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Study on sulfur deposition damage model of fractured gas reservoirs with high-content H_2S

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A B S T R A C T

Due to extreme poison, strong corrosion, and complex precipitation and deposition of H_2S in the reservoir, it is very difficult and risky to investigate and explore drilling, completion, production and gas transportation. In the course of production of fractured gas reservoir with high H_2S content, formation pressure falls continually, which lead to decline of solubility of sulfur particles in gas phase. Sulfur particles which dissolve in gas phase originally in the formation should precipitate from gas phase after running up to saturation state and deposit at pore space and throat, sequentially resulting in formation porosity and permeability reduction. At present, the researches of sulfur deposition are mainly focused on the conventional gas reservoirs and sulfur deposition in the near wellbore region is generally estimated using Roberts' model. However, most of the gas reservoirs with high-content H_2S are fractured gas reservoirs, classical damage model is no longer applicable to fractured gas reservoirs with high H_2S content. In the present study, a sulfur deposition damage model is established. The refined model, based on non-Darcy flow, takes into consideration the effects of sulfur deposition, variation in gas properties and fracture. In addition, the effect of gas well production rate on formation permeability is also studied. The results show that formation permeability decreases with fracture aperture and gas well production rate increasing. The bigger gas well production rate is, the quicker sulfur precipitates. The sulfur deposition of fractured gas reservoir with high-content H_2S is mainly in the near wellbore zone, and the fracture aperture has a significant impact on the formation permeability in the near wellbore zone.

1. Introduction

Fractured gas reservoirs with high-content H_2S are an unconventional type of reservoirs and widely distributed in the world, many of the high sulfur gas reservoirs have been found in the northeast of Sichuan, China [1–4]. Technical studies, production and operations, and management of this type of gas reservoirs with high H_2S content are difficult and uneconomical tasks to perform due to high toxicity and corrosion of H_2S. Sulfur precipitation is an important phenomenon during high-content H_2S gas production. In the course of production of fractured gas reservoir with high H_2S content, formation pressure falls continually, which lead to decline of solubility of sulfur particles in gas phase. Sulfur particles which dissolve in gas phase originally in the formation should precipitate from gas phase after running up to saturation state and deposit at pore space and throat, sequentially resulting in formation porosity and permeability reduction. On the other hand, fracture will close continually due to decrease of formation pressure, which will also result in descending of porosity and permeability. Gas well production may halts when sulfur deposition and fracture close become severe.

A large number of researches concentrated on sulfur deposition, especially of gas reservoirs, have been carried out and a lot of recognition of problems due to sulfur deposition associated with the production of sour gas has been achieved. Sulfur precipitation can impair well productivity and the economics of

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reserve depletion [5,6]. Kuo and Colsmann [7] developed the first mathematical model of a solid phase precipitation in porous medium and its influence on fluid flow. Roberts [8] built the empirical formula of the solubility of sulfur in acidic natural gas according to the solubility model proposed by Chrastil [9] and the experimental data of Brunner and Woll [10,11]. Porosity damage was introduced into Roberts' model by Fadairo et al. [12] in 2012. Further enhancements to Roberts' model were introduced by Mahmoud and Al-Majed where a deviation factor, gas volume factor, and viscosity were addressed as a function of pressure [13]. Hands et al. [14] researched the effect of natural fracture to sulfur deposition and Hu et al. [15] developed a mathematical model of sulfur deposition damage in the presence of natural fracture, but the model did not demonstrate the effect of fracture on the formation permeability.

In contrast to previous studies, a new mathematical model of formation damage for fractured gas reservoir with high H_2S content, accounting for sulfur deposition, fracture, and variation in gas properties (Z factor and viscosity), was presented relative to characteristics of complex flow in fractured gas reservoir with high H_2S content. The effects of parameters such as fracture aperture, radial distance, contact area and gas well production rate on reservoir permeability were investigated.

2. Mathematical model

2.1. Model assumptions

To simple mathematical model and to be convenient to solve it, the following assumptions were made:

(1) The reservoir is level, equal thickness, and homogeneous.
(2) The temperature remains constant in the formation.
(3) Sulfur is saturated in the gas phase in the formation.
(4) Precipitated elemental sulfur in-situ deposit.
(5) Precipitated elemental sulfur is a solid particle.
(6) Water phase is not considered.

2.2. Prediction model of sulfur solubility

Sulfur solubility prediction model is essential for sulfur precipitation. Experimental determination of the solubility of sulfur for a specific reservoir fluid is generally time consuming and costly. As a result, a predictive technique for estimating sulfur solubility in sour gas is desirable. For instance, several equation-of-state (EOS) based thermodynamic models have been developed for prediction of sulfur solubility in sour gas. However, these equations of state required a large amount of experimental data to establish model parameters. A simple correlation which was developed by Chrastil for predicting the solubility of solids in a high pressure fluid was used to evaluate the desired solubility–pressure relationships:

$$C = \rho^k \exp(M/T + N) \tag{1}$$

where C is the solubility of the solid-phase sulfur, g/cm^3; ρ is the fluid density kg/m^3; T is temperature, K; k, M, and N are empirical constants estimated from experimental measurement.

Sulfur solubility data for sour gas mixtures reported by Brunner and Woll could be used to estimate the correlation parameters. Combined with the Brunner and Woll's experimental data, the following correlation expression is used to predict the solubility of sulfur for a specific reservoir fluid under the condition of reservoir.

$$C = \rho^4 \exp(-4666/T - 4.5711) \tag{2}$$

The solubility of sulfur in sour gas in specific reservoir is mainly controlled by pressure and temperature. Generally speaking, gas flow in porous media in the formation is considered as an isothermal process. Therefore, the reservoir pressure is the major factor controlling sulfur deposition in pay zones.

The fluid density in Eq. (2) can be calculated as:

$$\rho = M_a \gamma_g p / ZRT \tag{3}$$

Differentiating Eq. (2) with respect to pressure we get [16]:

$$\frac{dC}{dp} = 4\left(\frac{M_a \gamma_g}{ZRT}\right)^4 \exp(-4666/T - 4.5711)p^3 \tag{4}$$

In Eq. (4), dC/dp is a cubic function of pressure and changes dramatically in the zone near wellbore.

Where M_a is air molecular weight, 28.97; γ_g is gas relative density; R is general gas constant; T is the formation temperature, K; Z is the gas Z-factor; p is gas reservoir pressure, MPa.

2.3. Prediction model of sulfur saturation

For the fractured gas reservoirs, the general gas flows from the matrix to the fractures, and then flows to the bottom of the well. Cubic law, based on the analogy of flow between parallel plates, is the most commonly accepted equation for gas flowing through fracture:

$$q = -\frac{\varepsilon^3}{12\mu}\left(\frac{dp}{dx}\right) \tag{5}$$

The arguments against the use of the parallel plate model are that it ignores the pressure losses resulting from turbulence, the existence of surface contact between the fracture surfaces, the waviness or tortuosity of the fracture network and roughness or variability of natural fractures.

The cubic law (Eq. (5)) is obtained assuming laminar flow. However, non-linear flow may occur when inertial losses are taken into consideration. Inertial losses are arising from entrance and exit losses along fracture boundaries, changes in flow velocity or direction along the flow path due to constrictions or obstructions, and initiation of turbulence due to localized eddy formation.

For the fractured gas reservoir with high-content H_2S, the fracture is the main flow channel. The non-linear flow, caused by the change of fluid velocity, flow direction, vortex, and other factors, are taken into account. Eq. (5) is rewritten as:

$$-\frac{dp}{dr} = a_c v + b_c v^2 \tag{6}$$

where v is velocity of flow, m/s; a_c is linear coefficient; b_c is non-linear coefficient; r is the radial distance, m; p is gas reservoir pressure, MPa.

When the dimensionless method is applied, Eq. (6) is rewritten as:

$$\frac{dp}{dr} = a_D \frac{\mu}{\varepsilon^2} v + b_D \frac{\rho}{\varepsilon} v^2 \tag{7}$$

where a_D is dimensionless linear flow coefficient; b_D is dimensionless nonlinear flow coefficient; p is gas reservoir pressure, MPa; ε is the fracture aperture, μm; ρ is gas density, kg/m^3; r is the radial distance, m; μ is the fluid viscosity, mPa s.