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A Review of Prediction Methods for Permeability in Clastic Reservoirs

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Abstract: Accurate prediction of permeability in clastic reservoirs is of great significance for oil and gas exploration and development. This paper provides a comprehensive review of prediction methods for permeability in clastic reservoirs, including analytical methods, experimental testing, and numerical simulation. By comparing the three methods, it is found that the analytical method has the advantage of a theoretical basis and fast calculation speed, but the simplifying assumptions regarding reservoir structure may lead to inaccurate results. The experimental testing method directly measures the flow performance of rocks, but it is constrained by sample acquisition and experimental conditions. The numerical simulation method considers various influencing factors and simulates real reservoir conditions but requires extensive calculations and accurate parameter inputs. Future research can further develop the analytical method and numerical simulation method to improve prediction accuracy by incorporating actual data from experimental testing, leading to a more comprehensive and accurate prediction of permeability in clastic reservoirs.

Keywords: Clastic reservoirs, Permeability, Numerical simulation, Experimental testing, Analytical method.

1. Introduction

As one of the important reservoirs for oil and gas accumulation, clastic rock reservoirs have wide application value in oil and gas exploration and development. The flow capacity of a reservoir is an important indicator for assessing its oil and gas migration capability and production potential. Accurate prediction of the flow capacity of clastic rock reservoirs is of crucial significance for determining development plans, optimizing production efficiency, and resource evaluation. Therefore, research on prediction methods for the flow capacity of clastic rock reservoirs has received extensive attention from the academic community and the oil and gas industry. Over the past few decades, researchers have proposed various methods for predicting the flow capacity of clastic rock reservoirs. These methods can be classified into three categories: analytical methods, experimental testing methods, and numerical simulation methods. Analytical methods rely on rock physical parameters and flow theory to predict the flow capacity of the reservoir theoretically through mathematical modeling and analysis. Experimental testing methods directly determine the porosity, permeability, and flow capacity of rocks through laboratory tests and field observations, thereby inferring the flow capacity of the reservoir. Numerical simulation methods use computer simulation and numerical computation techniques to establish numerical models of the reservoir, predict the flow capacity of the reservoir by solving the flow equations and simulating physical processes. Although numerous studies have been conducted on prediction methods for the flow capacity of clastic rock reservoirs, each method has its own advantages and disadvantages. While analytical methods have the advantage of rapid computation, they may introduce certain errors when considering the complexity and nonlinearity of the reservoir. Experimental testing methods can directly measure the flow capacity, but they have limitations in sample acquisition and control of experimental conditions. Numerical simulation methods can simulate real reservoir conditions but require substantial computations and accurate input parameters. Therefore, this paper aims to provide a comprehensive review of prediction methods for the flow capacity of clastic rock reservoirs, summarizing the principles, advantages, disadvantages, and applicability ranges of various methods, to provide references and guidance for predicting the flow capacity of clastic rock reservoirs. Additionally, this paper will discuss the current issues with existing methods and propose future research directions and prospects, with the goal of further improving the accuracy and reliability of flow capacity prediction for clastic rock reservoirs and providing more feasible technical support for oil and gas exploration and development.

2. Research Progress on Prediction Methods for Flow Capacity of Clastic Rock Reservoirs

2.1. Experimental Testing Method

Currently, laboratory testing of fracture flow capacity is primarily based on Darcy's law. Various testing devices, such as FCS-842 and FCES-100, developed in accordance with API testing standards, are used for testing. These devices can simulate the actual conditions of fractures in the formation, including pressure and temperature, and conduct flow capacity tests. The differences lie in the variation of flow capacity obtained by changing the material of the simulated fracture wall, experimental medium, sanding method, and other factors influencing flow capacity.

Jin Zhirong et al. investigated the factors influencing the flow capacity of supported fractures using the FCES-100 fracture flowmeter. Wang Lei et al. conducted indoor flow capacity tests on sandstone slabs using the FCES-100 flowmeter to study the support patterns and flow capacity of fractures in high-speed channels. Cao Kexue et al. measured the crushing rate and flow capacity of ceramic beads and quartz sand used in the field of Changqing using the FCES-100 fracture flowmeter based on the recommended method in SY/T6302-2009. Jiang Jianfang et al. compared the difference in flow capacity measurements between liquid and gas using the API flowmeter and proposed conducting gas flow capacity studies for gas reservoir development. Chen Qingdong et al. conducted experiments to determine the porosity and flow capacity of proppants under different closure pressures using porosity measurement equipment and API standard flow capacity measurement devices. In 2014, Qu Zhanqing et al. used the same instruments and standards to measure the flow capacity of typical proppant types and particle size combinations in a field hydraulic fracturing operation, and used gray correlation analysis to determine the degree of influence of various factors on flow capacity.

Wen Qingzhi et al. studied the influence of factors such as closure pressure, proppant concentration, sand dam height, proppants, and fracture network structure on fracture network flow capacity using a new flow chamber connected to the FCES-100 fracture flowmeter, which was independently designed. Li Shibin et al. split cylindrical specimens with dimensions of 50mmx100mm to obtain rough fracture surfaces. The rough fracture surfaces were then displaced by a certain amount, and the shear-slipped non-matching fracture surfaces were prepared by grinding the displaced core end faces flat. The flow capacity of these surfaces was then tested in a flow chamber.

Zhao Yadong conducted flow capacity tests using deionized water and rock slabs with the FCS-842 fracture flow capacity testing system developed by TEMCO, USA. Zhao Yabing et al. also used the FCS-842 fracture flow capacity testing system and conducted a comprehensive study on factors affecting flow capacity using rock slabs machined from full-diameter cores under reservoir conditions, and established an empirical formula.

2.2. Analytical Method

Currently, the calculation models for fracture flow capacity obtained using the analytical method are mostly based on the well-known semi-empirical Carman-Kozeny equation in the field of porous media. These models are derived by considering the actual state of proppants in the fracture. Some researchers have also developed fracture flow capacity models based on compression theory, solid contact theory, rock mechanics, and other theoretical models.

Gao Changlong et al. established a fracture flow capacity calculation model considering proppant crushing based on the Carman-Kozeny equation. Building upon this, Gao Changlong combined the vertical displacement calculation formula in elastic mechanics, Hertzian elastic contact theory, and established a fracture flow capacity calculation model that considers the influences of formation elastic modulus and Poisson's ratio, formation closure pressure, proppant size, and proppant elastic modulus and Poisson's ratio.

In 2016, Awoleke et al. developed a mathematical model considering reservoir temperature, closure pressure, proppant fracturing stress, and proppant concentration based on dimensional analysis and a semi-empirical model.

In 2017, Yan Xiangyang et al. established a calculation model for flow capacity of sandstone reservoirs without proppant, considering the characteristics of closed unfilled fractures, combining the Carman-Kozeny equation and the Walsh model. Based on this, they further developed a flow capacity calculation model for unfilled hydraulic fractures considering particle support and particle-particle crushing.

Li Haitao et al. derived a flow capacity calculation formula, considering factors such as proppant arrangement and embedded deformation, based on experiments and the Carman-Kozeny equation, which includes fracture width, formation porosity, and permeability changes.

In 2019, Zhu Weiyao et al. established a flow capacity calculation model for fractures, considering factors such as proppant concentration, closure pressure, proppant size, proppant material, and proppant embedding, based on the densest arrangement of proppants and the Carman-Kozeny equation, combined with knowledge from elastic mechanics.

Chen Dong et al. developed a fracture flow capacity calculation model considering the dual effects of compaction and embedding on fracture flow capacity. This model is based on the theory of pore compression and solid contact, taking into account the effects of compaction and embedding.

$$\theta=\frac{C}{C_0}=\frac{kw}{k_0 w_0}=\left(1-\frac{\eta\sigma_e^{\lambda}}{w_0}\right)e^{-3\overline{C_P}(\sigma_e-\sigma_{e0})} \qquad (1)$$

Fang Shi et al. established a coupled numerical model considering the transport, placement, deformation, embedding, and fracturing of proppant within the framework of eXtended Finite Element Method (XFEM).

Cao Haitao analyzed the variation of fracture conductivity using fractal theory. The flow channels within the fracture were assumed to be a series of capillary bundles with fractal characteristics. Based on this, a predictive model for fracture conductivity under different closure stresses was developed, and the results were validated using percolation theory combined with physical models.

Jiao Hongyan integrated multiple disciplines such as rock mechanics, elastoplastic mechanics, material mechanics, contact mechanics, and geometry to establish a predictive model system for fracture conductivity considering dynamic changes in proppant embedding, deformation, and fracturing.

2.3. Numerical simulation method

In 2015, Dou Xiangji et al. proposed a method to determine the dynamic fracture conductivity using a segmented history matching approach combined with numerical simulation and pressure buildup tests.

In 2017, Su Yubin, Lin Guanyu, and others predicted the fracture conductivity of tight sandstone reservoirs in Block An 83 of Changqing Oilfield using the Meyer software. The results indicated that ceramic proppants had higher conductivity compared to quartz sand and resin-coated sand. Moreover, larger proppant size and higher proppant concentration resulted in higher fracture conductivity at low closure pressure.

Kou Shuangfeng, Chen Shaoning, and others used numerical simulation methods to predict the artificial fracture conductivity required for the Sulige tight sandstone gas reservoir. They employed the Eclipse reservoir simulation software to establish a single-well numerical model using a block-centered grid, and enhanced grid refinement around the hydraulic fracture.

In 2018, Zhu Haiyan et al. developed a numerical simulation model for fracture conductivity of propped fractures based on the flow-solid coupling between proppant cluster void fluid and proppant. The model considered the effects of fracture closure stress, reservoir elastic modulus, proppant concentration, and proppant arrangement on fracture conductivity.

2.4. Proppant embedding analysis

There are various factors that affect the conductivity of supporting fractures, among which the embedding of proppants is an important factor that leads to a decrease in the conductivity of supporting fractures. The embedding process of proppant is the deformation process of formation rocks. Under the action of crack closure pressure, supporting particles in direct contact with the crack wall will embed into the formation, resulting in a decrease in the effective width of the crack, a decrease in porosity and permeability within the crack, and a loss of fracture conductivity.

McGlothlin, Lacy, and Lu et al. conducted research on the embedding of proppants. The experimental results indicate that closure pressure, sand concentration, and formation properties are important factors affecting the embedding of proppants. High pressure, low sand concentration, or soft formations can lead to an increase in the embedding amount. In order to investigate the impact of proppant embedding on fracture conductivity, it is necessary to. Wen Qingzhi et al. used the FCES-100 fracture conductivity meter to study the damage of factors such as closure pressure and time on the fracture conductivity of proppant embedded in the core. Guo Tiankui et al. conducted a large number of experimental studies on the embedding of proppants in formation cores using the FCES-100 fracture conductivity instrument. By comparing the conductivity, they comprehensively investigated the embedding degree of different types, sand laying concentrations, particle sizes, and conventional performance of ceramic proppants under different core and closure pressure conditions. Sun Haicheng, Xu Yun and others made a detailed study on the damage of proppant embedding to fracture width, permeability and conductivity by using the proppant long-term conductivity test device formed on the basis of API linear conductivity device.

Guo Jianchun and others developed a set of proppant embedding degree testing and analysis system based on API standard diversion chamber, and conducted experimental research on the embedding degree of proppant in formation rock cores. They investigated the embedding situation of proppant in different rock cores under different sand concentration and stress.

In addition, there are some empirical or semi empirical formulas summarized through experiments for calculating the embedding of proppants. Volk et al. summarized empirical formulas considering particle size, sand concentration, proppant distribution, and rock properties based on experimental results.

$$W=D\left[1-B\left(P_e/nD^2\right)^m\right]^{1/2} \tag{2}$$

Li Yongming et al. established a quantitative calculation model for the embedding depth of proppants by analyzing the forces acting on them through microelements, taking into account the closure pressure, proppant particle size, rock Young's modulus, and microelement deformation elasticity

Li Chao et al. analyzed the influence of proppant embedding factors on proppant fracture conductivity by using self-made conductivity test instrument and proppant embedding test device, and deduced the calculation formula of proppant fracture conductivity considering proppant embedding.

According to the Carman Kozeny formula, Wu Guotao et al. established a numerical calculation model for the conductivity of supporting cracks considering the embedding of proppants on the rock surface. The model was modified using experimental data and a correction factor was introduced α， A more accurate calculation model is provided for calculating the fracture conductivity under the condition of considering the embedding of proppants.

Gao et al. established a calculation model for conductivity under closed pressure conditions, ignoring proppant fragmentation and considering proppant embedding, deformation, and crack deformation.

3. Existing Problems

(1) The experimental detection method is based on Darcy permeability and tests the fracture conductivity using API or self-made flow chambers. It can simulate the pressure of proppant in actual fractures to a certain extent, but there are few simulation testing equipment for formation temperature. For situations where there are few models for predicting long-term conductivity, experimental equipment can be used for testing. However, using laboratory testing methods to measure conductivity has a long testing cycle and high cost.

(2) The calculation model of fracture conductivity derived from the analytical method is mostly based on the Carman Kozeny formula, the most famous semi empirical formula in the field of Porous medium, and the formula obtained under the actual conditions of proppant embedding, deformation, compression, etc. There are also fracture conductivity models based on Compressibility theory, solid contact theory, Rock mechanics and other theoretical models. The diversion capacity calculation models derived based on empirical or semi empirical formulas are all derived under specific conditions and are limited in general applications. The calculation model obtained based on multiple theories overlooks many factors during the establishment process, is too idealized, and the mathematical model solving process is complex.

(3) The numerical simulation method establishes fracture models on Commercial software such as Eclipse and Mayer, and simulates the fracture conductivity, which is widely used and low cost. However, numerical simulation requires a large amount of computation and is slow in calculation speed, resulting in low accuracy in describing the morphological properties of fracturing fractures and proppants.

4. Outlook

Based on the current research status of fracture conductivity prediction, the following suggestions are proposed:

(1) In view of the problems of supporting complex fracture network formed by large-scale volume fracturing of dense

Clastic rock, such as low sand paving concentration, effective supporting fracture length, etc., the research on proppant embedding and fracturing on long-term conductivity of fractures should be increased, and the corresponding theoretical model of real mechanics of composite proppant particles should be established.

(2) After the exploitation of tight Clastic rock gas reservoir, complex fracture network is the main gas and water seepage channel. Gas and water co exploitation, high-speed seepage, formation water dissolution Diagenesis, etc. all exist for a long time and affect the conductivity. Therefore, the research on multiphase seepage, non Darcy seepage, formation water and other influencing factors should be continued.

(3) Due to the long period and high cost of long-term conductivity Achievement test of propped fractures, it is recommended to carry out research on long-term conductivity prediction model and establish a prediction model of Clastic rock conductivity under the influence of multiple factors and the real force of proppant.

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