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Insights Into Hydraulic Fracturing of a Horizontal Well in a Naturally Fractured Formation

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Horizontal wells are thought to be necessary in formations with low-permeability such as the Devonian shales to increase natural gas recovery and to reduce the risk of drilling a dry hole. In a horizontal well, the bore hole crosses multiple natural fractures in the reservoir. Stimulation data from a 2,000 ft (609.6 m) horizontal well drilled into the Devonian shales in Wayne County, West Virginia, was used in this study. Inflatable packers and casing port collars were used so that individual zones could be tested or stimulated along the wellbore.

This paper focuses on an analysis of hydraulic fracture design and geometry predictions for the above horizontal well. Current hydraulic fracture modeling theories address failure mechanisms and the propagation of a single crack from a vertical wellbore. These theories have been adapted to predict the pressure, flow rate, and induced fracture geometry for each natural fracture intersected by the hydraulic fracturing fluid in the horizontal wellbore. A tubing/annulus flow model was coupled with a hydraulic fracture model that predicts the three-dimensional geometry of multiple natural fractures propagating from a horizontal well. Additionally, a closed-form solution was developed to predict the pressure and flow rate distribution along the lateral extent of the wellbore.

Predicted results were compared with in situ fracture diagnostics from gas (nitrogen and CO_2) and foam stimulation treatments. Radioactive-tracer with spectral-gamma-ray logging confirmed that both fluid pressure and stress perpendicular to the fracture affect the injection flow rate distribution along the wellbore. Both of these factors were used as governing mechanisms for fracture geometry predictions in the simulation model. Predictions based on these models and tracer logs confirm that the single crack theory for fracture propagation is not applicable for stimulations that are initiated along an isolated part of a horizontal borehole.

References and illustrations at end of paper.

BACKGROUND

Recent investigations at the U.S. Department of Energy's Morgantown Energy Technology Center have addressed the potential of horizontal wells to increase the gas recovery from low-permeability formations. A 2000 ft (609.6 m) horizontal well was drilled into the Devonian shale formation in Wayne County, West Virginia, to a measured length of 6,020 ft (1,835 m) and up to a true vertical depth of 3,403 ft (1,037 m).

A schematic of the well configuration is shown in Figure 1. The fracture spacing and locations of casing packers were determined with a downhole video camera and geophysical well logs. Seven zones were isolated along the horizontal section, with external casing packers and port collars as part of the casing string. The port collars and packers were used to isolate stimulation intervals with existing perforations. Fracturing fluids were injected through the port collars into the wellbore tubing and annulus to pressurize the natural fracture system. Stimulations were performed in Zone 1 (see Figure 2) with nitrogen, carbon dioxide, and sand-laden nitrogen foam to determine the most effective fracturing fluid for the shale formation.

INTRODUCTION

The objective of this study on a horizontal wellbore was to determine the recovery effectiveness of the natural fracture system and the impact of stimulating the well by hydraulic fracturing. Five stimulations have been performed. Multiple fractures were propagated simultaneously during these stimulation treatments. The well was drilled in the direction of the minimum principal stress and orthogonal to the major fracture system in the reservoir. Six natural fracture orientations were identified with the downhole video camera and geophysical well logs.[1] Figure 2 depicts the natural fracture pattern and orientations in Zone 1. When high-pressure fluid was pumped down the tubing and annulus of the well, numerous natural fractures were enlarged. Actual breakdown of the shale may not have occurred, but fluid leak-off and subsequent expansion of the existing fracture system took place. The objectives of the treatments were (1) to induce multiple hydraulic fractures, (2) to determine their number and location, (3) to identify the most effective treatment design, and (4) to investigate the influence of propping agents on fracture efficiency in a low stress area.

Field experiments determined the effects of fluid type, injection rate, fluid volume, and bottom-hole treating pressure on stimulation performance. Several stimulation issues were investigated: (1) the number of natural fractures that can be propagated simultaneously, (2) the need for a proppant to sustain high conductivity after stimulation, (3) the impact of fracture characteristics on fluid interaction and propagation, and (4) the selection of the best fracture diagnostic system to detect fluid loss along the wellbore casing.

The field experiments indicated that the most effective fracture design consisted of a hybrid treatment with a carbon dioxide pad and a high quality nitrogen foam as the sand transport fluid. This prevented screenout and formation damage while maintaining post-stimulation fracture conductivity.

This paper focuses on the prediction of multiple fracture geometries with two hydraulic fracture models that have been adapted for a horizontal well. Measured data from two of the stimulations performed in Zone 1 were used to compute fluid flow and pressure distributions along the wellbore. Fracture geometries were predicted with these boundary conditions at the wellbore. These predictions provide insight into the performance of a hydraulic fracturing treatment in a horizontal well, and these predictions could be used in future stimulation designs.

METHODOLOGY

Data Evaluation

Four primary sets of data are required to predict the geometry of a single, planar, hydraulic fracture in a vertical well: (1) fluid type, injection volume, and rate; (2) rock mechanical properties; (3) proppant characteristics and treatment schedule; and (4) reservoir properties. Additional data sets are necessary to predict the fracture geometry in a horizontal well: (1) the number of natural fractures accepting fluid; and (2) natural fracture characteristics such as orientation, extent, spacing, and vertical displacement between each fracture. Mechanical and formation flow properties used in the present prediction are given in Table 1. The formation properties were measured from well core samples,[1] and the mechanical properties of the shale are typical measured values for Devonian shales. The fluid rheological properties were taken from available literature.[2,3]

Stimulation Treatment I

Documentation of the stimulations of this horizontal well can be found in Reference 4. A total of three stimulation treatments were performed in Zone 1. Two of these utilized carbon dioxide while one used only nitrogen gas without a propping agent. Predictions for two of the stimulations are presented in this paper. Stimulation I consisted of 120 tons (108,862 kg) of liquid carbon dioxide injected down the 4.5-in (11.53 cm) casing with an annulus of 2.2-in (5.59 cm) tubing.

During the injection at 12 barrels per minute (bpm) (1.92 m^3pm), Iodine-131 isotope tracer was included while Scandium-46 isotope tracer was included during the higher injection rate of 20 bpm (3.20 m^3pm). The maximum surface pressure was 2,642 psi (18,216 kPa), when the injection rate reached 20.7 bpm (3.31 m^3pm). The first 200 bbl (31.79 m^3) of liquid carbon dioxide were injected at 12 bpm (1.92 m^3pm), while the last 400 bbl (63.59 m^3) were injected at a rate of 20 bpm (3.2 m^3pm). The well was opened to flow back 5 hours after the job was completed. The recorded treatment rates and bottom-hole pressures for Stimulation I are shown in Figures 3 and 4.

Stimulation Treatment II

Stimulation II consisted of a hybrid treatment: a carbon dioxide pad followed by a sand-laden, 85-quality, nitrogen foam treatment where the liquid phase consisted of 7.5 percent methanol and water. The hybrid treatment was selected since results of previous stimulations indicated that carbon dioxide is the preferred base fluid for this shale formation. Since information on the sand carrying characteristics of carbon dioxide foam is sparse, nitrogen foam was used as the proppant transport fluid. The injection rates and computed bottom-hole pressure for Stimulation II are shown in Figures 5 and 6. Phase I consisted of 119 bbl (450.5 ℓ) of a carbon dioxide prepad that was pumped at a rate of 3 bpm (.48 m^3pm). Phase II consisted of 7,000 gal (26,498 ℓ) of an 85-quality nitrogen foam pad injected at 10 bpm (1.6 m^3pm), and Phase III consisted of four stages of 85-quality nitrogen foam laden with 0.5 to 2.0 lb/gal (.06 Kg/ℓ to .24 Kg/ℓ) of 20/40 mesh sand. The well started taking fluid at 770 psi (5,309 kPa) and the surface pressure increased slowly to a maximum of 1,850 psi (12,755 kPa). Two radioactive tracers were used. Antimony-124 was injected into the foam pad and Iridium-192 pellets were injected into the proppant. A spectral gamma ray tool was pumped down with nitrogen in the air-filled horizontal wellbore to measure the tracer distribution along the casing annulus.

Characteristics of Natural Fractures

Fracture characteristics required to predict the geometries are depicted in Figure 2 and listed in Table 2. Fracture spacing is indicated as the measured distance between groups of natural fractures. Vertical displacement, which is indicated as Δh, is the change in wellbore depth between discrete fractures. The range in orientation of fractures for this well is N22°E to N44°W with N52°E being the direction of maximum principal horizontal stress in the reservoir, or the preferred orientation for an induced vertical hydrofracture. In Zone 1, the primary groups of fractures consisted of N57°E and N67°E orientations. These two sets have the lowest values of direct normal stresses compared to other orientations in the zone, and these sets accepted most of the fluid during both Stimulations I and II. The direct normal stresses were calculated for each fracture orientation and are shown in Table 2. These values were calculated with data from a minifracture treatment performed on Zone 6. During this minifrac, two distinct closure or minimum stress measurements were observed from pressure decline curves. These values were 1,050 and 800 psi (7,239.5 and 5,515.8 kPa). The two dominant fracture systems in this zone are N67°E and a probable intersection of N44°W from Zone 7. A direct stress of 1,050 psi (7,239.5 kPa) was assumed for N44°W, and 800 psi (5,515.8 kPa) was assumed for N67°E. A stress transformation was used to back calculate the maximum and minimum principal stresses and direct normal stresses for other orientations.

Tracer Log Results

Spectral gamma ray logging was used to qualitatively measure the amounts of tracer-laden fluids and proppant injected into selected fractures along the wellbore.[4] The tracer log from Stimulation I is shown in Figure 7. Tracer logs indicated that during the first phase of the stimulation, fluids propagated into Fracture System I (Figure 2) and entered the fault system that intersects Zone 4. A tracer was detected in Zone 4 from this phase of pumping. Fluids penetrated Fracture System II (Figure 2) during Phase II when the injection rate and pressures were increased. The tracer log indicated that 51 of the 69 fractures present in Zone 1 accepted fluid during Stimulation I. During Phase II, fluids penetrated Fracture System II and traveled back to the wellbore as evidenced by the scandium that was detected in Zone 2. This indicates that a highly connected fracture system exists in the reservoir, and this system promotes multiple paths of expanded natural fractures from a single stimulation treatment.

The tracer log from Stimulation II appears to be similar to that from Stimulation I. Evaluation of the log indicates that 43 old fractures that accepted fluid during Stimulation I were re-opened and propped. Six of the 43 received the majority of the proppant.

These logs were used as fracture diagnostics to identify the relative amount of fluid that entered each fracture. Two forms of fluid entrance were identified on the basis of tracer logs: (1) annulus leak-off, and (2) large injection flow into discrete fractures. Leak-off is defined as a small amount of fluid that does not penetrate or significantly deform the formation. Large injection flow is defined as a significant rate of fluid penetration that is capable of carrying a proppant and inflating existing fractures to enhance reservoir permeability. The large injection fractures identified in Figure 7 correspond to the peaks on the tracer logs. The intermediate low level peaks located between the high peaks are considered to be leak-off locations. This flow into the formation is not considered as significant when compared with the large injections into discrete fractures. The large injection flows were computed and used to predict induced fracture geometries.

GOVERNING EQUATIONS

A schematic of the wellbore and fracture geometry is shown in Figure 8. During the hydraulic fracturing process, treatment fluids are pumped down the tubing and into the wellbore casing annulus through the port collar. This exposes the natural fractures to the high-pressure fluid, which initiates the propagation of the fluid front down the fractures. Because of pressurization in the annulus, the fractures subsequently expand (fracture growth occurs). Usually, the pressure and the flow rate at the port collars are known. However, the flow rate (injection rate) and pressure at each discrete fracture is not known. These values are required to predict the geometry of induced fractures. In this investigation, two methods were used to compute pressure and flow rates at each fracture location. In the first method, the fracture injection rate, fracture pressure, and flow rate downstream of each fracture were computed numerically using an iterative scheme. In the second method, the problem was simplified and a closed-form solution was obtained. Results from both methods were then compared with available field measurements.

Method I: Iterative Scheme

A pseudo three-dimensional (P3D) fracture model[5] was used in the iterative scheme for computing fracture pressures and injection rates. The relationship between fracture injection rate and wellbore pressures for a P3D approximation can be written as

$$Q_2(x,t) = \int_{-h}^{h} [(B)^r \, w^{2+r} \, (\frac{\partial p}{\partial x})^r] \, dy \quad , \qquad (1)$$

where: $\frac{1}{B} = \frac{16}{3\pi} k' \, (2 + r)^{n'} \, (2)^{n'+1} \qquad r \pm 1/n'$,

h = Half fracture height,

$\frac{\partial p}{\partial x}$ = Fracture pressure gradient,

n' = Fluid behavior index, and

k' = Fluid consistency index.

$\frac{\partial p}{\partial x}$ is the pressure gradient in the x-direction, and w is the fracture width. The value $Q_2(x,t)$ is the fluid injection rate into the natural fracture located at distance x from the port collar (Figure 8). The governing equation for the three-dimensional fracture flow model[6] can be expressed as

$$\bar{Q}_2 = -n'^{-\frac{1}{m}} \, w^{\frac{2m+1}{m}} \, [(\frac{\partial p}{\partial x} - f_1)^2 + (\frac{\partial p}{\partial x_2} - f_2)^2]^{\frac{(1-m)}{2m}} \quad , \qquad (2)$$

where: $n' = n_o (\frac{2m+1}{m})^m \, 2^{m+1}$,

w = fracture width,

$\frac{\partial p}{\partial x_1}$ = pressure gradient in x-direction,

$\frac{\partial p}{\partial x_2}$ = pressure gradient in y-direction,

n_o = fluid consistency index,

m = fluid behavior index, and

f = gravitational body force.

The fluid friction loss is computed assuming turbulent flow in a wellbore annulus with the Crittendon hydraulic diameter and Serghides friction factor. These equations have been statistically analyzed and determined to be the best correlations for Bingham Plastic annular fluid flow.[7] The friction loss and the Crittendon hydraulic diameter can be written as

$$d_e = 0.5\,[do^4 - di^4 - (do^4 - di^2)^2/\ell(do/di)]^{1/4} + 0.5\,[do^2 - di^2]^{1/2} \quad , \tag{3}$$

The Serghides friction factor and pressure drop equation is[7]

$$P_f = f\,\rho\,V^2L/25.8\,d_e \quad , \tag{4}$$

By considering the conservation of energy, the pressure distribution along the wellbore annulus can be expressed as

$$\frac{P_1}{\rho} + \frac{V_1^2}{2g} + z_1 = \frac{P_2}{\rho} + \frac{V_2^2}{2g} + z_2 + \frac{P_f}{\rho} \quad , \tag{5}$$

where: P = Pressure,

ρ = Fluid density,

V = Fluid velocity,

z = Well bore elevation at a given point,

g = Gravitational constant,

P_f = Pipe friction loss, and

d_e = Hydraulic diameter of the wellbore.

The continuity equation for fluid flow within a discrete fracture can be written as

$$Q_1 = Q_2 + Q_3 \quad , \tag{6}$$

This equation can be written for each fracture to obtain the relationship between the flow rate upstream to downstream flow rate in a discrete fracture. The total fluid entering the system must be equal to the fluid loss and the total amount of fluid taken up by all discrete fractures. This can be written as

$$Q_p = Q_\ell + \sum_{i=1}^{N} \bar{Q}_i \quad , \tag{7}$$

where: Q_p = Flow rate at the port collar,

Q_ℓ = Fluid flow into the formation,

$\bar{Q}_i$ = Fluid taken by "i"th fracture, and

N = Total number of discrete fractures.

An acceptable solution to the problem must satisfy all of the above equations. The acceptable solution in this case was obtained by using the trial and error scheme described below:

- Two hydraulic fracture models were used to predict the fracture geometry from Stimulation I, Phase II, and Stimulation II: the P3D and the 3D models provided the fracture pressure and injection rate relationships given by Equations 1 and 2.
- The models utilize fluid pressure and total injection rate at the port collar to compute downstream pressures and injection rates at selected fractures with a high flow rate. Filtration leak-off along the annulus was computed using the filtration leak-off formulation presented by Howard and Fast.[8]
- The hydraulic diameter of the annulus was assumed to be the slot width; the length of the pipe between fractures was assumed to be the leak-off distance. These two dimensions were used to compute the annulus leak-off area and volume.
- Pressure was calculated at the first selected fracture downstream of the port collar using Equations 2 and 3. This pressure was then matched with the pressure predicted by the existing fracture model by varying the flow rate while keeping other variables constant.
- The continuity and energy equations were then used to compute flow rate and pressure at the next downstream fracture. The pressure/flow rate matching procedure was continued until iterations were performed for all selected fractures.
- The total flow rate was then computed by adding the leak-off and fracture flow (Equation 7) for all selected fractures. If the difference between the actual injection rate and the computed rate was not within the desired tolerance, the matching procedure was repeated for the same time step until flow rate convergence (±1 bpm, ± .16 m^{3}pm) was obtained.
- The overburden and underburden stress magnitudes were adjusted and equal for all fractures to obtain convergence. These values are considered as a logical choice when matching flow rates and pressures. The procedure was repeated for each selected time step over the entire treatment period.

Method 2: Closed-Form Solution

A simplified procedure for computing pressure along the wellbore is presented. This method is based on the assumption that the system of discrete fractures can be replaced by an equivalent leak-off system as depicted in Figure 9. The frictional loss over a segment of dx can be expressed as

$$df_x = \alpha_1 \cdot V_p\,dx \quad , \tag{8}$$

where: $\alpha_1 = 32\,\frac{\mu}{\rho}\,\frac{1}{gD^2}$,

and μ = Fluid viscosity,

ρ = Fluid density, and

V_p = Pipe flow velocity at point x.

The above equation is the well-known Hagen-Poiseuille equation for laminar flow. It can easily be modified to account for turbulent flow by selecting an appropriate value for α_1. Since the fluid is lost to natural fracture along the pipe, the velocity $V_L(x)$ is a function of the coordinate x. The total frictional loss up to a distance of x can be expressed by integrating the above equation as

$$f_x = \alpha_1 \int_o^x V_p(x)\, dx \quad , \tag{9}$$

The leak-off velocity $V_L(x)$ is assumed to take the following form:

$$V_L(x) = \frac{C_1}{\sqrt{t}} \quad , \tag{10}$$

and $C_1 = \beta P + \gamma$,

where: β and γ = constants, and

P = Pressure at any given point.

Then, the continuity equation at any given point can be written as

$$V_p(x) = (\frac{4}{\pi D^2})\ (\bar{Q}) - (\frac{4}{\pi D^2})\ Q_{Lx} \quad , \tag{11}$$

where $\bar{Q}$ is the flow rate at the port collar, and Q(x) is the total fluid loss up to the point of interest. This can be expressed as

$$Q_{Lx} = \pi D \int_o^x V_L(x)\, dx \quad , \tag{12}$$

The fluid pressure, P(x), at a distance x can be written as

$$P(x) = P_1 - f_x \quad , \tag{13}$$

where P_1 is the pressure at the port collar. The combination of Equations (8) through (13) leads to the following second-order differential equation

$$\frac{d^2}{dx^2} P(x) - \frac{4\ \alpha_1}{D\sqrt{t}} P(x) = \frac{4\ \alpha_1\ \gamma}{D\sqrt{t}} \quad , \tag{14}$$

Applying the pressure boundary conditions at x = 0 and x = L, the following solution for pressure distribution can be obtained:

$$P(x) = Ae^{C_2 x} + Be^{-C_2 x} + \gamma \quad , \tag{15}$$

where: $$B = \frac{(P_1 - \gamma)\ e^{C_2 L} - (P_L - \gamma)}{e^{C_2 L} - e^{-C_2 L}} \tag{16a}$$

$$A = (P_1 - \gamma) - B \quad , \tag{16b}$$

$$C_2^2 = \frac{4\ \alpha_1}{D\sqrt{t}} \quad , \text{ and} \tag{16c}$$

P = Pressure at the end of the pipe, which is assumed to be slightly higher than the in situ stress.

RESULTS AND DISCUSSION

As indicated in the preceding section, pseudo three-dimensional (P3D) and three-dimensional (3D) models were used to predict the fracture geometries of selected fractures from Phase II of Stimulation I and all phases of Stimulation II. The horizontal well was located 30 ft (9.2 m) above the lower boundary of the shale layer, and hence, a stress barrier was assumed at the level of 30 ft (9.2 m) below the wellbore.

Based on recent reservoir studies,[9] it has been reported that the equivalent (effective) thickness of the reservoir was only 50 ft (15.3 m). However, the actual thickness of the shale layer was found as 200 ft (61.5 m). Since the P3D models are suitable only for elongated fractures, the effective thickness of 50 ft (15.3 m) was assumed in the P3D model. In other words, the upper stress barrier was assumed at 20 ft (6.1 m) above the wellbore in the case of the P3D model.

The three-dimensional model is capable of predicting the actual geometry of the fractures, hence, the actual (or physical) value was used for the reservoir thickness. Therefore, the upper stress barrier was assumed at a height of 170 ft (52.3 m) above the wellbore.

Predicted injection rates, fracture pressures, and equivalent fracture winglengths for three of the eight selected fractures (Figure 7) obtained from the P3D model for Stimulation I are given in Figures 10 through 12. The pressures predicted with the closed-form solution are presented in Figure 11. Figures 13 through 15 show similar results for Stimulation I with the 3D model predictions.

Results for Stimulation II are presented in Figures 16 through 19. The bottom-hole pressure was calculated for Stimulation II since only surface pressures were measured. Changes in proppant concentrations were taken into account. Figure 6 indicates that pressures continued to rise while injection rates were held constant. This is attributed to the increase in proppant concentration. Fluid viscosity corresponding to the increase in proppant concentration was increased over time to match the pressure profile.

The results of the P3D modeling indicate that some containment occurred during the treatments, and this containment promoted extensive fluid penetration throughout the fracture network. Thus, it is probable that highly elongated equivalent fractures were induced through more than a single natural fracture orientation. An equivalent fracture has the same fracture volume extended into the reservoir and does not follow a single orientation of maximum principal stress. For

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