Effect of fracture design parameters on the well performance in a hydraulically fractured shale gas reservoir

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Abstract

This study investigates the impact of fracture design parameters from the results of sensitivity analysis in a shale gas reservoir. When a shale gas reservoir is hydraulically fractured, the fracture network systems are formed comprising primary and secondary fractures. In the case of low permeability reservoir, especially, the more complex fracture network systems is, the more the productivity is improved. In this study, a sensitivity analysis was carried out to evaluate the impact of fracture design parameters on the well performance in a hydraulically fractured shale gas reservoir using simulation model. The productivity is improved when the secondary fracture conductivity increases or spacing decreases with various conditions of reservoir. It is shown that the determination of whether to increase or decrease secondary fracture growth is required to improve the productivity of shale gas reservoir. Based on the results, a guideline for hydraulic fracturing is proposed.

Keywords: Shale gas, Fracture design parameter, Multistage fracturing of horizontal wells, Sensitivity analysis

1. INTRODUCTION

For successful development of the shale gas, it is necessary to maximize productivity by analyzing the flow characteristic and reservoir property and effective fracture treatment design which influence on well performance (Guo and Gao, 2014). The fracture design parameters are important to optimize the production of shale gas (Rahman *et al*., 2007). When a low-permeability reservoir is hydraulically fractured, a fracture network system is formed comprising primary and secondary fractures and it should be considered to understand the production performance of a shale gas reservoir (Cipolla *et al*., 2010).

Gilbert and Barree (2009) designed an analytic model to simulate the behavior of hydraulically fractured reservoir on the constant surface pressure. It is confirmed that determining the optimum number of treatments, spacing, and eventual completion efficiency is critical to the success of horizontal well development.

Novlesky *et al*. (2011) presented a workflow used in developing a numerical shale gas model for Nexen's Horn River shale gas reservoir. The workflow is given starting with parameter sensitivity analysis and history matching of multiple cases followed by uncertainty assessment.

Sahai *et al*. (2012) determined the optimal number of wells for infill drilling in a shale gas reservoir. The results of well optimization study initiated from a production performance analysis of over 100 wells in the Haynesville shale and 300 wells in the Marcellus shale. The results indicate a threshold of reservoir and completion properties below which well drilled may be uneconomic based on the financial assumptions. In addition, the optimal fracture spacing was proposed.

Li *et al*. (2013) conducted a simulation using multistage fracturing of horizontal wells in order to confirm the correlation between fracture design parameters and production performance in a shale gas reservoir. It was verified that the peak production is changeable according to the stimulated reservoir volume (SRV) and density of secondary fracture.

In the literatures, the impact of secondary fracture on the production performance of reservoir could not be clearly evaluated because the sensitivity analysis was implemented with only a simple design parameter. In this study, a sensitivity analysis was conducted to evaluate the impact of fracture design parameters on gas well performance using CMG's module, GEM. The shale gas reservoir model was built using the properties of the Barnett shale which has well-known reservoir property and a network fracture diagnosed by microseismic fracture mapping data.

For the more accurate analysis of the impact of secondary fracture on the productivity, an additional simulation was performed with a wide range of reservoir properties. It is confirmed that the determination to increase or decrease secondary fracture growth is required to improve productivity in a shale gas reservoir. Based on the results, a guideline is proposed for hydraulic fracturing to improve shale gas production.

2. THEORETICAL BACKGROUND

2.1. Production mechanism of shale gas

Production performance in a shale gas reservoir has a different characteristic with other unconventional reservoirs. A comparison of the possible flow mechanisms among three major types of unconventional gas reservoirs is provided in Table 1. Multiple production mechanisms (molecular flow in fractures) can occur simultaneously during shale gas production (Li *et al*., 2013). Due to the gas flow of shale gas through nanopores shown in Figure 1, fluid flow in the reservoir could be expressed by Eq. 1 and its initial condition and boundary condition were applied by Eq. 2, 3, and 4.

$$\frac{M}{RT}\frac{\partial}{\partial x}\left(\frac{k_{app}}{z\mu}\right)\frac{\partial p_n^2}{\partial x}-\frac{\rho_{ntp}\rho_{pi}V_L}{SV}\frac{4}{r_n(1+bp_n)^2}\frac{\partial p_n}{\partial t}+\frac{4}{r_n}D_k\frac{\partial C}{\partial r}\bigg|_{(r=r_n)} \quad (1)$$

$$I.C.: p_n = p_i; t-0, 0 \le x < L \quad (2)$$

Table 1. Gas production mechanism (Li et al., 2013).

Production Mechanism	Tight Gas	CBM	Shale gas
Desorption from mineral surface to micro-space		o	o
Diffusion from matrix to adjoining fractures		o	o
Darcy's flow in matrix	o		o
Darcy's and Non-Darcy's flow in fractures	o	o	o

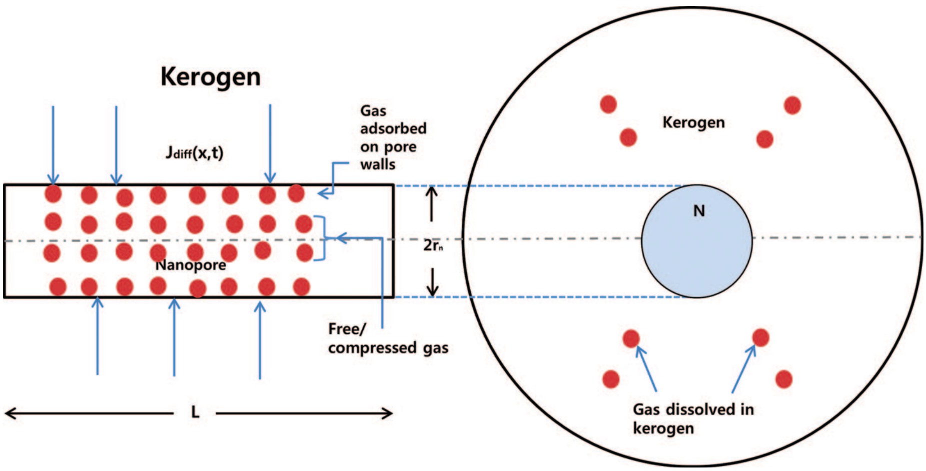

Figure 1. Physical model to model the flow in nanopore (Swami, 2012).

$$B.C.1: p_n = p_k; x = 0, 0 > t \tag{3}$$

$$B.C.1: \frac{\partial p_n}{\partial x} = 0; x = L, t > 0 \tag{4}$$

2.2. Fracture design parameters

When hydraulic fracturing is designed, the fracture design parameters are sufficiently considered because the more fracture network system is complex the more productivity of shale gas is improved in low permeability reservoirs such as shale gas (Cipolla *et al*., 2010). The fracture design parameters were classified into controllable, uncontrollable and indirectly controllable. The uncontrollable parameters are absolute properties of reservoirs (matrix permeability, pressure, depth, etc.). The controllable parameters are designed by an operator who conducts hydraulic fracture and it involves fracturing fluids and operation conditions. The indirectly controllable parameters are decided complexly by uncontrollable and controllable parameter including fracture conductivity, fracture width and fracture half-length and it could be directly related to the productivity of shale gas reservoirs.

3. NUMERICAL MODELING

3.1. Modeling of shale gas reservoir

Due to the complex pore structure in a porous permeable reservoir, estimating the flow direction of fluids is difficult (Swami, 2012). Thus, investigations of the natural and hydraulic fractures and characterization of the fluid flow are required for reservoir modeling and analysis. A complex simulation was also established by the non-Darcy effect, which causes rapid flow velocity, permeability reduction, desorption and diffusion of adsorbed gas, and changes in gas composition (Novelsky *et al*., 2011). To make the model of the hydraulically fractured shale reservoir, the number of grid blocks should be large enough. However, as it takes lots of time, the LS (logarithmically spaced) and LR (locally refined) model had been proposed (Rubin, 2010). The LS-LR model presented similar results with shorter simulation time compared to a fine gridding model.

In this study, a shale gas reservoir model was built using CMG's module, Builder and GEM modules. The model was built with the properties of the Barnett shale and the reservoir properties of economic production. As shown in Table 2, the reservoir depth of Barnett shale is from 6,500 to 9,500 ft, and its net pay varies from 100 to 600 ft. The initial water saturation is similar to connate water, because the Barnett shale play hardly produces water. The adsorbed gas content was higher than other shale plays. Hydraulic fracturing and horizontal well drilling were required to the reservoir, because the Barnett shale has the low natural fracture conductivity and permeability.

The basic model was considered in regard to both the basic properties of Barnett shale and the reservoir parameters for the economic shale gas production as shown in Table 3. To design the horizontal drilling, the diameter of the well was set as 0.25 ft, and the number of grid block was varied from 3,11,5 to 19,11,5. Each grid blocks of the drilled well were all perforated, and the first grid block was connected to the surface.

3.2. Designing values

In order to confirm the impact of fracture design parameters effect on the productivity of shale gas reservoir, the different simulation cases were performed while varying the primary fracture conductivity from 5 to 10 mD-ft as well as the secondary fracture conductivity, the fracture half length, number of stages, and secondary fracture spacing, as shown in Table 4. The operating conditions of the well were also

Table 2. Properties of Barnett shale (Jekins and Boyer, 2008).

Parameter	Value
Depth	6,500–9,500 ft
Net Thickness	100–600 ft
TOC	4.5
Porosity	4–5
Gas Content	150–350 scf/ton
Water Production	0
Well Spacing	80–160 acres
Pressure Gradient	0.44–0.5 psi/ft

Table 3. Model parameters of shale gas reservoir.

Parameter	Value
Permeability	0.0005 mD
kv/kz	0.1
Porosity	0.035
Depth	7,500 ft
Pressure	3,562.5 psi
Natural Fracture Conductivity	0.01 mD-ft
Number of Grid	21(X) × 21(Y) × 9(Z)
X, Y-axis Gird Size	100 ft
Z-axis Gird Size	20 ft
Langmuir Pressure	850 psi
Langmuir Volume	200 scf/ton
Rock Density	120 lbm/scf
Initial Water Saturation	0.2
Area	101.24 acre
Original Gas In Place (OGIP)	11.5 Bcf
Refined Grid	7(X) × 7(Y) × 1(Z)
Length of Horizontal Well	1,700 ft

Table 4. Fracture design parameters for sensitivity analysis.

Parameters	Value
Number of Stages	3, 4, 5
Fracture Half Length	200, 300, 400 ft
Primary Fracture Conductivity	5, 10, 20 mD-ft
Secondary Fracture Conductivity	1.25, 2.5, 5 mD-ft
Secondary Fracture Spacing	25, 33.334, 50 ft

following: a) the bottomhole pressure is 500 psi; b) the maximum gas production rate is 3 MMscf/day; and c) the total production period is 5 years.

4. RESULTS AND DISCUSSION

The 5-year cumulative gas production was presented in Table 5 with the fracture design parameters. According to the number of stages, the cumulative gas production is 1.3, 1.65, and 1.85 billion cubic feet (Bcf). Figure 2(a) shows the pressure distribution after 5-year. The figure shows that the incremental recovery is caused by the increase of the number of stages which is affected by the expansion of SRV and drainage area. In case of the fracture half-length, the cumulative gas production is 1.35, 1.67, and 1.8 Bcf. Figure 2(b) illustrates the significant impact on pressure distribution when the fracture half-length is 400 ft. The incremental recovery caused by the expansion of SRV and drainage area like the impact of the number of stages. According to the primary fracture conductivity, the cumulative gas production is 1.35,

Table 5. Gas production with fracture design parameters.

	Case 1		Case 2		Case 3	
Parameters	Values	Production	Values	Production	Values	Production
Number of stage	3	1.30 Bcf	4	1.65 Bcf	5	1.85 Bcf
Fracture half length	200 ft	1.35 Bcf	300 ft	1.67 Bcf	400 ft	1.80 Bcf
Primary fracture conductivity	5 md-ft	1.35 Bcf	10 md-ft	1.68 Bcf	20 md-ft	1.85 Bcf
Secondary fracture conductivity	1.25 md-ft	2.03 Bcf	2.5 md-ft	2.13 Bcf	5 md-ft	2.25 Bcf
Secondary fracture spacing	25 ft	2.23 Bcf	33.334 ft	2.13 Bcf	50 ft	2.01 Bcf

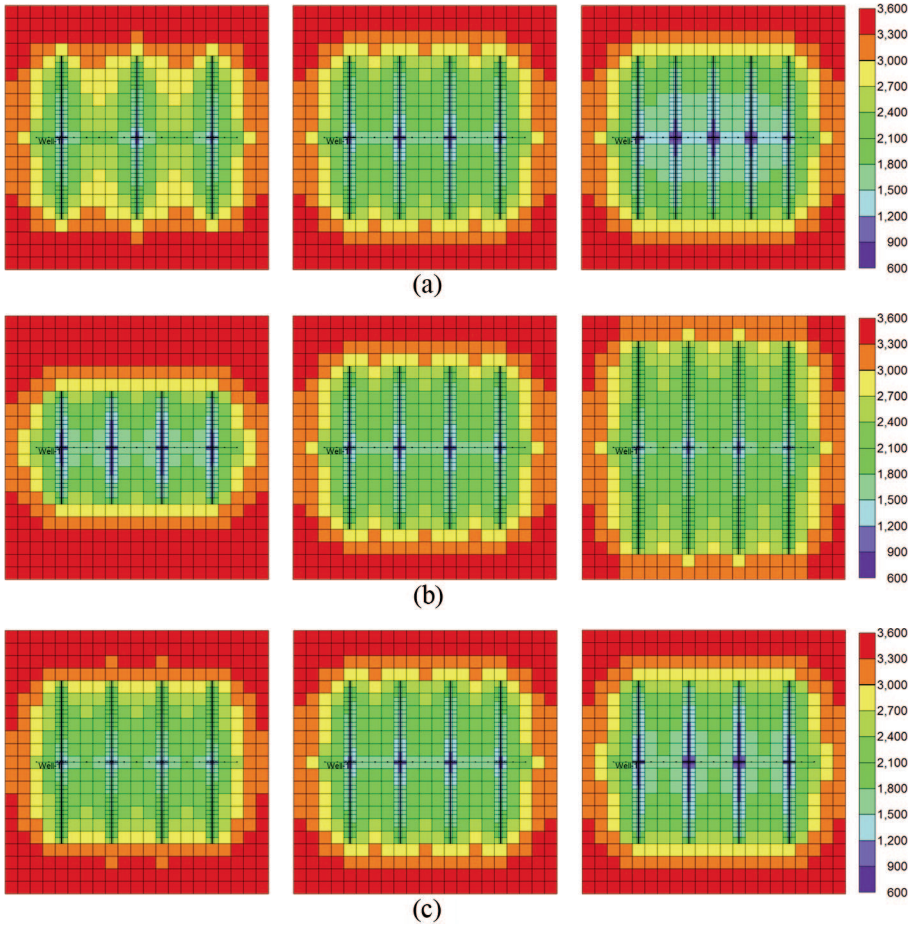

Figure 2. Change of pressure until the end of production: (a) Number of stages (3, 4, 5), (b) Fracture half length (200 ft, 300 ft, 400 ft), (c) Primary fracture conductivity (5 ft-mD, 10 ft-mD, 20 ft-mD).

1.68, 1.85 Bcf. Figure 2(c) shows that the pressure drop was maximized when the primary fracture conductivity was 20 mD-ft. The cumulative gas production is increased in proportion to the increase of primary fracture conductivity, which improved the contact efficiency between the reservoir and SRV. The cumulative gas production is 2.03, 2.13, 2.25 Bcf with the secondary fracture conductivity, which improved the contact efficiency between the reservoir and natural fractures. The cumulative gas production is 2.23, 2.13, and 2.03 Bcf for different spacing of the secondary fracture. In case of the secondary fracture spacing, the gas recovery was improved by the decrease of the value unlike the other deign parameters. The reason is that the narrower the spacing is, the more the contact area increases between the natural fractures and SRV. Thus, the impact of the secondary fracture on the productivity increases when the secondary fracture conductivity is high or the spacing of the secondary fractures is narrow.

For advanced analysis of the impact of secondary fracture, an additional simulation was performed with a wide range of the reservoir conditions including permeability, reservoir depth, natural fracture conductivity, and primary fracture conductivity, as shown in Table 6. Different simulation cases were performed with varying the secondary fracture conductivity from 0.5 to 5 mD-ft and the secondary fracture spacing from 12.5 to 66.667 ft. To analyze the productivity of each case, we made a reference model which is not generated the secondary fracture as shown in Table 7 and set the comparison index. The index means the difference of recovery factor (RF) both the reference model and each case.

4.1. Effect of the natural fracture conductivity

The natural fracture permeability was set in the range of 0.00003 to 0.003 mD to change the natural fracture conductivity. The natural fracture conductivity does not

Table 6. Variable of sensitivity analysis.

Parameter	Variable
Permeability	0.001, 0.0005, 0.0001 mD
Porosity	0.03, 0.035, 0.052
Depth	6500, 7500, 8500 ft
Pressure	3087.5, 3562.5, 4037.5 psi
Natural Fracture Conductivity	0.1, 0.01, 0.001 mD-ft
Primary Fracture Conductivity	5, 10, 20 mD-ft

Table 7. Fracture design parameters of the reference model.

Parameter	Value
Number of Stages	4
Fracture Spacing	400 ft
Fracture Half Length	300 ft
Natural Fracture Conductivity	0.01 mD-ft
Primary Fracture Conductivity	10 mD-ft
Secondary Fracture Conductivity	–
Secondary Fracture Spacing	–

affect OGIP. In the case of secondary fracture conductivity, the cumulative gas production was 1.78–2.95 Bcf. The gas recovery showed improvement of 1.2 to 5.5% in comparison to the reference values. Figure 3 (left) presented a 2.5–4.3% of incremental RF with natural fracture conductivity in the case of secondary fracture conductivity. In the case of the secondary fracture spacing, the cumulative gas production was 1.78–3.24 Bcf. The gas recovery showed improvement of 1.2 to 8.0% in comparison to the reference values. The RF depending on the secondary fracture spacing increases by 4.4–7.8%, as shown in Figure 3 (right). As higher the natural fracture conductivity, the RF is improved by secondary fracture growth.

4.2. Effect of the primary fracture conductivity

The primary fracture conductivity was set as 5, 10, and 20 mD-ft, and the change of the primary fracture conductivity had no effect on OGIP. In the case of the secondary fracture conductivity, the cumulative gas production was 1.50–2.79 Bcf. The gas recovery showed improvement of 1.6 to 4.9% in comparison to the reference values. Figure 4 (left) shows an increase of 2.1–3.3% with primary fracture conductivity in the case of secondary fracture conductivity. In the case of secondary fracture spacing, the cumulative gas production was 1.50–2.94 Bcf. The gas recovery showed improvement of 1.5 to 7.1%. The RF depending on the secondary fracture spacing increases by 3.6–5.6%, which is dependent on the natural fracture conductivity, as shown in Figure 4 (right). As lower the primary fracture conductivity, the greater the improvement of the gas recovery with the secondary fracture growth.

5. DESIGN PROCEDURE FOR EFFECTIVE HYDRAULIC FRACTURING

It was confirmed that the growth and generation of secondary fracture should be considered in order to design the effective hydraulic fracturing. The fracture design parameters should be chosen with regard to the impact of the secondary fracture on productivity. In the Barnett shale reservoir model, the secondary fracture has a high impact on gas production performance when the natural fracture conductivity is more than 0.01 mD-ft or the primary fracture conductivity is less than 5 mD-ft. Based on the sensitivity analysis, a guideline of hydraulic fracturing design considering secondary fracture, which is described as below:

(1) Make a reservoir model and determinate the operating parameters of hydraulic fracturing based on the properties of shale.
(2) Predict the generation of hydraulic fracture based on the operating parameters using fracture simulations such as Mfrac.
(3) Generate a hydraulic fracturing on the reservoir using reservoir simulations such as GEM, and ECLIPSE.
(4) Analyze and confirm the impact of secondary fracture on productivity.
(5) If the productivity is improved by the generation or growth of secondary fracture, the operation parameters should be changed, but it is not, the parameters should be maintained.
(6) If the result of economic evaluation is reasonable, the operation parameters should be changed, but it is not, the parameters should be maintained.
(7) If the operation parameters are changed, the series from (b) to (f) should be repeated until the outfitted optimum condition between fracture operation parameters and reservoir productivity.

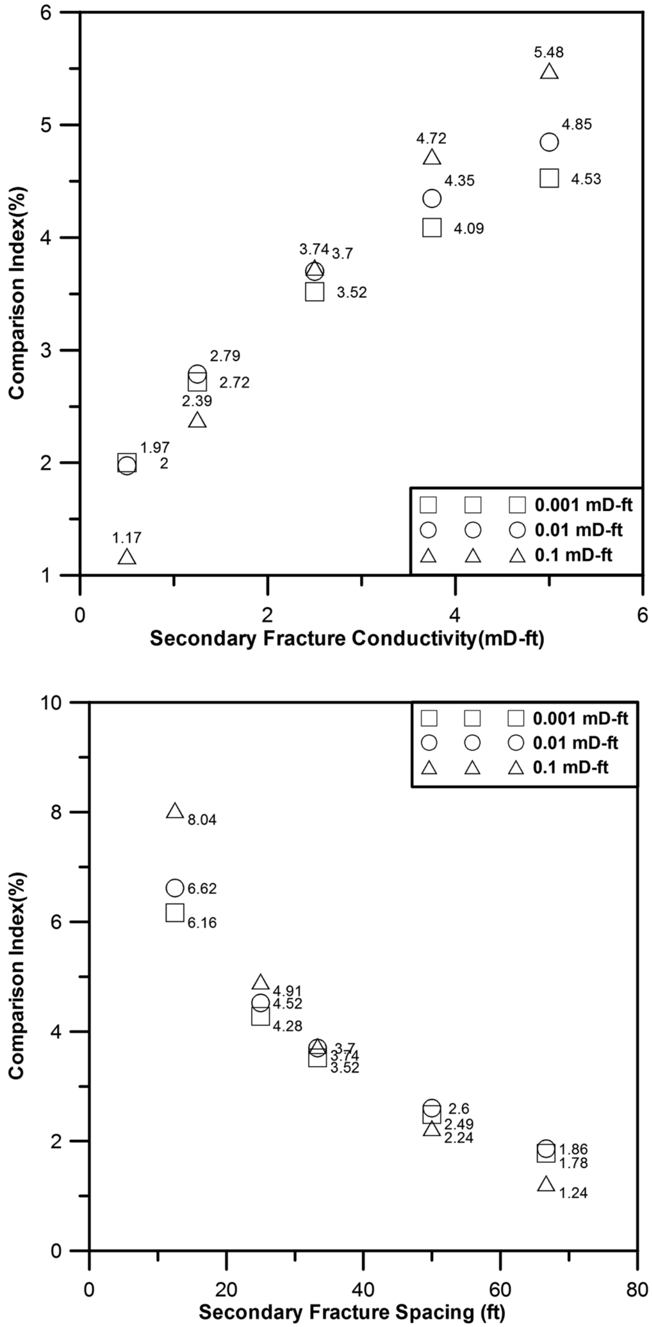

Figure 3. Impact of secondary fracture with natural fracture conductivity.

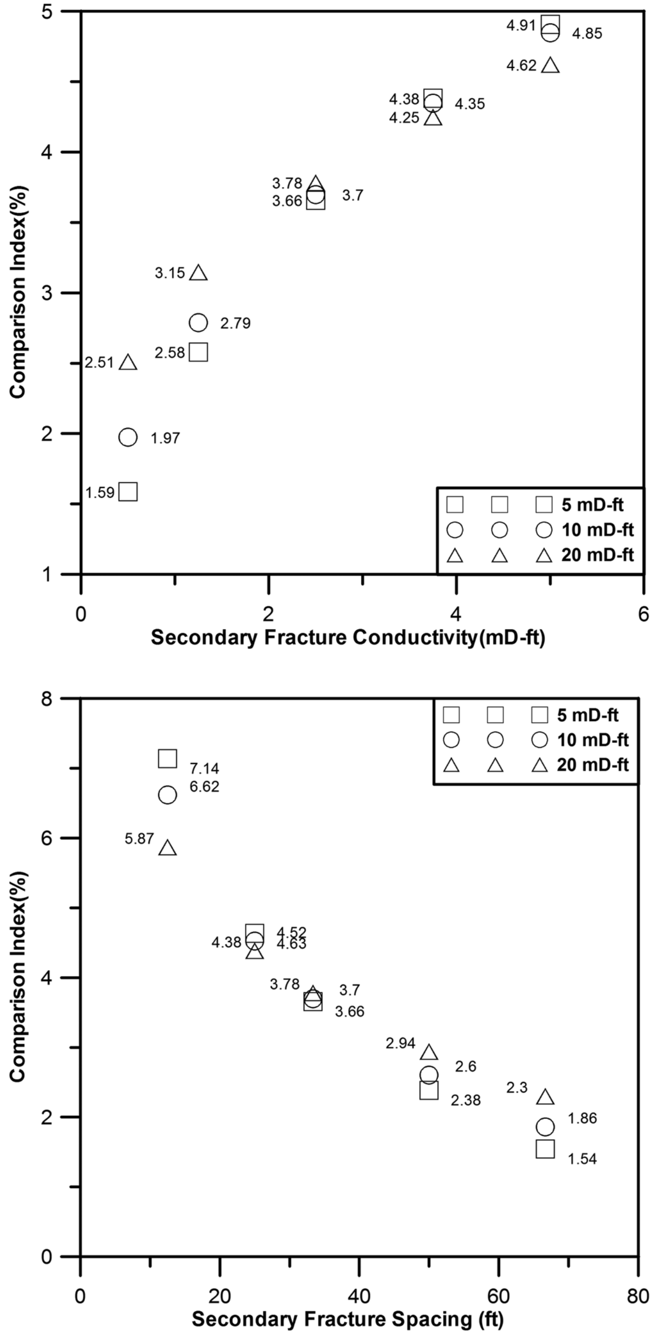

Figure 4. Impact of secondary fracture with primary fracture conductivity.

The guideline can be assisted to find the operating parameters for various shale gas reservoir conditions. Additionally, the growth and generation of secondary fracture is not required when the primary fracture conductivity is more than 5mD-ft, because the series of processes hardly affects the productivity improvement. The guideline was limited to the field of petroleum engineering. Thus, it can be applied after processing the estimation of fracture design parameters. For this reason, hydraulic fracture needs to be preferentially predicted based on the operation parameters of hydraulic fracturing and the characteristics of stress distribution on the shale formation using fracture simulators such as MFRAC, Fracanal, PRACPROPT, etc.

6. CONCLUSIONS

The impact of fracture design parameters on the production performance was analyzed in wide range of shale gas reservoir conditions. From the results, the following conclusions were drawn.

(1) A sensitivity analysis was carried out with fracture design parameters. The productivity was improved, when fracture design parameters were increased except the secondary fracture spacing. In the case of primary and secondary fracture conductivity and secondary fracture spacing, the parameters did not expand SRV, but these are increased the contact efficiency between SRV and the reservoir.

(2) To analyze the impact of secondary fracture on the productivity, additional simulations were performed with a wide range of reservoir conditions. The results confirmed that the productivity is improved when the secondary fracture conductivity increases or secondary fracture spacing decreases.

(3) The growth and present of secondary fracture more improved productivity, when the primary fracture conductivity is low, and the natural fracture conductivity is high. However, the reservoir depth has no impact on productivity.

(4) The determination of whether to increase or decrease secondary fracture is required to improve productivity in a shale gas reservoir. Based on the results, a guideline was proposed to improve the productivity of a shale gas reservoir and it is expected to be a major tool for the determination of fracture design parameters.

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NOMENCLATURE

b	Langmuir's constant (psi^{-1})
C	Gas concentration in kerogen (lbm/ft^3)
D_k	Diffusion constant (md/s)
k_{app}	Apparent permeability of matrix (md)
L	Length of sample (ft)
M	Molecular mass ($lb \cdot mol^{-1}$)
P_i	Initial reservoir pressure (psi);

p_k Pressure of gas dissolved in kerogen bulk (psi);
p_n Pressure of free gas in nanopore, (psi);
R Gas constant, ($10.731 ft^3 \cdot psi \cdot °R^{-1} \cdot lb\text{-}mol^{-1}$);
r_n Pore radius (ft);
T Temperature (°F);
t Time (seconds);
z Gas compressibility factor
μ Gas viscosity (cp);
ρ_{bi} Bulk density of shale at initial reservoir pressure ($lbm \cdot ft^{-3}$);
ρ_{NTP} Gas density at normal temperature and pressure condition ($lbm \cdot ft^{-3}$);

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