A new Production prediction model of staged fracturing horizontal wells for tight gas reservoirs

Xiaogang Li1*, Zhengfu Feng1, Changyin Liu2, Zhiyu Sun2, Qian Chen3, Zhaozhong Yang1, Yijun Yuan4

1State Key Laboratory of Oil and Gas Reservoir Geology and Exploitation, Southwest Petroleum University, Chengdu, Sichuan, China
2State Key Laboratory of Shale Oil Gas Accumulation Mechanism and Effective Development, SINOPEC, Beijing, China
3No. 1 Gas Production Plant, Sinopec Southwest Petroleum Branch, Deyang, Sichuan, China
4Southwest Exploration and Development Company, CNPC Tarim Oilfield Company, Korla, Xinjiang, China

*Corresponding email: swpuadam@126.com.

Abstract. Numerical simulations have been frequently used to predict reservoir productivity and optimize the development scheme of non-conventional reservoirs. In this study, a new numerical simulation model of the gas flow based on the embedded discrete fracture model, which considers the start-up pressure gradient and stress sensitivity in the matrix system, is established. The proposed model is numerically solved and validated using the field production data. Based on the novel model, the sensitivity effect of the start-up pressure, stress sensitivity, and fracture layouts on production are considered. The results indicate the production of each fracture is distributed as U-shaped, the production of the outermost two fractures have the highest production.

1. Introduction
The exploration and development of unconventional oil and gas reservoirs are increasingly becoming the focus of research. According to some estimates, the global tight gas reserves are approximately 209.72 trillion m³ [1]. These reservoirs are an important part of the unconventional resources. However, these reservoirs exhibit poor reservoir properties. Often, their porosity is less than 10% and the original formation permeability is less than 0.1 × 10⁻³ μm², which means that viable production cannot be achieved without fracturing [2-5]. In such conditions, the technology of staged fracturing horizontal wells is generally applied to optimize the single-well production for the economic viability of such gas reservoirs.

The numerical method can accurately predict the development performance of oil and gas reservoirs under various production conditions. This method mainly involves three models: the continuum, discrete fracture, and embedded discrete fracture models.

To simplify the simulation and improve the efficiency of calculations, Lee [6-7] first proposed the embedded DFM (EDFM). Li and Lee proposed a method to calculate the conductivity coefficient between the fracture network and discrete matrix [8]. Jose established a hydraulic fracture simulation.
software based on the EDFM. The DFM is restricted by the unstructured grids and low calculation efficiency. The EDFM combines the advantages of the continuum and discrete fracture models, thereby improving the calculation efficiency [9]. Therefore, in the study, model is established based on the EDFM.

The general characteristics of tight sandstone gas reservoirs are low porosity, low permeability, and high-water saturation. Therefore, the start-up pressure gradient and stress sensitivity effect are typically characterized in the flow of reservoirs, which should be considered in simulation model.

Previous studies have indicated that the start-up pressure gradient and stress sensitivity affect production. For the start-up pressure gradient. McLatchie et al. [10] were the first to study the effect of stress sensitivity experimentally. Ding [11] experimentally measured the start-up pressure gradient and found that it increased with a decrease in the reservoir pressure. Based on experimental results obtained in the laboratory, Xu confirmed that the relationship between the start-up pressure gradient and permeability was a power function. [12] Therefore, these two factors are introduced to the simulation model to simulate the flow in tight sandstone gas reservoirs more realistically and correctly.

In conclusion, this study established a new production prediction numerical model based on the EDFM by considering the start-up pressure gradient and stress sensitivity. Furthermore, the effects of various characteristics, including the fracture layouts, were analyzed. Finally, the factors that affect the productivity of horizontal wells in tight gas reservoirs were investigated and suitable approaches proposed to optimize the development scheme to increase production and profits.

2. Model description

2.1 Hypothesis

Based on the theory of the single-phase gas flow in tight sandstone gas reservoirs, we studied the production performance of staged fracturing horizontal wells in a 2D tight sandstone gas reservoir. The assumptions of the single-phase gas flow model are as follows:

1. Fluid flows in a rectangular reservoir at a constant temperature.
2. The 2D flow ignores the effect of gravity.
3. The gas reservoir has heterogeneity and anisotropy; both the rock and fluid are slightly compressible.
4. The fluid flowing in fractures obeys Darcy’s law, whereas the fluid flowing in the matrix does not.
5. Fractures completely cross the reservoir, and the height of a fracture is equal to the thickness of the reservoir.

2.2 Seepage equations

Considering the effect of the start-up pressure gradient of the matrix system, the gas flow differential equation is given as

\[
\frac{\partial}{\partial x} \left[ \frac{k_m}{B_{mu} \mu} \left( \frac{\partial p_m}{\partial x} - \lambda \right) \right] + \frac{\partial}{\partial y} \left[ \frac{k_m}{B_{mu} \mu} \left( \frac{\partial p_m}{\partial y} - \lambda \right) \right] + q_m = \frac{\partial}{\partial t} \left( \frac{\varphi_m}{B_m} \right)
\]

When the effect of the stress sensitivity on the matrix is considered, the matrix permeability varies with pressure for each time step:

\[
k_m = k_{m0} \cdot e^{-\alpha(p_i - p_m)}
\]

The initial condition of the model is

\[
p_m(x, y, 0) = p_i \quad (0 \leq x \leq L_x, 0 \leq y \leq L_y)
\]

The boundary conditions (BC) of the model are

BC (outer): a closed boundary;
BC (inner): a stable bottom hole pressure.
Fluid flow is considered to be one dimensional for the fracture system because of the dimensional reduction in the EDFM. Its mathematical model is as follows:

\[
\frac{\partial}{\partial x} \left[ k_f \frac{\partial p_f}{\partial x} \right] + q_f = \frac{\partial}{\partial t} \left( \phi_f \right)
\]

(5)

where \( p_f \) is the fracture pressure, MPa; \( q_f \) is the flow per unit of time in or out of the fracture, 1/s; \( \phi_f \) is the porosity of the fracture in the matrix, non-dimensional; \( k_f \) is the fracture permeability, \( \mu m^2 \); and \( B_f \) is the gas volume coefficient of the fracture, non-dimensional.

The initial condition of the model is:

\[
P_f(x,0) = P_i.
\]

(6)

The BCs of the model are

BC (outer): a closed boundary;

BC (inner): a stable bottom hole pressure.

\[
\left\{ \frac{\partial p_f}{\partial x} \right|_{x=0/L_f} = 0,
\left\{ \frac{\partial p_f}{\partial x} \right|_{y=0/L_y} = 0
\]

(4)

\[
P_{wf} = C
\]

The above formulas constitute the mathematical models of the gas flow for the matrix and fracture systems.

3. Embedded discrete fracture model

To simplify the fracture model, Lee et al. [6-7] proposed the EDFM. The main idea behind this model is to divide the whole reservoir into orthogonal grids so that the fracture is cut into segments using the matrix grid boundary. The fractures in the EDFM are cut into segments using matrix grids. One grid is added for each fracture segment. The process of adding fracture grids is shown in figure 1.

![Figure 1](image)

Figure 1. Schematic of grid numbers of matrix and fracture systems.

In 1997, Hearn proposed to establish the flow relations within diversion fractures using the non-neighboring connections (NNCs). [13] Based on the different characters of neighbor grids, NNCs can be divided into three types: (1) grid connection between the fracture segment and the matrix grid it passes through, such as matrix grid 7 and fracture grid 26; (2) the connection between neighbor fracture grids of the same fracture, such as fracture grids 26 and 27; (3) the connection between fracture grids at the intersection of different fractures, such as fracture grids 27 and 31. The flow exchange coefficient between the matrix and fracture is given as
where $d^*$ is the average normal distance from the matrix grid to the surface of the fracture (in m).

Therefore, the general formula of the conductivity coefficient of NNC is

$$T_{\text{NNC}} = \frac{k_{\text{NNC}} A_{\text{NNC}}}{d_{\text{NNC}}}$$  \hspace{1cm} (9)$$

where $k_{\text{NNC}}$ is the permeability of NNC, mD; $A_{\text{NNC}}$ is the contact area of NNC, m$^2$; and $d_{\text{NNC}}$ is the relative average distance of NNC, m.

To derive the calculation formula of NNC conductivity considering variable conductivity with the position in the same fracture, firstly, as shown in Figure 2, when the conductivity of fracture is certain, the potential difference is used to represent the pressure drop between neighbor grids, the flow between neighbor fracture grids is

$$q_{fb} = \frac{k_{fb} \Phi_{fb1} - \Phi_{fb2}}{L_{fb}}$$  \hspace{1cm} (10)$$

where $q_{fb}$ is the flow between neighbor fracture grids, m$^3$/d; $k_{fb}$ is the permeability of the fracture, mD; $\Phi_{fb1}$ and $\Phi_{fb2}$ are the potentials at the centers of fracture grids 1 and 2, respectively; and $L_{fb}$ is the distance between the centers of the neighbor fracture grids, m.

Assuming that the property of the flow within the neighbor fracture grids is constant, the flow rate passing through fracture grid 1 is equal to that of fracture grid 2. Therefore

$$-k_{fb1} \frac{\Phi - \Phi_{fb1}}{d_{f1-int}} = -k_{fb2} \frac{\Phi - \Phi_{fb2}}{d_{f2-int}}$$  \hspace{1cm} (11)$$

where $\Phi$ is the potential of the interface of neighbor fracture grids; $k_{fb1}$ and $k_{fb2}$ are, respectively, the permeabilities of fracture grids 1 and 2, mD; $d_{f1-int}$ is the distance between the center of fracture grid 1 and the interface, m; and $d_{f2-int}$ is the distance between the center of fracture grid 2 and the interface, m.

**Figure 2. Diagram of neighbor fracture grid.**

Defining $T_{fb1} = k_{fb1} / d_{f1-int}$ and $T_{fb2} = k_{fb2} / d_{f2-int}$, the conductivity of neighbor fracture grids within the variable conductivity fracture is calculated as

$$T_{\text{FF}} = \frac{\overline{wh}}{k_{fb1} + k_{fb2}}$$  \hspace{1cm} (12)$$

The grid where the horizontal wellbore intersects the fracture is named the well grid in this model. It relates to the horizontal well production, bottom-hole flow pressure, and pressure of the fracture grid.
The calculation formula derived about the fracture grid and borehole conductivity of the EDFM in the well model proposed by Peaceman as follows:

\[
WI_i = \frac{\Delta \theta \cdot k_i w_i}{\ln(r_e / r_w)}
\]  

(13) \[r_e = 0.14 \sqrt{L_f + h_f^2}
\]  

(14) where \(L_f\) is the distance of the fracture intersection from the borehole, m; \(h_f\) is the height at which the fracture intersects the borehole, m; and \(\Delta \theta\) is the central angle of the well contained in the fracture when the borehole passes through a fracture grid (its value is 2\(\pi\)).

4. Numerical model

Both the existing EDFM and finite difference method use rectangular grids to divide the matrix and fracture system to effectively solve the flow problem. Similarly, the finite difference scheme of the flow differential equation is derived for the EDFM and established for the corresponding production prediction model.

4.1 Derivation of finite difference scheme for matrix system

The semi-implicit finite difference scheme of the partial differential equation for the matrix flow is as follows:

\[
\frac{(\varphi_m / B_m)_{i,j}^{n+1} - (\varphi_m / B_m)_{i,j}^n}{\Delta t} = \left( \frac{k_m}{\mu B_m} \right)_{i,j}^n \cdot \frac{1}{\Delta x^2} \cdot (p_{i+1,j}^{n+1} - p_{i,j}^{n+1} - \lambda)
\]

\[
- \left( \frac{k_m}{\mu B_m} \right)_{i,j-1/2}^n \cdot \frac{1}{\Delta x^2} \cdot (p_{i,j+1}^{n+1} - p_{i,j}^{n+1} - \lambda)
\]

\[
+ \left( \frac{k_m}{\mu B_m} \right)_{i+1/2,j}^n \cdot \frac{1}{\Delta y^2} \cdot (p_{i,j+1}^{n+1} - p_{i,j}^{n+1} - \lambda)
\]

\[
- \left( \frac{k_m}{\mu B_m} \right)_{i-1/2,j}^n \cdot \frac{1}{\Delta y^2} \cdot (p_{i,j-1}^{n+1} - p_{i,j}^{n+1} - \lambda)
\]

\] 

(15) When the fracture segment is embedded in the matrix grid, we have

\[
q_{m,j} = \frac{(T_{mf})_{i,j}}{\mu} (p_{i,j}^m - p_f^m)
\]  

(16) where \(p_f^m\) is the pressure of the fracture grid embedded in the matrix grid \((i, j)\), MPa; and \((T_{mf})_{i,j}\) is the conductivity coefficient, mD·m.

The matrix grid corresponds to the fracture grid; therefore, in unit volume, the gas exchange flow rate converting to the ground is

\[
q_m^* = \frac{q_{m,j}}{V_b \cdot B_{mf}} = \frac{(T_{mf})_{i,j}}{\mu \cdot V_b \cdot B_{mf}} (p_{i,j}^m - p_f^m)
\]  

(17) \[
B_{mf} = \frac{2B_m B_f}{B_m + B_f}
\]  

(18) After the derivation and simplification:
\[ f_{i,j} = b_{i,j} p_{i,j}^{n+1} + a_{i,j} p_{i-1,j}^{n+1} + \left[ e_{i,j} - \frac{(T_{mf})_{i,j}}{\mu V_x B_{mf}} \right] p_{i,j}^{n+1} + d_{i,j} p_{i+1,j}^{n+1} + c_{i,j} p_{i,j-1}^{n+1} + g_{i,j} \lambda + \left( \frac{T_{mf})_{i,j}}{\mu V_x B_{mf}} \right) p_{i,j}^{n+1} \]  

Rewriting part of the formula:

\[ h_{i,j} = \frac{(T_{mf})_{i,j}}{\mu V_x B_{mf}} \]  

\[ e_{i,j} = \left[ \frac{k_m}{\mu B_m \Delta x^2} \right] \left( \frac{k_m}{\mu B_m \Delta y^2} \right) \left( \frac{k_m}{\mu B_m \Delta z^2} \right) \left( \frac{k_m}{\mu B_m \Delta x} \right) \left( \frac{k_m}{\mu B_m \Delta y} \right) \left( \frac{k_m}{\mu B_m \Delta z} \right) - \frac{\varphi_m e^*}{B_{mf} \Delta} - h_{i,j} \]  

Therefore, the general expression of the differential equation for the matrix system grid is

\[ f_{i,j} = b_{i,j} p_{i,j}^{n+1} + a_{i,j} p_{i-1,j}^{n+1} + e_{i,j} p_{i,j}^{n+1} + d_{i,j} p_{i+1,j}^{n+1} + c_{i,j} p_{i,j-1}^{n+1} + g_{i,j} \lambda + h_{i,j} (p_{i}^{n+1}) \]  

4.2 Derivation of finite difference scheme for fracture system

First, to realize the transformation of fracture segments in the physical model to the fracture grid in the calculation model, it is necessary to redefine the porosity of the fracture grid. The porosity of fracture segments without any fill material is 1. The porosity of the fracture grid is related to the geometric sizes of the fracture and matrix grids.

The volume of the fracture segment in each matrix grid is

\[ V_f = A_w \]  

Therefore, the porosity of the fracture grid is

\[ \varphi_f = \frac{V_f}{V_b} = \frac{A_w}{\Delta x \cdot \Delta y \cdot \Delta z} \]  

For the fracture system, using time and space discretization, it can be obtained as

\[ \frac{\varphi_f e^*}{B_{mf} \Delta t} \left[ (p_{f,1}^{n+1}) - (p_{f,1}^{n}) \right] = \frac{(T_{mf})_{k-1/2}}{\mu V_x (B_{f})^n_{k-1/2}} (p_{f,1}^{n+1}) - \frac{(T_{mf})_{k-1/2}}{\mu V_x (B_{f})^n_{k-1/2}} (p_{f,1}^{n}) + \frac{(T_{mf})_{k+1/2}}{\mu V_x (B_{f})^n_{k-1/2}} (p_{f,1}^{n+1}) + \frac{(T_{mf})_{k+1/2}}{\mu V_x (B_{f})^n_{k-1/2}} (p_{f,1}^{n}) + q_{Bf} \]  

When the fracture grid intersects the borehole, the source-sink term, \( q_{Bf} \), of fracture grids consists of the leakage from the matrix and the flow from the wellbore:

\[ q_{Bf} = q_{m} + q_{fw} \]  

Using the formula of the borehole coefficient calculation:

\[ q_{fw} = -\frac{(W_f)_k}{\mu} [(p_k^{n+1}) - (p_{fw})] \]  

The ground production with the flow from the fracture to the wellbore is

\[ q_{fw} = -\frac{(W_f)_k}{\mu V_x (B_{fw})^n_{k}} [(p_k^{n+1}) - (p_{fw})] \]
Among, $B_{lw}^n = B_{mf}$, Rewrite the part of formula:

$$f_k^n = -\frac{\phi_{Bk}^*}{B_{k}^n} \cdot (p_{i,j}^f)^n - \frac{(WT_{f})_h}{\mu V_{B}^n(B_{lw})_k^n} \cdot P_{wf}$$

$$bb_k = \frac{\mu V_{B}^n(B_{l})_k^{\frac{1}{2}}}{\mu V_{B}^n(B_{l})_k^{\frac{1}{2}}} + \frac{\mu V_{B}^n(B_{l})_k^{\frac{1}{2}}}{\mu V_{B}^n(B_{l})_k^{\frac{1}{2}}} + h_i + \frac{\phi_{Bk}^*}{B_{k}^n} \cdot (WT_{f})_h$$

The result of the differential equation for the fracture system is

$$f_k^n = a_k^n (p_{k-1}^f)^{n+1} + b_k^n (p_{k}^f)^{n+1} + c_k^n (p_{k+1}^f)^{n+1} + h_{i,j} (p_{i,j}^m)^{n+1}$$

The corresponding coefficient matrix is depicted in Figure 3. The pressure of the matrix and fracture grids in the new time step can be obtained by solving the large linear sparse system of equations. The flow rate of all grids where the fractures intersect with boreholes can be obtained by adding all the flow rates to get the actual gas ground production:

$$(q_{cox})^{n+1} = \sum_{k=1}^{n+1} \frac{(WT_{f})_h}{\mu V_{B}^n(B_{lw})_k^n (l(p_{i,j}^f)^{n+1})^2 - P_{wf}^2}$$

Figure 3. Diagram of the coefficient matrix.

5. Model verification
To evaluate the accuracy of the EDFM established in the preceding section, well 23-15HF was considered as an example. The values of the relevant parameters are listed in Table 1.

| Parameters of reservoir | Value | Parameters of fracture | Value |
|-------------------------|-------|------------------------|-------|
| Thickness of reservoir, m | 15 | Fracture number | 10 |
| Temperature, °C | 44 | Half-length of fracture, m | 130 |
| Initial formation pressure, MPa | 21.2 | Fracture interval, m | 150 |
| Flowing bottom-hole pressure, MPa | 16.7 | Fracture permeability, D | 30 |
| Formation permeability, mD | 0.015 | Fracture width, m | 0.005 |
| Formation porosity, % | 9.7 |

Based on the parameters of well 23-15HF listed in Table 1, the reservoir was set as a rectangular model with a length of 1500 m and a width of 800 m. The grid size was 10 × 10 m, and the horizontal well was 1400 m. This model was established to simulate daily production over the next 500 days.

Both the actual daily production and production calculated by the model are depicted in Figure 4. The results indicated that the changing trend of the analog output and the actual gas production was consistent. This demonstrated the accuracy of the model established in this study.
6. Model application

The H block in the Ordos Basin is a typical low-permeability tight sandstone gas reservoir. A horizontal well from this block was used to demonstrate the applicability of the proposed model. The relevant parameters are listed in Table 2.

Table 2. Relevant parameters for simulation

| Parameters                          | Value       | Parameters                          | Value       |
|-------------------------------------|-------------|-------------------------------------|-------------|
| Size of gas reservoir, m            | 1000 x 600  | Reservoir temperature, K            | 353         |
| Thickness of reservoir, m           | 30          | Fracture number                     | 8           |
| Length of horizontal well, m        | 600         | Half-length of fracture, m          | 100         |
| Radius of well, m                   | 0.12        | Fracture interval, m                | 80          |
| Initial formation pressure, MPa     | 26          | Fracture permeability, D            | 30          |
| Flowing bottom-hole pressure, MPa   | 20          | Grid size                           | 10 x 10     |
| Formation permeability, mD          | 0.45        | Time step, d                        | 1           |
| Formation porosity, %               | 8.56        |                                     |             |

We set the flowing bottom-hole pressure at 20 MPa to simulate the pressure after production for 45, 90, 180, and 360 days. The pressure distribution is depicted in Figure 5.

Figure 4. Production fitting comparison.

Figure 5. Pressure distribution: (A) 45 days (B) 90 days (C) 180 days (D) 360 days.

Figure 5 exhibits the pressure distribution at various production stages. With time, the pressure at the fracture borehole gradually decreased from 22 MPa in 45 days to 21.5 MPa in 90 days before stabilizing at approximately 21 MPa in 360 days.
The daily and accumulated gas production curves of this gas reservoir are depicted in Figure 6. The daily production curve indicates a rapidly decreasing trend at the initial stage. The accumulated production increased with the progress of production, but the growth rate gradually slowed down.

![Figure 6. Daily and accumulated production curves.](image)

To study the production contribution of each fracture, the accumulated production of a fracture for 360 days is plotted in Figure 7. From the bar chart, the production of each fracture is distributed as U-shaped. The production of the outermost two fractures was the highest.

![Figure 7. Accumulated production of single fracture for 360 days.](image)

7. Conclusions
In this study, we proposed a new EDFM, comprehensively considering the non-Darcy flow in the matrix system, based on the unstable flow theory of tight sandstone gas reservoirs. We introduced the start-up pressure gradient and stress sensitivity coefficient and considered the fracture layouts. Based on the finite difference method, the numerical simulation was performed considering the factors affecting the productivity of staged fracturing horizontal wells in tight gas reservoirs. The modeling results demonstrated the accuracy of the model established in this study. Besides, the production of each fracture is distributed as U-shaped, the production of the outermost two fractures have the highest production.

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