Research Article

Well Screen and Optimal Time of Refracturing: A Barnett Shale Well

Shayan Tavassoli,¹ Wei Yu,¹ Farzam Javadpour,² and Kamy Sepehrnoori¹

¹ Department of Petroleum and Geosystems Engineering, The University of Texas at Austin, Austin, TX 78712, USA

² Bureau of Economic Geology, Jackson School of Geosciences, The University of Texas at Austin, Austin, TX 78713, USA

Correspondence should be addressed to Farzam Javadpour; farzam.javadpour@beg.utexas.edu

Received 30 January 2013; Accepted 1 April 2013

Academic Editor: Jorge Ancheyta

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Gas-production decline in hydraulically fractured wells in shale formations necessitates refracturing. However, the vast number of wells in a field makes selection of the right well challenging. Additionally, the success of a refracturing job depends on the time to refracture a shale-gas well during its production life. In this paper we present a numerical simulation approach to development of a methodology for screening a well and to determine the optimal time of refracturing. We implemented our methodology for a well in the Barnett Shale, where we had access to data. The success of a refracturing job depends on reservoir characteristics and the initial induced fracture network. Systematic sensitivity analyses were performed so that the characteristics of a shale-gas horizontal well could be specified as to the possibility of its candidacy for a successful refracturing job. Different refracturing scenarios must be studied in detail so that the optimal design might be determined. Given the studied trends and implications for a production indicator, the optimal time for refracturing can then be suggested for the studied well. Numerical-simulation results indicate significant improvement (on the order of 30%) in estimated ultimate recovery (EUR) after refracturing, given presented screen criteria and optimal-time selection.

1. Introduction

Shale-gas resources, predominantly lithified clays with low permeability [1], are considered unconventional gas reservoirs and important resources for the United States. However, gas production from these low-permeability resources is much greater than what is anticipated owing to non-Darcy flows and different sources of gas in their formations [2]. Gas flow is sourced from stored gas in nanopore networks and adsorbed gas on organic materials in the shale formations. However, new techniques are required for access to and economical production from these resources.

Recent advances in hydraulic-fracturing techniques have resulted in economic production from shale-gas reservoirs. Effective fracturing techniques make for successful economic production from extremely low (on the order of nanodarcies) permeability formations because they create a large,

stimulated reservoir volume [3, 4]. Such a success would be attributed to the potential for developing complex fracture networks, which could significantly improve reservoir-wellbore connectivity. Refracturing is a process of improving production rates and ultimate recovery, which is an economical alternative to infill drilling. Although refracturing seems an excellent method of significantly increasing gas production, only 15% to 20% of refractured wells achieve any desired improvement in practice [5–7]. Therefore, a reliable and systematic approach is critical to an increase in the success of refracturing jobs. Several published works [8–11] have suggested a selection of methodologies for finding good shale-gas-well candidates for refracturing. However, application of these methods is limited, and results are unsatisfactory in horizontal-well or complex-fracture-network cases or when adequate completion and reservoir/geology data sets are lacking. With the aid of numerical-simulation methods,

however, we are now able to study well performance properly by considering the presence of a complex fracture network, a tight matrix, and initial hydraulic fractures.

Field results demonstrate that refracturing success can be attributed to different parameters, such as the existing fracture network and reservoir properties, and a successful refracturing job should increase reservoir-wellbore connectivity, which is associated with further opening, extension, and reorientation of existing fractures. Reorientation is generally perpendicular to an initial hydraulic fracture as the result of minimum and maximum stress reversal, which occurs if induced stress changes are large enough to overcome the effect of initial horizontal stress [12]. Such a reversal could be the result of the stress created by the opening of an adjacent fracture or pore-pressure alteration due to previous production periods [13–15]. In such cases, the fracture network propagates, and, as a result, a larger portion of the reservoir is stimulated, subsequently increasing gas production and ultimate recovery.

Owing to the complexity of fracture growth in many shale-gas reservoirs, accurate prediction of fracture propagation is impossible; therefore, conductivity of the fracture network and the effectiveness of stimulation treatment are difficult to predict [16, 17]. Detailed numerical reservoir modeling is thus needed for us to better understand the mechanisms that control production in shale-gas reservoirs and to improve completion strategies and stimulation designs. First, we needed to validate our simulation model by modeling initial fractures and the refracturing process in a horizontal well in the Barnett Shale formation. Second, on the basis of our simulation model, we performed a sensitivity study on the effect of different parameters on refracturing performance. Sensitivity analyses provide insights into the dependency of the refracturing-process performance on corresponding parameters. The result would be helpful for selecting candidates for successful refracturing. We also compared results of the refracturing performance with closely spaced initial fracturing as an alternative to increasing gas recovery from the early stages of production. Note that specifying the optimal time of refracturing is crucial to maximizing performance of the process. Simulation results of refracturing at different stages of production suggest calculation of the optimal time on the basis of gas flow rate or cumulative gas-production recovery.

2. Methodology

Numerical simulation is a promising method in any design or well-performance evaluation and is commonly used to predict gas production. Specifically this approach has increased in importance for shale-gas reservoirs owing to the complexity of fracture networks and the low permeability of the formations because numerical simulations are capable of modeling fracture networks. Note that fracture-network complexity and conductivity control well productivity in shale-gas reservoirs—the more complex the fracture networks (i.e., the smaller the blocks or the denser the fracture spacing), the higher the production rates [18, 19]. Fracture

networks should therefore be considered in the simulation of the refracturing process, even though their initial network fracture conductivity may be relatively low (e.g., in the Barnett Shale, it ranges from 0.5 to 5 md-ft) [18, 20].

Development of numerical simulation approaches that can properly model fluid flow in tight formations and that are capable of capturing complex fracture networks and initial hydraulic fractures is important in an evaluation of well performance and an explanation of properties that affect gas recovery. Gas flow from ultralow-permeability rock through complex fracture networks must be modeled so that stimulation designs and completion strategies can be properly evaluated. Therefore, the complex fracture network and initial hydraulic fractures must be discretely characterized in these reservoir-simulation models.

We validated our simulation methodology using field data from a refractured horizontal well in the Barnett Shale formation. We selected the Barnett Shale because of the availability of production data and because, so that economically viable production rates might be attained, hydraulic-fracture stimulation is a necessity in this formation.

The simulation model is based on a dual permeability model for two-phase (gas-water) fluid flow. Such a model considers the communication between the intergranular void spaces in contrast to the dual porosity model, which neglects this communication. The dual permeability model considers flow in the two domains of matrix and fracture, whereas the dual porosity approach assumes two domains with different hydraulic and transport properties [21]. The dual permeability model allows for simulations involving gas and water transfer between the fracture and matrix domains. Gas flow velocities in matrix and fracture are calculated on the basis of (1) and (2), respectively,

$$v_g^m = - \left(\frac{K_g^m}{\mu_g} \nabla p_g + \frac{D_g^m}{C_g^m} \nabla C_g^m \right), \quad (1)$$

$$v_g^f = - \left(\frac{K_g^f}{\mu_g} \nabla p_g + \frac{D_g^f}{C_g^f} \nabla C_g^f \right), \quad (2)$$

where v_g is gas velocity, K_g is gas permeability, D_g is gas diffusivity, P_g is gas pressure, C_g is gas concentration, and μ_g is gas viscosity. Superscripts m and f represent matrix and fracture, respectively. Water-flow velocities in matrix and fracture are calculated on the basis of (3) and (4), respectively,

$$v_w^m = - \frac{K_w^m}{\mu_w} \nabla p_w, \quad (3)$$

$$v_w^f = - \frac{K_w^f}{\mu_w} \nabla p_w, \quad (4)$$

where v_w is water velocity, K_w is water permeability, P_w is water pressure, and μ_w is water viscosity. The equations are thus simplified to represent gas flux in matrix:

$$\frac{\partial}{\partial t} \left(\frac{C_g^m P_g^m}{Z} \right) = \nabla \left(\frac{P_g^m}{Z} \frac{K_g^m}{\mu_g} \nabla P_g^m + D_g^m \nabla \frac{P_g^m}{Z} + \frac{D_g^m}{C_g^m} \frac{P_g^m}{Z} \nabla C_g^m \right) - \frac{RT}{M} (q_g^{mf} + q_g^m), \quad (5)$$

where Z is the gas compressibility factor, R is the gas constant, T is temperature, M is gas molecular weight, and q_g is gas mass-flow rate per unit matrix-block volume. Superscript mf represents the exchange between matrix and fracture. We can also write this equation for the aqueous phase in matrix as

$$\frac{\partial}{\partial t} \left(\frac{\phi_m s_w^m}{B_w} \right) = \nabla \left(\frac{K_w^m}{B_w \mu_w} \nabla P_w^m \right) - \frac{RT}{M} (q_w^{mf} + q_w^m), \quad (6)$$

where ϕ_m is matrix porosity, s_w is water saturation, and B_w is the water compressibility factor. As a result of simplification of the equations, gas flux in fracture becomes

$$\frac{\partial}{\partial t} \left(\frac{C_g^f P_g^f}{Z} \right) = \nabla \left(\frac{P_g^f}{Z} \frac{K_g^f}{\mu_g} \nabla P_g^f + D_g^f \nabla \frac{P_g^f}{Z} + \frac{D_g^f}{C_g^f} \frac{P_g^f}{Z} \nabla C_g^f \right) + \frac{RT}{M} (q_g^{mf} - q_g^f), \quad (7)$$

and also for water in fracture:

$$\frac{\partial}{\partial t} \left(\frac{\phi_f s_w^f}{B_w} \right) = \nabla \left(\frac{K_w^f}{B_w \mu_w} \nabla P_w^f \right) + \frac{RT}{M} (q_w^{mf} - q_w^f) \quad (8)$$

with auxiliary equations

$$\begin{aligned} C_g^m &= \phi_m s_g^m, \\ C_g^f &= \phi_f s_g^f, \\ s_g^m + s_w^m &= 1, \\ s_g^f + s_w^f &= 1. \end{aligned} \quad (9)$$

3. History Matching

The simulation results presented in this work are obtained mainly by using the Computer Modeling Group (CMG) model [22]. Our modifications and methodology of using this model are presented in Section 2. In order to validate our simulation model, we modeled initial fractures and the refracturing process in a horizontal well in the Barnett Shale formation. The Barnett Shale is a Mississippian-age marine shelf deposit having a formation thickness that varies from 200 to 800 ft through the reservoir and ultralow permeability in the range of 70–500 nanodarcies [23]. The selected well is a cased, uncemented well in the formation.

FIGURE 1: Comparison between simulation results and field data.

The well is located in the lower Barnett Shale and drilled northwest to maximize fracture-network formation. It has five equally spaced initial fractures covering a depth interval from 7,900 to 10,106 ft [23]. The well was refractured after more than 4 years in four stages in the middle of the initial fractures. Gas production from the well was monitored and plotted for its 6 years of production (4.5 years before and 1.5 years after refracturing) (Figure 1).

Input data used in the simulation model to predict gas production from the well appear in Table 1. Refracturing after 4 years of production significantly increased productivity of the horizontal well (Figure 1), and comparison of the simulation-model results and field data verifies that our model is capable of modeling initial fractures and refracturing.

Fractures postclosure occurs during production and depletion of any shale well, closure stress, and long-term degradation of proppants controlling the extent of fracture postclosure. Gas production may decrease owing to fracture-conductivity impairments, especially during later gas production. Yu and Sepehrnoori [24] recently studied the effect of reservoir depletion on fracture conductivity in the Barnett Shale. They showed that fracture conductivity reduces to about 40% of original conductivity at a limiting bottom-hole pressure of 500 psi. However, because of the great contrast between matrix permeability and fracture permeability in shale, fracture postclosure has a negligible effect (<2%) on gas production, even after 30 years [24]. This is especially true of formations with a high Young's modulus (6×10^6 psi to 10×10^6 psi), such as the Barnett Shale.

4. Results and Discussion

In this section we use our verified numerical model and the present gas production rate and cumulative gas production of the studied well. In our sensitivity analyses we present the effects of formation permeability and porosity, as well

TABLE 1: Input data used in simulation model.

Parameter	Value(s)	Unit: field (SI)
Model dimensions	5000 × 5000 × 300 (1524 × 1524 × 91)	ft (m)
Initial reservoir pressure	3800 (2.62 × 10 ⁷)	psi (pa)
BHP	1100 (7.58 × 10 ⁶)	psi (pa)
Production time	30	year
Reservoir temperature	150 (66)	°F (°C)
Gas viscosity	0.0201 (2.01 × 10 ⁻⁵)	cp (pa.s)
Initial gas saturation	0.70	fraction
Total compressibility	3 × 10 ⁻⁶ (4.35 × 10 ⁻¹⁰)	Psi ⁻¹ (pa ⁻¹)
Matrix permeability	5 × 10 ⁻⁴ (4.93 × 10 ⁻¹⁹)	md (m ²)
Matrix porosity	0.018	fraction
Fracture conductivity	1 (3 × 10 ⁻¹⁶)	md-ft (m ² -m)
Fracture half-length	Varied: Min = 470 (143), Max = 1870 (570)	ft (m)
Fracture spacing	550 (168)	ft (m)
Refracture half-length	970 (296)	ft (m)
Refracture spacing	275 (84)	ft (m)
Fracture height	300 (91)	ft (m)
Horizontal well length	2800 (853)	ft (m)
Number of fractures	5	number
Number of refractures	4	number

as initial induced hydraulic-fracture conductivity on well performance. These analyses are followed by a discussion on well-screening criteria and time optimization of refracturing. We used base data (Table 1) to create simulation cases by varying individual parameters for sensitivity analyses. Gas-production rate and cumulative gas production were plotted against time for all parameters to show the performance of the well. Each plot included well performance with and without refracturing to highlight refracturing effectiveness on gas-production performance.

4.1. Effects of Permeability. We created two plots to show the effects of formation permeability on gas flow rate and cumulative gas production rate (Figures 2 and 3). In each plot we considered two scenarios—performance of the well without refracturing and a case of refracturing after 4 years. Intuitively we knew that both gas flow rate and cumulative gas production would improve if permeability increased. The refractured wells showed better gas flow rates and 30% to 70% improvement in cumulative gas production for the highest (0.0005 md) and lowest (0.00005 md) permeabilities, respectively.

4.2. Effects of Porosity. We created two plots to show the effects of formation porosity on gas flow rate and cumulative gas production rate (Figures 4 and 5). In each plot we considered two scenarios—performance of the well without refracturing and a case of refracturing after 4 years. The refractured wells showed better gas flow rates and 50% to 70% improvement in cumulative gas production for the lowest (0.04) and highest (0.08) porosities, respectively.

FIGURE 2: Effects of formation permeability on gas flow rate. Two scenarios: no refracturing and refracturing after 4 years of production.

4.3. Effects of Initial Fracture Conductivity. We created two plots to show the effects of initial fracture conductivity on gas flow rate and cumulative gas production rate (Figures 6 and 7). In each plot we considered two scenarios—performance of the well without refracturing and a case of refracturing after

FIGURE 3: Effects of formation permeability on cumulative gas production. Two scenarios: no refracturing and refracturing after 4 years of production.

FIGURE 5: Effects of formation porosity on cumulative gas production. Two scenarios: no refracturing and refracturing after 4 years of production.

FIGURE 4: Effects of formation porosity on gas flow rate. Two scenarios: no refracturing and refracturing after 4 years of production.

4 years. Both gas-flow rate and cumulative gas production improved when initial fracture conductivity was increased. The refractured well showed better gas flow rates and 50% to 80% improvement in cumulative gas production for the highest (10 md-ft) and the lowest (0.1 md-ft) initial fracture conductivities, respectively.

4.4. Well Screen Criteria. Cumulative gas production and gas flow rate increase as reservoir permeability, porosity, and initial fracture conductivity increase (Figures 2–7). Because increase in the trends of gas production in these cases is significant in contrast to the increase in trends of gas flow rate, we are unable to refine our selection on the basis of these trends. We therefore compared our results on the basis of production indicators to select candidate shale-gas wells for refracturing. Given the correlation between monthly incremental and 5-year cumulative gas production, wells falling off the trend line indicate wells that had good initial production but for which longer-term recovery was poor [9] (Figure 8). Because all of our cases are located on the trend line, this method adds no information about range of selection.

To determine and compare production enhancement in each case study, we introduce a production indicator, known as *long-term refracturing efficiency* and defined as the ratio of cumulative gas production after refracturing to its value before refracturing in 30 years of production:

Long-term refracturing efficiency

$$= \frac{\text{Total cumulative gas production after refracturing}}{\text{Total cumulative gas production with no refracturing}} \quad (10)$$

We calculated and plotted long-term refracturing efficiency for each case and found that refracturing efficiency increases as reservoir permeability reduces to its lower limits (Figure 9). Efficiency enhancement is not that significant,

FIGURE 6: Effects of initial fracture conductivity on gas flow rate. Two scenarios: no refracturing and refracturing after 4 years of production.

however, at permeability values greater than 0.0001 millidarcy. Refracturing efficiency increases as porosity increases (Figure 10). Efficiency enhancement due to refracturing is significant when porosity values are greater than 6%. The difference in gas-production enhancement with respect to permeability might seem to be in contradiction to its trend with respect to porosity because of the correlation between permeability and porosity. However, note that refracturing enhances gas production from low-permeability reservoirs by forming a more complex fracture network that has been depleted from a larger stimulated reservoir volume (SRV). On the other hand, larger porosity corresponds to a larger amount of initial gas in place. Hence, refracturing enhancement cannot be responsible for an increase in gas production in cases with high-porosity values. We also studied the effect of initial fracture conductivity on the performance of refracturing. Refracturing efficiency increases as fracture conductivity decreases (Figure 11), efficiency enhancement increasing in significance for values lower than 1 md-ft. Results of these simulations reveal that long-term refracturing efficiency can provide insight into the effect of each parameter and its importance. On the basis of this sensitivity study we have proposed a screening method for existing fractured horizontal wells that is based on reservoir and initial hydraulic-fracture properties (Table 2).

4.5. Initial Fracture Spacing. Here we compare results of refracturing performance with that of closely spaced initial fracturing, which can be an alternative to increasing gas recovery beginning in the early stages of production. Different values of fracture spacing (50, 100, 200, 350, and 450 ft) are considered here. Refracturing in the middle of initial

FIGURE 7: Effects of initial fracture conductivity on cumulative gas production. Two scenarios: no refracturing and refracturing after 4 years of production.

FIGURE 8: Correlation between short-term and long-term production [9], along with our simulation results.

fractures is also performed in all the cases after 4 years of production, except in cases where initial fractures are close to one another (50 ft). The total number of fractures for each case is 57 (57 initial fractures), 57 (29 initial fractures and 28 refractures), 29 (15 initial fractures and 14 refractures), 17 (9 initial fractures and 8 refractures), and 13 (7 initial fractures and 6 refractures). Cumulative gas production from refractured wells having higher initial values of fracture spacing is similar to that of closely spaced initial fractures if the ultimate fracture spacing remains the same (Figure 12). In other words, we expect the same performance in the two cases having the same value of total fracture length, including

TABLE 2: Well screening criteria.

Property	Perfect selection	Fair selection	Poor selection	Unit: field (SI)
Permeability	$<0.0001 (9.8 \times 10^{-20})$	$<0.0005 (4.9 \times 10^{-19})$	$>0.0005 (4.9 \times 10^{-19})$	md (m ²)
Porosity	>0.06	>0.04	<0.04	fraction
Fracture conductivity	$>1 (3 \times 10^{-16})$	$<10 (3 \times 10^{-15})$	$>10 (3 \times 10^{-15})$	md-ft (m ² -m)

FIGURE 9: Long-term refracturing efficiency versus different permeabilities.

FIGURE 11: Long-term refracturing efficiency versus different fracture conductivities.

FIGURE 10: Long-term refracturing efficiency versus different porosities.

refractured lengths. Hence, refracturing at the proper time of production appears to be an attractive restimulation method for wells having large initial fracture spacing.

4.6. The Optimal Time to Refracture a Well. Finding the optimal time to refracture so as to maximize the performance of the refracturing job is crucial. On the basis of available field-production data of successful refracturing processes in Barnett Shale formations and the simulation results of different refracturing scenarios, we proposed an indicator for finding the proper time for refracturing.

To find the optimal time, we considered different times of refracturing. Cumulative gas production and gas flow rate

for these different cases are obtained from simulation results (Figures 13 and 14, resp.). Because of the difficulty involved in such a task, however, we studied trends in detail and proposed an indicator for comparison between various production trends.

The *proposed indicator* suggests that if the decline rate of gas production falls below 10% to 15%, the refracturing process should be applied. The cumulative gas production result of refracturing after 2 or 3 years of production is higher than that of a well refractured after 4 years of production (Figure 13). However, the incline rate of the cumulative gas production is still significant (more than 20%) (Figure 15). Hence, the decline rate of gas production is pronounced early in the stimulation process, but only until it reduces below 15%, at which point the initial stimulation effect has vanished and gas production levels off. Under these conditions, refracturing should be considered as a way to increase gas production from the well. Incline-decline rates can be defined as

$$\text{Decline rate of gas production} = \frac{q_r^{n-1} - q_r^n}{q_r^{n-1}},$$

$$\text{Incline rate of cumulative gas production} = \frac{Q^{n+1} - Q^n}{Q^n}, \quad (11)$$

where n is refracturing time in years, q_r is gas flow rate, and Q is cumulative gas production. Both decline rate of gas production and incline rate of cumulative gas production during the first 6 years of a project's life reduce over that time and level off (Figure 15). According to the introduced

FIGURE 12: Cumulative gas production for different fracture-spacing values.

indicator, the proper time for refracturing occurs after 4 years of production because the decline rate of gas production drops to less than 15% during that fourth year.

5. Conclusions

We used numerical simulation to study refracturing of wells in shale formations by selecting a well in the Barnett Shale formation and simulating gas production from this well. We used the verified model to perform sensitivity studies on formation properties and initial-fracture conductivity on gas-production performance. We found that refracturing is an effective restimulation technique if it is performed for a proper candidate well and at the optimal time. Numerical-simulation results indicate significant improvements on the order of 30% in estimated ultimate recovery (EUR) after refracturing. Some specific conclusions are as follows.

- (1) Our simulation model results suggest that refracturing is more effective in low-permeability reservoirs. Refracturing enhances gas production by forming a more complex fracture network and producing larger stimulated reservoir volume (SRV) in these low-permeability reservoirs. Larger porosities result in higher gas production owing to an increase in the amount of gas in place.
- (2) Results show that higher values of initial fracture conductivity eliminate the need for refracturing owing

FIGURE 13: Cumulative gas production for different times of refracturing.

FIGURE 14: Gas flow rate for different times of refracturing.

to the presence of conductive paths between wellbore and reservoir.

- (3) Refracturing performance was compared with that of closely spaced initial fractures. Results show that cumulative gas production correlates with total fracture length, including refracture lengths.
- (4) We developed a screening method for existing wells in a formation that was based on reservoir characteristics and initial hydraulic-fracture properties. The screening method provides perfect, fair, and poor selection categories that are based on ranges of the studied variables.

FIGURE 15: Decline rate of gas flow rate and in-line rate of cumulative gas production versus time.

- (5) Finding the optimal time for refracturing so as to maximize its performance is crucial. On the basis of detailed study of gas flow rate and cumulative gas production in the first 6 years of a project's life, we suggest performing refracturing at the point in the life of the project when decline of the gas flow rate falls below 10% to 15%.

Nomenclature

v :	Flow velocity, m/s
μ :	Viscosity, Pa·s
p :	Pressure, Pa
K :	Phase permeability, m^2
C :	Concentration, m^3/m^3
D :	Diffusivity, m^2/s
Z :	Gas-compressibility factor
ϕ :	Porosity
B :	Compressibility factor, Pa^{-1}
R :	Gas constant, $\text{Pa}\cdot\text{m}^3/(\text{mol}\cdot\text{K})$
M :	Molar mass, kg/mol
T :	Temperature, K
q :	Mass flow rate per unit matrix-block volume, $\text{kg}/(\text{m}^3\cdot\text{s})$
q_r :	Gas flow rate, MMSCF/D
Q :	Cumulative gas production, MMSCF
s :	Phase saturation.

Superscripts

m :	Matrix
f :	Fracture
mf :	Exchange between matrix and fracture.

Subscripts

g :	Gas
w :	Water.

Acknowledgments

The authors would like to thank Computer Modeling Group Ltd. for use of the CMG-IMEX software. They would also like to express their gratitude for financial support from the Hilcorp Energy Company and NanoGeosciences lab at the Bureau of Economic Geology (UT-Austin) and to thank Ms. L. Dieterich for editing the paper.

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