An Investigation of Hydraulic-Fracturing Applied to Marine Gas Hydrate Reservoirs

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Abstract. Engineers have been struggling to harvest natural gas from the marine hydrates through drilling wells in the past two decades. The harvesting process has not been successful due to engineering problems such as wellbore collapse and sand production. This study proposes to use frac-packing method to address the wellbore collapse and sand production issues to break through the bottleneck of commercial production of natural gas from marine gas hydrates. An analytical model was developed to describe sequential initiation and simultaneous propagation of multiple vertical fractures in horizontal wells for frac-packing gas hydrate reservoirs. Result of sensitivity analyses with the models indicates that to frac-pack horizontal gas hydrate wells for solid-production control, increasing injection rate and flow behavior index of fracturing fluid will create more friction and thus more resistance to flow in large fractures, promoting the creation of more short fractures, and thus larger treated reservoir volume for higher gas production rate and gas recovery.

1. Introduction

Natural gas hydrates (NGH) are ice-like structures in which gas, most often gas, is trapped inside of water molecules. Unlike the ice gas hydrates are in fact highly flammable, a property that makes these crystalline structures an attractive future energy source. Hydrates are a much more abundant source of natural gas than conventional deposits. According to the U.S. Geological Survey, global stocks of gas hydrates range account for at least 10 times the supply of conventional natural gas deposits, with between 100,000 and 300,000,000 trillion cubic feet of gas yet to be discovered. If these sources of natural gas could be safely, efficiently and cheaply tapped into, gas hydrates could potentially displace coal and oil as the top sources of the world’s energy [1].

Since 2002, Canada, the United States, Japan, China and India have carried out well testing and production of NGH[2–7]. Max and Johnson[8] reviewed the current practices in exploration and production of oceanic natural gas hydrate. There are mainly four methods for gas production from Nature Gas Hydrate (NGH) deposit: 1) depressurization [9,10]– this method should decrease the pressure in NGH deposit below the hydrate dissociation pressure; 2) thermal stimulation[11–13]– this approach will use external heat to make the temperature in the NGH deposit above hydrate dissociation temperature with hot water/brine/steam; 3) thermodynamic inhibitor injection[14,15]–this technique is designed to inject chemicals, such as salts and alcohols, to change the hydrate pressure–
temperature equilibrium conditions; 4) a combination of these methods[16]. Guo and Shan[17] presented a feasibility study of harvesting natural gas from seabed hydrates using moving risers.

The energy industry consensus is that commercial-scale production remains years away due to unsolved technical and environmental issues. Engineers have been struggling to harvest natural gas from the marine hydrates through drilling wells in the past two decades. The harvesting process has not been successful due to engineering problems such as wellbore collapse and sand production [18]. This study proposes to use frac-packing method to address the wellbore collapse and sand production issues to break through the bottleneck of commercial production of natural gas from marine gas hydrates. Frac packing is a technology that is widely used in developing unconsolidated high-permeability oil reservoirs to mitigate sand production problems [19]. It is a completion technique that merges two distinct processes – hydraulic fracturing and gravel packing. Instead of using gravel, sand and or silt may be used to fill in the fractures and block the fine particles that are otherwise produced from gas hydrate reservoirs during depressurization. However, it is not clear how fractures are created in the gas hydrate deposits. The fracturing process is investigated through mathematical modeling in this investigation.

Early research work on fracture creation was reported by Roussel and Sharma [20], Manchanda and Sharma[21] and Roussel et al. [22]. Recent investigations were performed by Rucker et al. [23], King and Valencia[24] and Li et al. [25]. They have shown that geological conditions, including the presence of natural fractures, in-situ formation stresses, and stress shadowing of passive hydraulic fractures around the active hydraulic fractures, play important roles in controlling propagation of hydraulic fractures. However, gas hydrate reservoirs are much more homogeneous than conventional oil and gas reservoirs. Mathematical models for homogeneous reservoirs may be used for describing fracture creation and propagation. Conservation of energy and calculus of variation were utilized to form a hierarchical fracture model by Cheng[26] to describe the fracture complexity. Following Cheng et al.’[27] work, Feng et al. [28] defined a fracture complexity indicator as the number of fracture branches. Result of their analyses indicates that the fracture complexity increases near linearly with the fluid injection rate and time. The fracture complexity also increases with the elastic modulus of rock, which is consistent with observations in the practice of volume fracturing of shale gas formations. Nevertheless, Cheng’s [26] model and Feng et al’s[28] model do not provide quantitative description of the uneven propagation of fracture branches.

This work developed an analytical solution in closed-form to describe formation of vertical fractures. Sequential initiation and simultaneous propagation of multiple vertical fractures with non-Newtonian fluid in horizontal wells were mathematically described. The effects of fluid injection rate and flow behavior on fracture length were identified. An analytical model describing fluid flow in horizontal fractures was also derived for CO2-gas fracturing vertical wells. This model is prepared for designing effective frac-packing of gas hydrate reservoirs.

2. MATHEMATICAL MODEL

Hydraulic fractures open against the minimum stress and propagate in the maximum stress direction. Wherever the formation stress in the vertical direction is greater than the stresses in the horizontal directions, vertical fractures are created [20]. Horizontal wells are drilled to create rectangular hydraulic fractures for improving productivity of oil and gas wells [29]. An analytical model of vertical fractures in horizontal wells for describing sequential initiation and simultaneous propagation of multiple vertical fractures with non-Newtonian fluid in horizontal wells was mathematically described. The effects of fluid injection rate and flow behavior on fracture length were identified. An analytical model describing fluid flow in horizontal fractures was also derived for CO2-gas fracturing vertical wells. This model is prepared for designing effective frac-packing of gas hydrate reservoirs.

\[
x = \left( \frac{2n + 2}{2n + 1} C_1 \right)^{\frac{2n+1}{2n+2}} t^{\frac{2n+1}{2n+2}}
\]  

(1)
where x is the fracture propagating distance (length) in ft; n is fluid flow behavior index (dimensionless); t is flow injection time in second, and Πn is a group of constants defined as

\[
C_1 = \left[ \frac{372.25 \cdot g \cdot q \cdot (P_f - P_i)}{K_h} \right]^{\frac{1}{2n+1}} \left[ \frac{0.5q_i}{(3+n^{-1})h_f} \right]^{\frac{n}{2n+1}}
\]  

(2)

where g is the gravitational acceleration factor in lbm-ft/lbf-s^2; qi is the injection rate of fracturing fluid into one side of perforation cluster in ft^3/s (the total injection rate per cluster is 2); Pi is pressure outside the perforation cluster in lbf/ft^2; P_f is the pressure at fracture tip in lbf/ft^2; K is fluid consistency index in cp; and h is fracture height in ft. The dynamic average fracture width is expressed as

\[
w = \frac{\left( \frac{2n+2}{2n+1} \right) \left( \frac{2n+2}{2n+1} C_1 \right) \frac{1}{h_f}}{q_i^{\frac{1}{2n+2}}}
\]  

(3)

where w is the average fracture width in ft.

When the width of the fracture reaches a critical value wc, the rock stress at the initiation point of the fracture should cause failure of rock and initiate the second fracture. The critical average fracture width may be calculated by wc = where is the maximum fracture width at the wellbore which can be estimated using Rahman and Rahman’s[30] equation:

\[
w_f = 9.15^{\frac{1}{2n+2}} \cdot 3.98^{\frac{n}{2n+2}} \left[ 1 + \frac{2.14n}{n} \right]^{\frac{n}{2n+2}} \cdot \left[ \frac{q_i h_f x_f}{\frac{1}{2} E} \right]^{\frac{1}{2n+2}}
\]  

(4)

where E is the Young’s modulus of formation rock, xf is the fracture length from wellbore to the fracture tip. Inserting w = wc into Eq. (3) and solving for time t give the critical time for the first fracture to reach the critical length:

\[
t_{c1} = \frac{w_c h_f}{q_i \left( \frac{2n+2}{2n+1} \right) \left( \frac{2n+2}{2n+1} C_1 \right)^{\frac{1}{2n+2}}}
\]  

(5)

Letting t = tc in Eq. (1), the critical length of the first fracture at the critical time is expressed as

\[
x_{01} = \left( \frac{2n+2}{2n+1} C_1 \right)^{\frac{2n+1}{2n+2}} t_{c1}^{\frac{2n+1}{2n+2}}
\]  

(6)

Assuming the width of the first fracture stabilizes at wc, the additional propagation length of the first fracture after the second fracture is created can be expressed by

\[
x_i = -x_{01} + \frac{n+1}{n} \cdot C_i \left( \frac{n}{n+1} \right)^{\frac{n}{n+1}}
\]  

(7)

Where
\[ C_1 = \left[ \frac{372.25 g w_c (P_p - P_i)}{K} \right]^{\frac{1}{n}} \left( 0.5w_c \right) \left( \frac{1}{3 + n^{-1}} \right) \] (8)

After initiation of the second fracture, the propagating velocity of the first fracture is given by
\[ v_1 = C_1 \left( \frac{n+1}{n} x_0 \right) + \frac{n+1}{n} C(t) \] (9)

and the fluid flow rate in the first fracture is expressed as
\[ q_1 = h_f w_c v_1 = h_f w_c C_1 \left( \frac{n+1}{n} x_0 \right) + \frac{n+1}{n} C(t) \] (10)

The fluid injection rate into the second fracture is therefore
\[ q_2 = q_i - q_1 = q_i - h_f w_c C_1 \left( \frac{n+1}{n} x_0 \right) + \frac{n+1}{n} C(t) \] (11)

where is in ft3/s. The dynamic propagation length of the second fracture is given by
\[ x_2 = \left( \frac{2n+2}{2n+1} C_2 \right)^{\frac{2n+1}{2n+2}} \] (12)

where
\[ C_2 = \left[ \frac{372.25 g q_2 (P_p - P_i)}{Kh_f} \right]^{\frac{1}{2n+1}} \left( \frac{0.5q_2}{(3+n^{-1})h_f} \right) \] (13)

The dynamic average width of the second fracture is expressed as
\[ w_2 = \frac{\left( \frac{2n+2}{2n+1} \right)^{\frac{2n+1}{2n+2}} C_2}{h_f} q_2 \] (14)

When the width of the second fracture reaches the critical value \( w_c \), the rock stress at the initiation point of the fractures should cause rock failure and initiation of the third fracture. The critical time is expressed as
\[ t_{c2} = \left[ \frac{w_c h_f}{q_2 \left( \frac{2n+2}{2n+1} \right)^{\frac{2n+1}{2n+2}} C_2} \right] \] (15)

The critical length of the second fracture at the critical time is given by
\[ x_{q2} = \left( \frac{2n+2}{2n+1} \right) C_2 \left( \frac{2n+1}{2n+2} \right) \left( \frac{2n+1}{t_{c2}} \right)^{n+1} \]  

(16)

At the critical time for the second fracture, the length of the first fracture is expressed as

\[ X_1 = \left( \frac{n+1}{x_{q1}} + \frac{n+1}{n} C_1 t_{c2} \right)^{n+1} \]  

(17)

In general, for the \( k \)th fracture, the full length is expressed as

\[ x_{0k} = \left( \frac{2n+2}{2n+1} C_k \right) \left( \frac{2n+1}{2n+2} \right) \left( \frac{2n+1}{t_{ck}} \right)^{n+1} \]  

(18)

where

\[ C_k = \left[ \frac{372.25 g q_k (P_p - P_f)}{K h_f} \right]^{1/2n+1} \left[ \frac{0.5 q_k}{(3 + n^{-1}) h_f} \right]^{n/2n+1} \]  

(19)

and

\[ t_{ck} = \left[ \frac{w_i h_f}{q_k \left( \frac{2n+2}{2n+1} \right) \left( \frac{2n+2}{2n+1} C_k \right)^{2n+2}} \right]^{2n+2} \]  

(20)

where

\[ q_k = \frac{q_i}{k} \]  

(21)

At time \( t \) the number of fractures is

\[ k = \frac{q_i}{x_{0k} w_i h_f} \]  

(22)

The procedure for computing the propagation distance \( x_{0k} \) and the critical time \( t_{ck} \) for the \( k \)th fracture is to solve Eqs. (18) through (22) numerically. Then sum up all the critical times to get the corresponding total injection time.

3. MODEL ANALYSIS

The analytical model for vertical fractures was coded in a computer program to get instant numerical solutions. A sensitivity analysis was run with the computer program to identify engineering factors affecting the sequential initiation and simultaneous propagation of multiple fractures in the SRV. Table 1 presents basic data for the analysis.
Table 1. Data Set Used in Sensitivity Analysis

| Parameter                                      | Value       |
|-----------------------------------------------|-------------|
| Flow rate into one side of perforation cluster (qi) | 7.5; 10 bpm |
| Pressure in perforation cluster (Pp)          | 5500 psi    |
| Pressure at fracture tip (Pt)                 | 5000 psi    |
| Overall density of fracturing fluid (ρL)      | 165.36 lbm/ft³ |
| Fracture height (hf)                          | 100 ft      |
| Flow consistency (K)                          | 1 cp        |
| Fluid behavior index (n)                      | 1; 1.1      |
| Critical fracture width (wc)                  | 0.033 inch  |

Tables 2 summarizes model-calculated number of fractures and fracture length. Figure 1 illustrates fracture sketches plotted with the data in Table 2. The fractures are drawn in scale in the vertical axis (the direction of the maximum horizontal stress) and no-scale in the horizontal axis. These figures imply that the fractures grow and spread out with time not following a linear order. Figure 2 shows a comparison of two data sets with the same value of fluid flow behavior index, indicating that shorter fractures can be created by higher fluid injection rates. Figure 3 presents a comparison of two data sets with the same fluid injection rate, indicating that shorter fractures can be created with higher value of fluid flow behavior index. The effects of injection rate and flow behavior index on the fracture length are due to the high friction pressures caused by the high-values of these two parameters, hindering the growth of large/long fractures. Figure 4 demonstrates the effect of flow rate on the number of fractures, indicating that more fractures can be created by higher fluid injection rates. Figure 5 presents the effect of flow rate on the number of fractures, indicating the more fractures can be created with higher value of fluid flow behavior index. The effects of injection rate and flow behavior index on the number of fractures are caused the limited intake of fluid by the long fractures due to high friction pressures.

Table 2. Model-computed propagation of fractures for qi=7.5 bpm and n = 1.1

| Injection Time (min) | Number of Fractures | Fracture Length (ft) |
|----------------------|----------------------|-----------------------|
| 0.9                  | 1                    | 136                   |
| 4.9                  | 2                    | 297                   |
| 13.9                 | 3                    | 455                   |
| 30.4                 | 4                    | 623                   |
| 56.3                 | 5                    | 793                   |
Figure 1. Fracture sketch drawn for $q_i = 7.5 \text{ bpm}$ and $n = 1.1$.

Figure 2. A comparison of two data sets with different fluid injection rates.
Figure 3. A comparison of two data sets different values of fluid flow behavior index.

Figure 4. Effect of injection rate on the number of fractures.

Figure 5. Effect flow behavior index on the number of fractures.
4. CONCLUSIONS

Analytical model was developed in this work to describe sequential initiation and simultaneous propagation of multiple vertical fractures in horizontal wells. This model is prepared designing frac-packing of gas hydrate reservoirs. Result of sensitivity analyses with the model allows for drawing the following conclusions. To frac-pack horizontal gas hydrate wells for solid production control, increasing injection rate of fracturing fluid will create more friction and thus more resistance to flow in large fractures, promoting the creation of more short fractures, and thus larger treated reservoir volume (TRV) for higher gas production rate and gas recovery. Using dilatant fracturing fluid (n > 1) will cause more friction and thus more resistance to flow in large fractures owing to the shear-thickening property of the fluid. This will promote the creation of more short fractures and thus larger treated reservoir volume (TRV) for higher gas production rate and gas recovery.

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