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Research Article

Study on Skin Factor and Productivity of Horizontal Well after Acidizing with Nonuniform Damage

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Horizontal well (HW) was divided into several elements after acidizing. In each element, there would exist a composite zone that was made up of damage zone (DZ) and acidizing zone (AZ). Local skin factor after acidizing was used to describe the resistance in each composite zone. The models for local skin factor and productivity of HW were created using the method of equivalent filtration resistance and displacement between two similar flow modes. According to the solution of the models, type curves of skin factor and production-increasing ratio after acidizing were illustrated, and the effect of different parameters in DZ and AZ on distribution of skin factor and production-increasing ratio after acidizing were discussed. The present model has a significant guide on the practice of acidizing technology.

1. Introduction

Numerous researchers have modeled the skin factor and productivity of horizontal well (HW) by different methods and, furthermore, the flow in the wellbore has also been considered.

Frick and Economides [1] presented a mathematical model of skin factor for a HW. In their model, the anisotropy of the permeability and the shape of a truncated elliptical cone in damage zone (DZ), with the larger DZ near the vertical section of HW, were taken into account.

For anisotropic medium, Permadi et al. [2–5] pointed that the shape of damage region was circular near the well and elliptical far from the well and presented a new analytical model for damage skin factor and the resulting reservoir inflow for a horizontal well, which can be more accurate than previous model for skin factor and productivity of HW.

Parn-anurak and Engler [6] put forward a new model to describe the distribution of the skin factor along the wellbore of a HW, in which the DZ had a cylindrical-conical shape; meanwhile, the penetration rate, the length of HW, and the anisotropy ratio were taken into account.

Ye et al. [7] proposed a method for evaluating formation damage from a drilled HW. Their model could calculate the invasion depth of drilling fluid and completion fluid, which also simultaneously considered the skin factor, flow efficiency of the well, and production loss in order to predict the extent of damage to the formation.

Cai et al. [8, 9] proposed analytical fractal model to analyze the depth of extraneous fluid invasion, where the tortuosity of capillaries and wettability effect [10] are taken into account. Their models show that the impregnation depth follows a scaling law of time where the exponent is a function of fractal tortuosity dimension rather than the classical constant 0.5. Except for the methods that are mentioned above, the fractal theory could also be used in the study on skin factor for HW [11–13].

Yildiz et al. [14, 15] considered the problem of steady filtration flow of an incompressible single-phase fluid near the HW with varying permeability in DZ. In this model, the effect of damage ratio, the size and shape of DZ, and the geometric parameters of the permeability profile on productivity of HW were investigated. Based on the research, the effect of varying permeability in the DZ could also be taken into account on skin factor and productivity of HW [16].

Taking into account a negative skin, Nie et al. [17] considered a set of complex boundary conditions and built a comprehensive semianalytical model for a HW in homogeneous

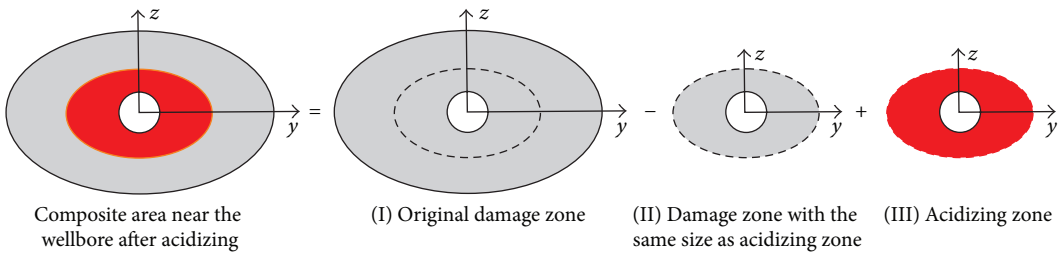

Figure 1: Division of elliptic composite zone.

or dual- or triple-porosity reservoir, which performed well against the real field data.

An and Wu [18] built a semianalytical model for predicting production rate of complex wells in anisotropic reservoirs considering damage to the formation due to the invasion of drilling and well completion, which were expressed by a skin factor. Their model could fully take into account the characteristics of formation damage and its impact on productivity of HW.

The methods mentioned above had discussed the establishment, solution, and applications in actual production process of models of skin factor for HW in detail; however, the models can be just for the HW with no stimulation treatment, while in most cases, a suitable acid would be used to remove the formation damage [19, 20], so a new model of skin factor for HW after acidizing will be more suitable to actual production conditions. In this paper, DZ distributing nonuniformly along the wellbore after being treated by acid is simulated using a series of elliptic composite areas, which can be the most appropriate approach for actual shape of DZ after acidizing. Meanwhile, the flows in porous media and wellbore are coupled to calculate the productivity of HW after acidizing. A comprehensive model is then presented by introducing the nonuniform DZ to calculate the skin factor and productivity of HW after acidizing. Factors influencing the distribution of skin factor and productivity of HW after acidizing are analyzed. The model can provide a new solution to calculate the skin factor and productivity of HW after acidizing in empirical application.

2. Coupling Model between Reservoir and Wellbore

2.1. Flow Model in the Reservoir. When the HW is treated by acidizing, the DZ near the wellbore will be improved, which leads to the decrease of skin factor, while the zone far from the wellbore is the same as that before acidizing, so the study on HW after acidizing will be focused on the flow characteristic near the wellbore. In anisotropic reservoir, due to the permeability difference between horizontal plane and vertical plane, at any location along the horizontal section, near the wellbore, there exists an elliptic DZ; moreover, when the HW is treated by acidizing, the isopiestic lines near the wellbore are still a cluster of concentric elliptical arcs [21]; that is to say, after acidizing, near the horizontal wellbore, there will be a composite zone at any location along the horizontal section, but due to the nonuniform distribution of radius of DZ and acidizing zone (AZ), we should use an infinitesimal method to get the local skin factor of HW after acidizing, eventually obtaining the total skin factor.

2.1.1. Model for Local Skin Factor. In order to study the local skin factor of HW, firstly we should select an infinitesimal section at any location along the horizontal section, as is shown in Figure 1, so it can be considered as a point sink in elliptic composite zone, but there is no accurate method to solve this problem so far, so we can divide the elliptic composite zone into combination of three homogeneous zones and then solve the filtration problem in every homogeneous zone, respectively, and finally use the superposition theorem to solve the filtration problem in composite zone.

Section I in Figure 1 is the original DZ near the wellbore; in this section, we can consider it as a vertical well in the elliptic supply boundary, so its seepage differential equation and boundary conditions can be described as follows, respectively:

$$\begin{gathered}\frac{\partial^2\Phi(x)}{\partial^2 y}+\frac{\partial^2\Phi(x)}{\partial^2 z}=0;\\ \frac{y^2}{d_h^2(x)}+\frac{z^2}{d_v^2(x)}=1,\qquad \Phi(x)=\Phi_d(x);\\ \oint\frac{\partial\Phi(x)}{\partial n}ds=dq(x),\end{gathered}\tag{1}$$

where Φ_d is potential in the DZ's boundary, d_h is horizontal radius of DZ, d_v is vertical radius of DZ, and q is the production of HW.

The solution of the problem as (1) shows is very difficult; there is no analytical solution so far, but approximate solution can be used, namely, the method of displacement between two similar flow modes [22]; that is to say, we can consider the filtration problem of a point sink in elliptic supply boundary as that between two paralleled isopiestic lines, which have a distance of $2H(x)$, as Figure 2 illustrates.

Its seepage differential equation and boundary conditions can be turned into

$$\begin{gathered}\frac{\partial^2\Phi(x)}{\partial^2 y}+\frac{\partial^2\Phi(x)}{\partial^2 z}=0;\\ z=\pm H(x),\qquad \Phi(x)=\Phi_1(x);\\ \oint\frac{\partial\Phi(x)}{\partial n}ds=dq(x),\end{gathered}\tag{2}$$

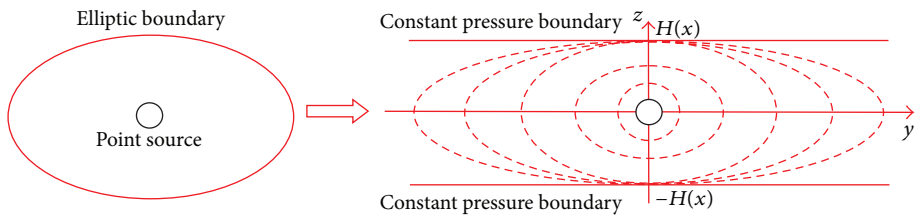

Figure 2: Method of displacement between two similar flow modes.

where Φ_1 is potential in constant pressure boundary and $2H(x)$ is the distance between two constant pressure lines.

Using the potential superposition principles, the analytical solution of (2) can be got as follows [23]:

$$\Phi(x) = \frac{0.92dq(x)}{dx} \ln \frac{\mathrm{ch}(\pi y/2H(x)) - \cos(\pi z/2H(x))}{\mathrm{ch}(\pi y/2H(x)) + \cos(\pi z/2H(x))} + \Phi_1(x). \tag{3}$$

Equation (3) is deduced based on the SI system of basic unit in oil reservoir; we can improve it into SI system of mine unit in gas reservoir, so (4) shows the distribution of potential near a point sink in the elliptic supply boundary:

$$p^2(x) = \frac{1.291 \times 10^{-3} dq_{sc}(x) \cdot T\mu_g Z}{2K_{dv} \cdot dx} \times \ln \frac{\mathrm{ch}(\pi y/2H(x)) - \cos(\pi z/2H(x))}{\mathrm{ch}(\pi y/2H(x)) + \cos(\pi z/2H(x))} + p_1^2(x), \tag{4}$$

where q_{sc} is the production of horizontal gas well, T is the gas reservoir temperature, μ_g is the gas viscosity, Z is the gas deviation factor, and K_{dv} is the vertical permeability of DZ.

Because points $[d_h(x), 0]$ and $[0, d_v(x)]$ are in the same isopotential line, substituting the plane of the two points into (4), respectively,

$$p_d^2(x) = \frac{1.291 \times 10^{-3} dq_{sc}(x) T\mu_g Z}{2K_{dv} \cdot dx} \times \ln \frac{\mathrm{ch}(\pi d_h(x)/2H(x)) - 1}{\mathrm{ch}(\pi d_h(x)/2H(x)) + 1} + p_1^2(x), \tag{5}$$

$$p_d^2(x) = \frac{1.291 \times 10^{-3} dq_{sc}(x) T\mu_g Z}{2K_{dv} \cdot dx} \times \ln \frac{1 - \cos(\pi d_v(x)/2H(x))}{1 + \cos(\pi d_v(x)/2H(x))} + p_1^2(x), \tag{6}$$

where p_d is the pressure of DZ's boundary.

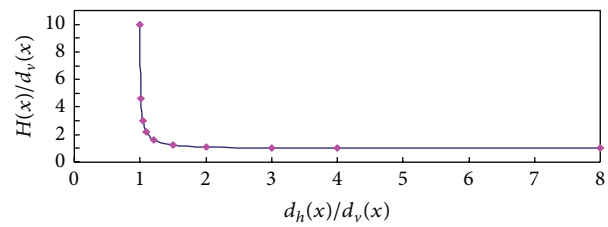

Figure 3: Relationship curve between $H(x)/d_v(x)$ and $d_h(x)/d_v(x)$.

Coupling (5) and (6),

$$p_1^2(x) = p_d^2(x) - \frac{1.291 \times 10^{-3} dq_{sc}(x) \cdot T\mu_g Z}{K_{dv} \cdot dx} \ln\left(\tan \frac{\pi d_v(x)}{4H(x)}\right) \tag{7}$$

$$\tan \frac{\pi d_v(x)}{4H(x)} = \mathrm{th} \frac{\pi d_h(x)}{4H(x)}. \tag{8}$$

Due to the reason that, through (8), we cannot get the analytical solution of $H(x)$, we can study its change rule by graphing method; Figure 3 is the relationship curve between $H(x)/d_v(x)$ and $d_h(x)/d_v(x)$.

From Figure 3, it is interesting to find that when the value of $d_h(x)/d_v(x)$ is more than 1.5, the value of $H(x)/d_v(x)$ will tend to 1, due to the effect of permeability anisotropy; the value of $d_h(x)/d_v(x)$ is always more than 1.5, so in this paper, we can make an assumption that $H(x)$ is similar to $d_v(x)$.

Substituting (7) into (4),

$$p^2(x) = p_d^2(x) + \frac{1.291 \times 10^{-3} dq_{sc}(x) \cdot T\mu_g Z}{4K_{dv} \cdot dx} \times \ln \frac{\mathrm{ch}(\pi y/2H(x)) - \cos(\pi z/2H(x))}{\mathrm{ch}(\pi y/2H(x)) + \cos(\pi z/2H(x))}. \tag{9}$$

Because the isopiestic line near the wellbore is circular, we can take any point $(0, r_w)$. At this point, the pressure is $p_{wf}(x)$:

$$p_{wf}^2(x) = p_d^2(x) + \frac{1.291 \times 10^{-3} dq_{sc}(x) \cdot T\mu_g Z}{K_{dv} \cdot dx} \times \ln\left(\tan \frac{\pi r_w}{4H(x)}\right), \tag{10}$$

where $p_{wf}(x)$ is pressure at any location along the wellbore and r_w is the wellbore radius.

Equation (10) can be transformed as

$$\Delta p_d^2(x) = p_d^2(x) - p_{wf}^2(x) = \frac{1.291 \times 10^{-3} dq_{sc}(x) \cdot T\mu_g Z}{K_{dv} \cdot dx} \ln\left(\cot\frac{\pi r_w}{4H(x)}\right). \quad (11)$$

According to the formula of vertical well's skin factor [23],

$$\Delta p_s^2 = \frac{1.291 \times 10^{-3} \cdot q_{sc} T\mu_g Z}{K_h h} S, \quad (12)$$

where K_h is the permeability of formation, h is the gas reservoir thickness, and S is the skin factor of vertical well.

We can make an assumption that the anisotropy before and after acidizing is constant; namely, $\beta = (Kh/K_v)^{1/2} = (K_{dh}/K_{dv})^{1/2} = (K_{ah}/K_{av})^{1/2}$; comparing (11) with (12), the skin factor of section I can be written as follows:

$$S_1(x) = \left(\frac{K_h}{K_{dh}} - 1\right) \ln\left[\cot\frac{\pi r_w}{4d_v(x)}\right]. \quad (13)$$

Identical method can be used to get the skin factor of sections II and III; namely,

$$S_2(x) = \left(\frac{K_h}{K_{dh}} - 1\right) \ln\left[\cot\frac{\pi r_w}{4a_v(x)}\right],$$
$$S_3(x) = \left(\frac{K_h}{K_{ah}} - 1\right) \ln\left[\cot\frac{\pi r_w}{4a_v(x)}\right], \quad (14)$$

where K_{dh} is the horizontal permeability of DZ, K_{ah} is the horizontal permeability of AZ, and a_v is the vertical radius of AZ.

So the local skin factor of HW along the wellbore after acidizing will be written as follows:

$$S(x) = S_1(x) - S_2(x) + S_3(x) = \left(\frac{K_h}{K_{dh}} - 1\right) \ln\left[\frac{\cot(\pi r_w/4d_v(x))}{\cot(\pi r_w/4a_v(x))}\right] + \left(\frac{K_h}{K_{ah}} - 1\right) \ln\left[\cot\frac{\pi r_w}{4a_v(x)}\right]. \quad (15)$$

If we want to calculate the distribution of local skin factor of HW after acidizing, the formula about vertical radius of DZ and AZ must be known. During drilling and acidizing, the heel has the maximum radius of DZ and AZ with the reason of longest time exposing to fluid, namely, $d_{v.\max}$ and $a_{v.\max}$, while the toe has the least time exposing to fluid, so we consider it as minimum damage, namely $d_{v.\min}$ and $a_{v.\min}$. Based on the Frick-Economides' research on skin factor of HW, we can make an assumption that the vertical radius of DZ and AZ decreases linearly from heel to toe along the wellbore, as Figure 4 illustrates.

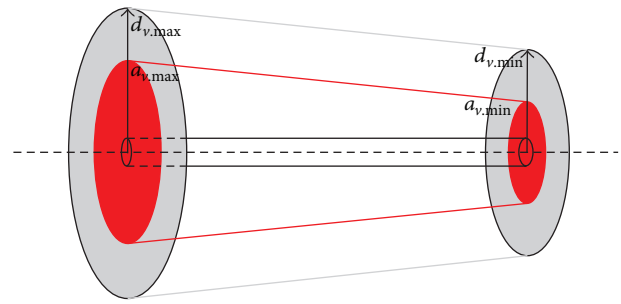

Figure 4: Distribution of DZ and AZ along the wellbore.

So the formula of radius of DZ, $d_v(x)$, and AZ, $a_v(x)$, can be written:

$$d_v(x) = \frac{d_{v.\max} - d_{v.\min}}{L}(L - x) + r_w + d_{v.\min},$$
$$a_v(x) = \frac{a_{v.\max} - a_{v.\min}}{L}(L - x) + r_w + a_{v.\min}, \quad (16)$$

where $d_{v.\max}$ is the vertical maximum distance of mud immersion, $d_{v.\min}$ is the vertical minimum distance of mud immersion, $a_{v.\max}$ is the vertical maximum distance of acid-rock reaction, $a_{v.\min}$ is the vertical minimum distance of acid-rock reaction, and L is the horizontal wellbore length.

The deduction above is based on the factor that the distance of acid-rock reaction is less than the distance of mud immersion; if the distance of acid-rock reaction is more than the distance of mud immersion, we can use the same method to calculate the skin factor, which has the same formula as (15), only $a_v(x)$ is more than $d_v(x)$, so there are no details here.

2.1.2. Calculation of Total Skin Factor. In the y-z plane at any location of HW, we select an infinitesimal section whose length is dx; the production formula can be described as

$$dq = \frac{774.6K_v\Delta p^2}{T\mu_g Z} \frac{dx}{\ln[h/(2r_w)] + S(x)}, \quad (17)$$

where K_v is the vertical permeability of gas reservoir.

So the productivity formula of total HW is given as

$$q = \int_0^L dq\,dx = \frac{774.6K_v\Delta p^2}{T\mu Z} \int_0^L \frac{dx}{\ln[h/(2r_w)] + S(x)}. \quad (18)$$

Under normal conditions, the productivity formula is described considering skin factor as follows:

$$q = \frac{774.6K_v L\Delta p^2}{T\mu_g Z\left(\ln(h/2r_w) + S_{eq}\right)}. \quad (19)$$

Comparing (18) and (19), the skin factor in isotropic formation can be got from the following model:

$$S_{eq} = \frac{L}{\int_0^L (dx/(\ln[h/(2r_w)] + S(x)))} - \ln\frac{h}{2r_w}. \quad (20)$$

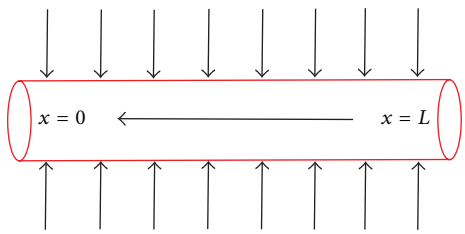

Figure 5: Coupling model between reservoir and wellbore.

If the anisotropy is taken into account, (20) will be changed to

$$S_{eq} = \frac{L}{\int_0^L \left(dx/\left(\ln[\beta h/(\beta+1)r_w] + S(x)\right)\right)} - \ln\frac{\beta h}{(\beta+1)\,r_w}. \tag{21}$$

2.1.3. Productivity Formula of Horizontal Well after Acidizing. The formula of skin factor after acidizing, namely, (21), can be added on Joshi's productivity formula [24] to get the productivity index of per unit length of HW:

$$J_h = \left(\frac{774.6K_h h}{\left(T\mu_g ZL\right)}\right)\left(\ln\left[\frac{a+\sqrt{a^2-(L/2)^2}}{L/2}\right] + \frac{\beta h}{L}\left(\ln\frac{\beta h}{2r_w} + S_{eq}\right)\right)^{-1}, \tag{22}$$

where a is a semimajor axis of elliptic drainage area.

So from formation to wellbore, the flow rate of per unit length of HW can be written as

$$q_h(x) = J_h\left[p_e^2 - p_{wf}^2(x)\right], \tag{23}$$

where p_e is the driving pressure of gas reservoir.

2.2. Flow in the Wellbore. Because of the pressure drop in the wellbore [25–30], the flow rate is changeable at any location along the wellbore; meanwhile, the total rate in the wellbore is increasing gradually. When the HW is treated by acidizing, the production is greatly increased, so an assumption can be made that the condition of fluid in the wellbore is turbulent flow, for the barefoot well completion, the oil flow from the formation to the wellbore uniformly, as is shown in Figure 5.

Based on the volume conservation between reservoir and wellbore, the relationship between flow rate change in the wellbore and that from formation to wellbore can be written as

$$\frac{dQ(x)}{dx} = -q_h(x). \tag{24}$$

The symbol "–" at the right side of (24) indicates that fluid's flow direction is opposite to the x plane. For the reservoir with infinite outer boundary, the boundary conditions can be described as follows:

$$\lim_{x\to\infty} p_{wf}^2(x) = p_e^2, \qquad \lim_{x\to 0} p_{wf}^2(x) = p_{wf}^2. \tag{25}$$

Transforming the boundary condition as (25) shows into that related to flow rate,

$$\lim_{x\to\infty}\frac{dQ(x)}{dx} = 0, \qquad \lim_{x\to 0}\frac{dQ(x)}{dx} = -J_h\left(p_e^2 - p_{wf}^2\right). \tag{26}$$

Typically, the pressure gradient in the horizontal wellbore can be written as

$$\frac{dp_{wf}^2(x)}{dx} = 9.066\times 10^{-12}\lambda\frac{\gamma_g ZT}{D^5}Q^2(x), \tag{27}$$

where λ is the friction coefficient, D is the wellbore diameter, γ_g is the gas relative density, and $Q(x)$ is the total rate at any location of horizontal wellbore.

In fully turbulent flow zone, friction coefficient λ is always constant for a specific slotted liner or screen pipe:

$$\lambda = \frac{1}{4lg^2\left[\varepsilon/(3.7D)\right]}, \tag{28}$$

where ε is the wellbore coarse degree.

2.3. Solution Method for Productivity Model. Taking the derivative of (22) and (23), respectively,

$$\frac{dq_h(x)}{dx} + J_h\frac{dp_{wf}^2(x)}{dx} = 0, \tag{29}$$

$$\frac{d^2Q(x)}{dx^2} + \frac{dq_h(x)}{dx} = 0. \tag{30}$$

We can derive from (29) and (30) that

$$\frac{d^2Q(x)}{dx^2} - J_h\frac{dp_{wf}^2(x)}{dx} = 0. \tag{31}$$

Substituting (27) and (28) into (31), the following model can be obtained:

$$\frac{d^2Q(x)}{dx^2} - 9.066\times 10^{-20}J_h\lambda\frac{\gamma_g ZT}{D^5}Q^2(x) = 0. \tag{32}$$

Combining boundary conditions (26), the analytic solution when the HW's length tends to reach infinity can be got:

$$Q(x) = 55.56\frac{\mu_g D}{\gamma_g}\times\left[\sqrt{\frac{C_1}{6}}x + \left(\sqrt{\frac{3}{2C_1}}C_2\right)^{-1/3}\right]^{-2}, \tag{33}$$

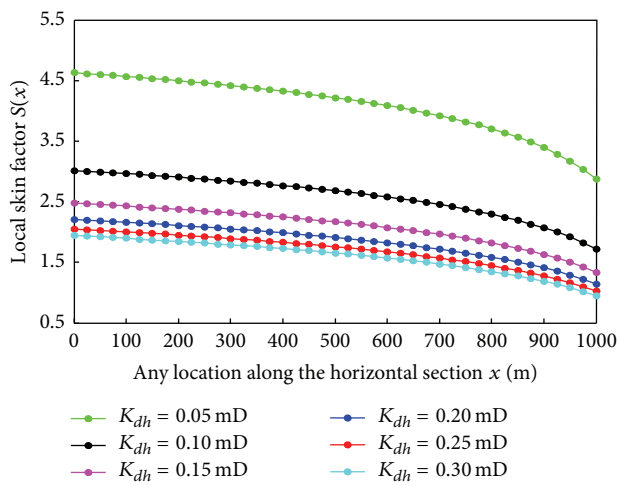

FIGURE 6: Effect of DZ's permeability (K_{dh}) on skin factor (L = 1000 m, r_w = 0.1 m, ε = 0.00016 m, γ_g = 0.56, μ_g = 0.023 mPa·s, Z = 0.9, T = 366 K, h = 10 m, p_{wf} = 20 MPa, K_h = 0.6 mD, K_v = 0.1 mD, K_{ah} = 1.2 mD, $d_{v.\max}$ = 1.6 m, $d_{v.\min}$ = 0.2 m, $a_{v.\max}$ = 1.2 m, and $a_{v.\min}$ = 0.15 m).

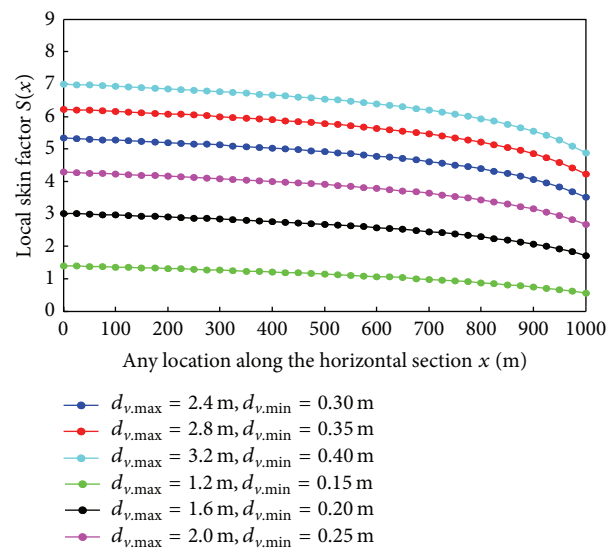

FIGURE 7: Effect of distance of mud immersion ($d_{v.\max}$, $d_{v.\min}$) on skin factor (L = 1000 m, r_w = 0.1 m, ε = 0.00016 m, γ_g = 0.56, μ_g = 0.023 mPa·s, Z = 0.9, T = 366 K, h = 10 m, p_{wf} = 20 MPa, K_h = 0.6 mD, K_v = 0.1 mD, K_{ah} = 1.2 mD, K_{dh} = 0.1 mD, $a_{v.\max}$ = 1.2 m, and $a_{v.\min}$ = 0.15 m).

where $C_1 = 5.04 \times 10^{-18} \lambda J_h Z T \mu_g / D^4$ and $C_2 = 1.8 \times 10^{-2} J_h \gamma_g \Delta p^2 / (\mu_g D)$.

In (33), $Q(x)$ indicates the total production that $x > x'$, where x' means any location along the wellbore, so the production of HW can be described by

$$Q = Q(0) - Q(L). \tag{34}$$

Namely,

$$Q = 55.56 \frac{\mu_g D}{\gamma_g} \left[\sqrt{\frac{3}{2C_1}} C_2 \right]^{2/3} - 55.56 \frac{\mu_g D}{\gamma_g} \left[\sqrt{\frac{C_1}{6}} L + \left(\sqrt{\frac{3}{2C_1}} C_2 \right)^{-1/3} \right]^{-2}. \tag{35}$$

3. Results and Discussion

3.1. Sensitivity Analysis on Skin Factor of Horizontal Well after Acidizing. Figure 6 shows the distribution of local skin factor along the wellbore under different DZ's permeability. From Figure 6, we can obviously find that the local skin factor decreases from the heel to the toe; meanwhile, the local skin factor decreases as the permeability of DZ section is increased, but the tendency of increasing is not constant, as Figure 6 shows. Namely, when the DZ's permeability is rising from 0.05 mD to 0.10 mD, the local skin factor's variation range is about 1.6, but when the DZ's permeability is changing from 0.10 mD to 0.30 mD, the local skin factor decreases by only 1, which demonstrates that, for the DZ with high permeability, it is difficult to obtain smaller skin factor, so any other stimulation treatment must be taken to decrease the skin factor.

Figure 7 compares the distribution of local skin factor under different mud immersion's distance. As is shown in Figure 7, when the maximum and minimum distance of mud immersion are rising from (1.2 m, 0.15 m) to (1.6 m, 0.20 m), respectively, the local skin factor increases significantly, but when they increase from (1.6 m, 0.20 m) to (3.2 m, 0.40 m), the local skin factor's range of variation is less than the above mentioned case; that is to say, the local skin factor after acidizing is increasing as the advancing of distance of mud immersion, but the tendency is changed gradually; this shows that if the DZ has a long distance of mud immersion near the wellbore, the acidizing treatment has a small contribution to decrease the skin factor, so an in-depth acidification technology should be taken into account in order to increase the distance of acid-rock reaction largely and improve the DZ in the great degree.

Figure 8 provides the comparison of distribution of local skin factor along the wellbore under different permeability of AZ. As demonstrated in Figure 8, the permeability of AZ does not change the distribution trend of local skin factor along the wellbore; it also attains maximum at the heel, while it attains minimum at the toe. When the permeability of AZ ranges from 0.8 mD to 1.0 mD, the local skin factor decreases sharply, while, from 1.0 mD to 1.8 mD, the value of local skin factor only has fewer changes; namely, the local skin factor decreases by the increasing of permeability of AZ, but the tendency is more and more gentle, so the conclusion can be drawn when the permeability of AZ reaches a certain extent; if we want to decrease the skin factor through increasing permeability of AZ, it will have little contribution; any other stimulation treatments must be taken.

Comparing the curves of distribution of local skin factor under different distance of acid-rock reaction as illustrated in Figure 9, it is obvious to find that when the distance of acid-rock reaction ranged from (0.8 m, 0.10 m) to (1.0 m, 0.125 m),

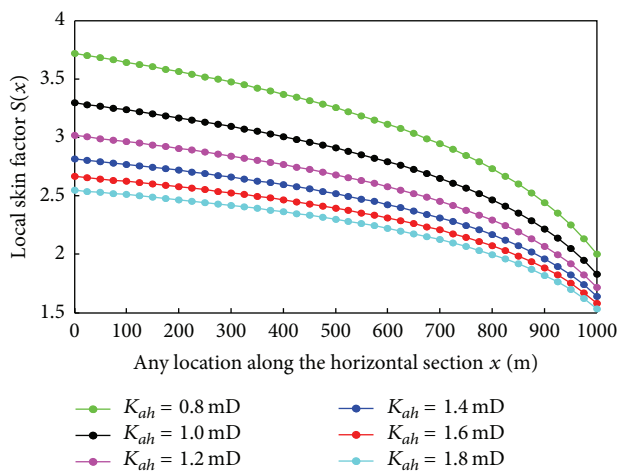

Figure 8: Effect of AZ's permeability (K_{ah}) on skin factor (L = 1000 m, r_w = 0.1 m, ε = 0.00016 m, γ_g = 0.56, μ_g = 0.023 mPa·s, Z = 0.9, T = 366 K, h = 10 m, p_{wf} = 20 MPa, K_h = 0.6 mD, K_v = 0.1 mD, K_{dh} = 0.1 mD, $d_{v.\max}$ = 1.6 m, $d_{v.\min}$ = 0.2 m, $a_{v.\max}$ = 1.2 m, and $a_{v.\min}$ = 0.15 m).

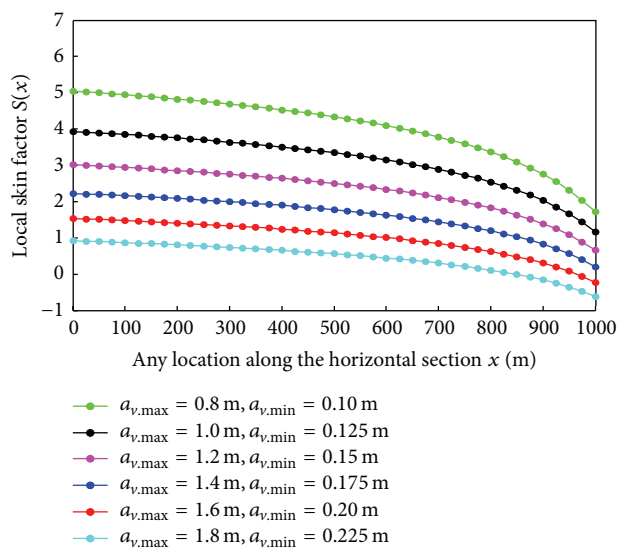

Figure 9: Effect of distance of acid-rock reaction ($a_{v.\max}$, $a_{v.\min}$) on skin factor (L = 1000 m, r_w = 0.1 m, ε = 0.00016 m, γ_g = 0.56, μ_g = 0.023 mPa·s, Z = 0.9, T = 366 K, h = 10 m, p_{wf} = 20 MPa, K_h = 0.6 mD, K_v = 0.1 mD, K_{ah} = 1.2 mD, K_{dh} = 0.1 mD, $d_{v.\max}$ = 1.6 m, and $d_{v.\min}$ = 0.2 m).

respectively, the local skin factor decreases sharply, but when the distance of acid-rock reaction increases from (1.0 m, 0.125 m) to (1.8 m, 0.225 m), the local skin factor only has a small increase; namely, the local skin factor decreases by the increasing of distance of acid-rock reaction, but it will reach a constant when the distance has become a certain degree, so this will reveal that, during HW's acidizing treatment, reasonable acid type should be chosen, which can not only increase the distance of acid-rock reaction, but also meet the demand of economic benefit.

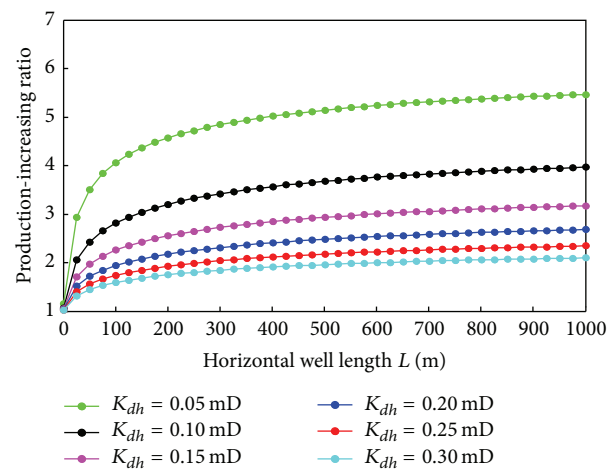

Figure 10: Effect of DZ's permeability (K_{dh}) on production-increasing ratio (L = 1000 m, r_w = 0.1 m, ε = 0.00016 m, γ_g = 0.56, μ_g = 0.023 mPa·s, Z = 0.9, T = 366 K, h = 10 m, p_{wf} = 20 MPa, K_h = 0.6 mD, K_v = 0.1 mD, K_{ah} = 1.2 mD, $d_{v.\max}$ = 1.6 m, $d_{v.\min}$ = 0.2 m, $a_{v.\max}$ = 1.2 m, and $a_{v.\min}$ = 0.15 m).

3.2. Sensitivity Analysis Study on Production-Increasing Ratio of Horizontal Well after Acidizing. The relationship curves between production-increasing ratio and HW length at different DZ's permeabilities are calculated and presented in Figure 10. As is shown in Figure 10, when the DZ's permeability is constant, the production-increasing ratio increases as the HW length is increased, but when the HW length reaches a certain extent, the production-increasing ratio becomes constant; meanwhile, the production-increasing ratio decreases as the permeability of DZ is increased, but the tendency will become more and more gentle; that is to say, the lower the DZ's permeability is, the higher the production-increasing ratio will be. So when the distance of mud immersion is constant, if the permeability of DZ is low, the acidizing effect will be better, which is also the reason why acidizing had been widely used in developing the gas and oil field.

Figure 11 shows the relationship between production-increasing ratio and HW length under different distances of mud immersion. From Figure 11, it is obvious to find that by the increasing of distance of mud immersion, the production-increasing ratio decreases; this is because when the distance of acid-rock reaction is constant, the deeper the distance of mud immersion is, the smaller the scale transformation will be, so for the HW with deep DZ, acidizing treatment will be ineffective and fracturing can be a good choice to stimulate, which not only can improve the DZ to a great degree, but also can increase the vertical permeability, eventually improving the fluidity of oil near the wellbore.

Figure 12 compares the relationship curves between production-increasing ratio and HW length under different permeability of AZ. It illustrates that by the increasing of permeability of AZ, the production-increasing ratio also increases, but the extent will be more and more gentle, eventually tending to a constant value. This is because when the permeability of DZ is constant, if the permeability of AZ

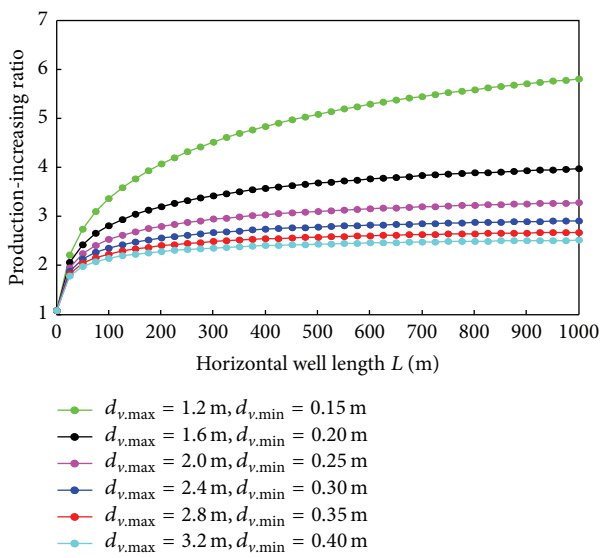

Figure 11: Effect of distance of mud immersion ($d_{v.\max}$, $d_{v.\min}$) on production-increasing ratio (L = 1000 m, r_w = 0.1 m, ε = 0.00016 m, γ_g = 0.56, μ_g = 0.023 mPa·s, Z = 0.9, T = 366 K, h = 10 m, p_{wf} = 20 MPa, K_h = 0.6 mD, K_v = 0.1 mD, K_{ah} = 1.2 mD, K_{dh} = 0.1 mD, $a_{v.\max}$ = 1.2 m, and $a_{v.\min}$ = 0.15 m).

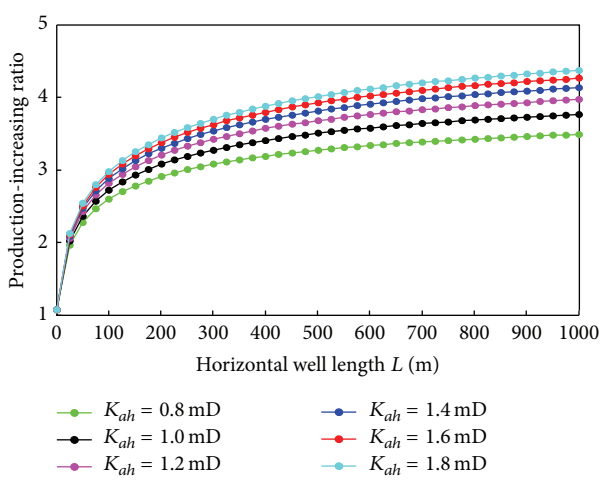

Figure 12: Effect of AZ's permeability (K_{ah}) on production-increasing ratio (L = 1000 m, r_w = 0.1 m, ε = 0.00016 m, γ_g = 0.56, μ_g = 0.023 mPa·s, Z = 0.9, T = 366 K, h = 10 m, p_{wf} = 20 MPa, K_h = 0.6 mD, K_v = 0.1 mD, K_{dh} = 0.1 mD, $d_{v.\max}$ = 1.6 m, $d_{v.\min}$ = 0.2 m, $a_{v.\max}$ = 1.2 m, and $a_{v.\min}$ = 0.15 m).

is higher, it will indicate that acidizing fluid improves the DZ perfectly, but when the permeability of AZ reaches high levels, the contribution of acidizing to production-increasing ratio will become small, so during application of acidizing, a reasonable acid type and an acid concentration should be taken into account in order to get an optimal effect.

Figure 13 compares the relationship curves between production-increasing ratio and HW length under different distances of acid-rock reaction. As demonstrated in Figure 13, when the distance of mud immersion is constant,

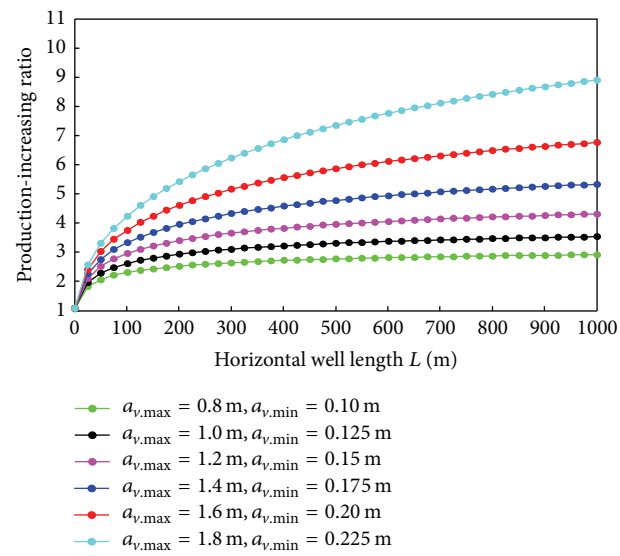

Figure 13: Effect of distance of acid-rock reaction ($a_{v.\max}$, $a_{v.\min}$) on production-increasing ratio (L = 1000 m, r_w = 0.1 m, ε = 0.00016 m, γ_g = 0.56, μ_g = 0.023 mPa·s, Z = 0.9, T = 366 K, h = 10 m, p_{wf} = 20 MPa, K_h = 0.6 mD, K_v = 0.1 mD, K_{ah} = 1.2 mD, K_{dh} = 0.1 mD, $d_{v.\max}$ = 1.6 m, and $d_{v.\min}$ = 0.2 m).

the production-increasing ratio increases sharply by the increasing of distance of acid-rock reaction; this is because the bigger the distance of acid-rock reaction is, the greater the improvement degree (including DZ and no DZ) will be, eventually enhancing the production-increasing ratio. So during acidizing of HW, retarded acid will be a good choice to increase the distance of acid-rock reaction and content to the high permeability in AZ.

4. Conclusions

The model for skin factor and productivity of HW after acidizing is established and solved, during which HW is divided into many segments; at any segment, the method of displacement between two similar flow modes is used. Type curves of skin factor and production-increasing ratio are illustrated, and the factors affecting skin factor and production-increasing ratio are analyzed. Analysis results show after acidizing as the increasing of the distance of mud immersion, local skin factor of HW increases, while as the increasing of DZ's permeability, AZ's permeability and distance of acid-rock reaction, it decreases, production-increasing ratio increases as the increasing of HW length, AZ's permeability and distance of acid-rock reaction, while it decreases as the increasing of DZ's permeability and distance of mud immersion.

Nomenclature

a: Semimajor axis of elliptic drainage area, m
a_v: Vertical radius of acidizing zone, m

$a_{v.\max}$: Vertical maximum distance of acid-rock reaction, m
$a_{v.\min}$: Vertical minimum distance of acid-rock reaction, m
β: Anisotropy coefficient
D: Wellbore diameter, m
d_h: Horizontal radius of damage zone, m
d_v: Vertical radius of damage zone, m
$d_{v.\max}$: Vertical maximum distance of mud immersion, m
$d_{v.\min}$: Vertical minimum distance of mud immersion, m
λ: Friction coefficient
H: Distance between two constant pressure lines, m
h: Gas reservoir thickness, m
J_h: Gas productivity index per unit, $m^3/(d{\cdot}MPa{\cdot}M)$
K_h: Permeability of formation, mD
K_v: Vertical permeability of gas reservoir, mD
K_{av}: Vertical permeability of acidizing zone, mD
K_{dv}: Vertical permeability of damage zone, mD
K_{dh}: Horizontal permeability of damage zone, mD
K_{ah}: Horizontal permeability of acidizing zone, mD
L: Horizontal well length, m
p_e: Driving pressure of gas reservoir, MPa
p_d: Pressure of damage zone's boundary, MPa
p_{wf}: Pressure of heel, MPa
$p_{wf}(x)$: Pressure at any location along the wellbore, MPa
Φ_d: Potential in the damage zone's boundary, $10^{-6}\ m^2/s$
Φ_1: Potential in constant pressure boundary, $10^{-6}\ m^2/s$
Δp_s: Pressure drop caused by skin factor, MPa
Δp: Production pressure drop of vertical well, MPa
q_h: Production of per unit length, m^3/d
q_{sc}: Production of horizontal gas well, m^3/d
Q: Production of horizontal well, m^3/d
r_w: Wellbore radius, m
S: Skin factor of vertical well
$S(x)$: Local skin factor of horizontal well
S_{eq}: Total skin factor of horizontal well
γ_g: Gas relative density
ε: Wellbore coarse degree, m
T: Gas reservoir temperature, K
μ_g: Gas viscosity, mPa·s
Z: Gas deviation factor.

Conflict of Interests

The authors declare that there is no conflict of interests regarding the publication of this paper.

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