculating the maximum liquid film thickness at the bottom of pipe segments, thereby determining the critical liquid carrying gas volume of horizontal Wells at different inclination angles. Thereafter, Li et al., Shekhar et al., and Wang et al., based on the above, respectively considered the effects of Angle, internal shear force and liquid volume on liquid film thickness, and revised or re-fitted the empirical relation.

It is not difficult to find that there are relatively few research articles on liquid carrying in inclined wellbore gas Wells. Only in recent years have some research articles appeared. There are still some controversies in these studies on the principle of liquid carrying, liquid carrying phenomenon and calculation model, and the error of the prediction results of critical liquid carrying velocity is large.

4. A Review of Different Research Methods

The problem of liquid accumulation has a significant impact on the normal operation of gas-liquid two-phase flow pipelines and the efficiency of natural gas collection, especially in the case of complex terrain and large pipeline inclination. Droplet model and liquid film model are the two main methods to study the phenomenon of effusion.

The droplet model is mainly based on the force balance analysis of the droplet in the gas flow to predict and identify the liquid accumulation phenomenon in the gas well. The droplet model was first proposed by Turner et al., assuming that the droplet is spherical. By considering the force balance of the droplet in the gas core, a prediction model of the critical liquid carrying velocity was established. Subsequent studies have continuously optimized the model and considered the influence of droplet morphology under different flow conditions (such as Reynolds number changes). For example, the Li Min model considers the possibility that the droplet may be ellipsoidal, and considers the influence of factors such as pressure difference on the droplet shape and critical liquid carrying velocity. The Nosseir model uses different models according to different Reynolds numbers, and considers the influence of flow conditions on the droplet resistance coefficient. Wang Yizhong 's model proposes that the shape of the droplet is a spherical cap shape, and considers the influence of the shape on the drag coefficient, and increases the safety factor to improve the prediction accuracy. Based on the force analysis of a single droplet, the critical liquid carrying velocity in the inclined pipe is calculated by the Yang Wenming model, which further improves the accuracy and applicability of the model. These models try to predict and analyze the liquid loading phenomenon in gas wells according to different assumptions and parameters, but the challenges include that the simplified assumptions of the model may not fully reflect the actual complex flow conditions, especially in complex terrain and inclined pipelines.

The liquid film model focuses on the flow characteristics of the liquid film on the pipe wall, especially the influence of the possible reflux phenomenon of the liquid film on the liquid accumulation. The key lies in the stability and flow characteristics of the liquid film, which affect the occurrence of liquid accumulation in the pipeline. The liquid film model holds that the liquid accumulates when the liquid film flows downward, and predicts the location of the liquid accumulation point and the critical liquid carrying velocity. This model is suitable for describing the flow and change of liquid film along the pipe wall. By analyzing the stability and flow characteristics of liquid film under different flow states, researchers put forward different calculation methods and theoretical models to predict the movement of liquid film and its impact on the operation of the pipeline. Based on the theory of liquid film inversion, the Wallis model established a prediction model of liquid accumulation point, taking into account the influence of pipeline size on critical liquid carrying velocity. Zabaras model: The stability criteria of liquid film under different flow patterns are analyzed, and the calculation method of critical gas velocity is proposed. Luo model presents a calculation model of non-uniform liquid film for inclined wellbore, considering the distribution and influence of liquid film under different inclined angles. The Wu Dan model analyzes the conditions of liquid film force balance in wellbore, deduces the calculation formula of critical liquid carrying velocity, and compares it with the experimental data. Compared with the droplet model, the liquid film model pays more attention to the phenomenon of liquid film formed along the wall of the liquid in the pipeline, and its theoretical basis and calculation method can explain the problem of liquid accumulation under different flow conditions.

In summary, droplet model and liquid film model have their own research focus and application scenarios. These models can effectively predict and identify the problem of liquid accumulation in gas-liquid two-phase flow pipelines, providing important theoretical basis and technical support for pipeline design and operation. Future studies can further refine these models, especially their applicability and accuracy under complex operating conditions, to improve the efficiency and safety of pipeline operation.

5. Summary

1.Scholars at home and abroad have conducted detailed studies on the identification of liquid accumulation in gas Wells. On the whole, significant progress has been made since 1992. A systematic liquid accumulation identification system has been formed by the classic empirical formula method, pressure gradient method, oil sleeve pressure difference analysis method and other methods. As a result, the accuracy and precision of the judgment results are limited, especially in the prediction of the amount of fluid accumulation there is a large error. In addition, different liquid accumulation identification methods have different applicability to wellbore conditions. Some methods may be more effective for specific types of gas Wells, while others are not effective. It is necessary to choose the appropriate method according to the specific situation.

2. The liquid accumulation prediction model gradually proposed a more detailed model in the droplet model, such as considering the influence of droplet shape change on liquid carrying velocity, etc. Meanwhile, the accuracy of the theoretical model was gradually verified in the liquid film model through experiments and numerical simulation. However, the research on these models was not limited to vertical Wells, but also involved different types of Wells such as inclined Wells and horizontal Wells. Each model has its applicable scenarios and limitations. At present, the research on liquid carrying in inclined wellbore has not reached satisfactory goals, and more scholars need to further study, strive for a unified understanding, and obtain a more accurate calculation method of critical liquid carrying velocity.

3. Based on the above discussion, this paper proposes the following improvement methods to address the challenges faced by fluid accumulation prediction: First, to improve the accuracy and accuracy of identification and prediction, errors can be reduced by improving sensor technology, optimizing data analysis algorithms and other means to improve the accuracy of prediction. Secondly, the development of more intelligent fluid accumulation prediction technology is proposed to achieve more accurate fluid accumulation prediction and management through real-time data monitoring and machine learning algorithms. Finally, the accuracy and applicability of the fluid accumulation prediction method are further improved by in-depth verification and comparison in the actual production scenarios of different geological conditions and gas well types.

To sum up, although significant progress has been made in the research of fluid accumulation identification in gas Wells, it still faces challenges and opportunities such as accuracy improvement, intelligent development and practical application verification. In the future, attention should be paid to the application of technological innovation and comprehensive methods to achieve more accurate and reliable fluid accumulation identification and management.

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