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Investigation of the influence of stress shadows on horizontal hydraulic fractures from adjacent lateral wells

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ABSTRACT

Production efficiency from low permeability shale gas reservoirs requires techniques to optimize hydraulic fracture (HF) completions. This may be complicated by the presence of high horizontal in-situ stresses that result in horizontal HF, for example in parts of the Western Canadian Sedimentary Basin in northeastern British Columbia. One strategy involves the simultaneous or near simultaneous hydraulic fracturing of adjacent lateral wells to maximize the fracture network area and stimulated reservoir volume. However, changes to the in-situ stress field caused by an earlier HF on subsequent HF are not accounted for in traditional hydraulic fracturing design calculations. Presented here are the results from a set of transient, coupled hydro-mechanical simulations of a naturally fractured rock mass containing two wellbores using the discontinuum-based distinct-element method. The results demonstrate the influence of stress shadows generated by a HF on the development of subsequent HF from an adjacent well. It is shown here that these interactions have the potential to change the size and effectiveness of the HF stimulation by changing the extent of the induced fracture around the secondary well. Also, the influences of in-situ stress and operational factors on the stress shadow effect are investigated and their effects on different operational techniques are studied.

Introduction

Unconventional shale gas reservoirs require technology-based solutions for optimum development. The successful exploitation of these reservoirs has relied on technological advances in lateral drilling, multiple stage completions, innovative fracturing, and fracture mapping to engineer economic completions. Towards this purpose, hydraulic fracturing (HF) serves as the primary means for improving well productivity. In northeastern British Columbia along the western margin of the Western Canadian Basin, world-class shale gas plays such as the Montney and Horn River are estimated to hold over 1200 trillion cubic feet of natural gas (B.C. Ministry of Energy and Mines, 2012). Recoverable resource numbers are dependent on advances associated with lateral drilling techniques and hydraulic fracturing procedures, especially given the high horizontal stress ratios in this part of the basin, almost all of which involve strike-slip or thrust fault stress regimes (Wikel, 2011).

Simulations demonstrate that shale with ultra-low permeability requires an interconnected fracture network, which comprises both natural and induced fractures, to obtain a reasonable recovery factor (Warpinski et al., 2008). Hence, multiple HF from one or more lateral wellbores provide an effective means to maximize the fracture network surface area. Recent studies have suggested that simultaneous hydraulic fracturing of adjacent wells results in better well performance than fracturing adjacent wells sequentially. This has evolved into the drilling of multiple lateral wells from adjacent pads on leases in the Montney and Horn River in an attempt to maximize the stimulated volume of reservoir rock through HF. However, changes to the in-situ stress field caused by an earlier HF on subsequent HF, referred to here as "stress shadows", are not accounted for in conventional HF design calculations.

Stress shadow effects are potentially critical to the design of multiple lateral well HF treatments, and thus multi-stage single wells or adjacent lateral wells should not be designed identical to a single lateral well treatment. This study describes a series of numerical experiments investigating the influence of stress shadow on HF treatments between adjacent lateral wells. The analysis is carried out for different completion scenarios to investigate their effect on the propagation of horizontal hydraulic fractures. The changes in fluid pressure and corresponding effective stress changes around each wellbore during different completion techniques are examined. The effects of adjacent lateral well hydraulic fracturing on stress shadowing are also studied as a function of the

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reservoir depth, in-situ stress ratio, wellbore spacing, and injection rate.

Influence of stress shadows arising from neighboring hydraulic fractures

Altered-stress fracturing is a concept whereby a HF in one well is affected by another in a nearby adjacent well. One of the earliest studies was done by Warpinski and Branagan (1989), where they presented field tests and finite element calculations examining the modified stress field around a wellbore. Termed "stress shadows", the disturbance of the stress field is especially important when considering a multiple stage HF design. When sequential HF stages are initiated in lateral wells that are close to one another, the stress perturbation caused by one may affect subsequent hydraulic fractures.

Different authors have examined stress perturbation in multi-stage fracturing from lateral wellbores to optimize lateral completion techniques. For example, Fisher et al. (2004) presented results investigating the influence of multi-stage HF with a wellbore separated into equal sections in Barnett shale using microseismic data. They showed that stress diversion is present when the reservoir has been supercharged by a previous fracture treatment stage. They also showed that stress in this region is increased due to locally higher fluid pressures, which influence subsequent stages. Morrill and Miskimins (2012) performed a series of numerical simulations of stresses around a fracture tip in a multiple hydraulically fractured lateral well in order to determine the optimal fracture spacing to avoid stress field interactions and allow for predictable fracture geometries and conductivities in shale gas. Daneshy et al. (2012) reported the results of pressure measurements carried out in four lateral wells where two of the wellbores served as observation wells throughout the project while the other two were actively being fractured. The motivation for these measurements was the detection of HF shadowing created through their extension. They showed that field measurements can be incorporated into the development plan and concluded that real-time monitoring gives the operator time to optimize the treatment and modify future designs accordingly.

A recent consideration regarding stress shadow effects is when closely spaced multiple lateral wells are used. Vermylen and Zoback (2011) studied stress shadow effects in multiple lateral wells in the upper Barnett shale for different completion procedures (simulfrac and zipperfrac) to test the effectiveness of different fracture methods. Simulfracs involve pressurization of two adjacent lateral wellbores at the same time; zipperfracs involve first injecting from one wellbore while the neighboring wellbore is not active and then injecting from the neighboring wellbore after injection into the first wellbore was completed. Vermylen and Zoback (2011) compared the activity level of a fracture stage for the different completion techniques using microseismic events. They found significant differences in stimulation outcome for the different HF procedures owing to stress shadow effects. Nagel and Sanchez-Nagel (2011) performed a numerical evaluation of the effect of multiple HF on stress shadowing as a function of in-situ stress and operational factors. Roussel and Mukul (2011) also performed a series of numerical simulations of stress interference resulting from multiple HF in lateral wells. They analyzed the results for the HF impact on simultaneous and sequential fracturing from lateral wells and concluded that stress interference or reorientation increases with the number of fractures created and depends on the sequence of fracturing in different HF techniques. They also suggested that advantages can be gained through different HF sequences over conventional fracturing to improve the performance of stimulation treatments in lateral wells. Nagel et al. (2013) presented the results of a numerical study to evaluate the effectiveness of multiple lateral wells including modified zipperfracs which involve sequential pressurization of offsetting stages of two adjacent lateral wellbores. They suggested there is a potential for only modest stimulation improvement from the modified zipperfrac. Wu et al. (2012) presented results of their study on stress shadow effects of multi stage HF from a lateral well, showing that fractures can either enhance or suppress each other depending on their initial relative positions. They concluded that accounting for these factors and their effects provides a means to optimize shale completions.

These previous studies have primarily focused on the influence of stress-shadows on subsequent HF, whether off a multi-stage single well or adjacent lateral wells. Further study is required to investigate the role of stress perturbation in multi-stage fracturing from multiple lateral wellbores towards optimization of lateral completion techniques by comparing the stimulated volume for different completion procedures. Also, investigation of the influence of other factors, including the local in-situ stress and operational factors, on HF effectiveness is still required when the reservoir has been supercharged by a previous fracture treatment stage.

Numerical modeling methodology

The Distinct Element Method (DEM) is a Lagrangian numerical technique in which the problem domain is divided through by discontinuities of variable orientation, spacing and persistence (Cundall and Hart, 1993). Fig. 1 provides an idealization of a DEM discretization of a problem domain and representation of the hydromechanical interactions between neighboring blocks. One fundamental advantage of the DEM is that pre-existing joints in the rock mass can be directly incorporated, providing the freedom for the problem domain to undergo large deformations through shear or opening along the discontinuities. This allows the geology to be treated in a more realistic way compared to continuum-based hydraulic fracture codes. The 2-D commercial code UDEC (Universal Distinct Element Code; Itasca Consulting Group, 1999) is used here to simulate the response of a jointed rock mass subjected to static loading and hydraulic injection.

UDEC is capable of modeling the progressive failure associated with crack propagation through the breaking of contacts between the pre-defined joint bounded blocks. The blocks are deformable but remain intact. Key for simulating hydraulic fracturing, UDEC has the capability to model fluid flow through the defined fracture network. A fully coupled hydro-mechanical analysis can be performed in which the mechanical deformation of joint apertures changes conductivity and, conversely, the connectivity changes the joint water pressure, which affects the mechanical computations of joint aperture. The blocks in this assemblage are treated as being impermeable, and fracture flow is calculated using a cubic law relationship for joint aperture:

$$q = ka^3 \frac{\Delta P}{l} \tag{3.1}$$

where, k is a joint conductivity factor (dependent on the fluid dynamic viscosity), a is the contact hydraulic aperture, ΔP is the pressure difference between the two adjacent domains, and l is the length assigned to the contact between the domains. Since the UDEC formulation is restricted to the modeling of fracture flow, leak-off along the fractures diffusing into the intact rock matrix is assumed to be zero (only leak-off into other incipient fractures is considered). Furthermore, the cubic law flow assumption disregards tortuosity. When an incipient fracture contact is broken, the fluid flows into the new fracture.

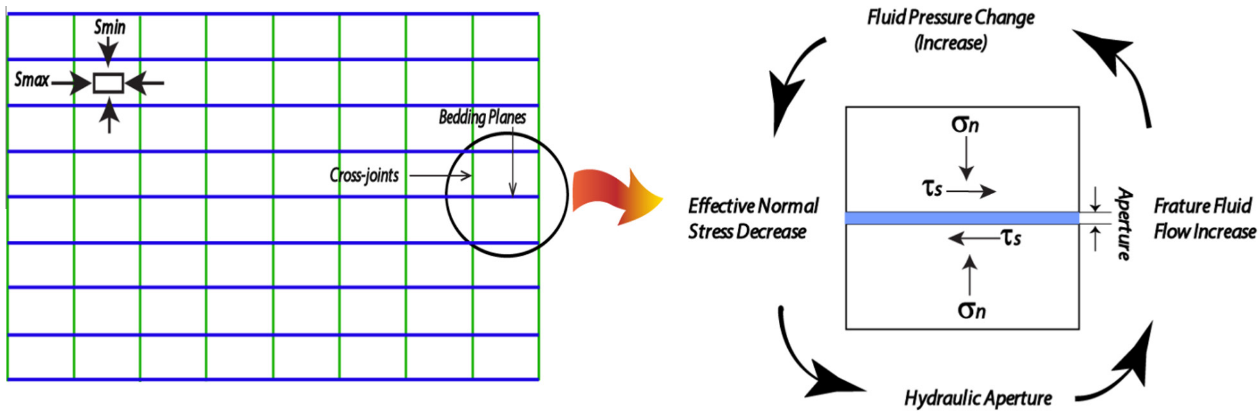

Fig. 1. Discontinuum model: distinct element discretization.

Model set-up and simulation scenarios

The rock mass modeled in this study is represented by two orthogonal planes of weakness, for example bedding and cross-joints (Figs. 1 and 2). These serve as incipient planes along which HF propagation is enabled (as previously noted, the blocks are otherwise non-divisible). Since the purpose of the modeling is to study the interaction of pore pressure fronts and stress fields in the dilated zone around the two approaching hydraulic fractures, and not the interaction between the HF crack tips, the assumption of orthogonal planes of weakness is an acceptable assumption. Initial aperture values of 0.001 mm were assumed for the incipient fractures. Variations in aperture in response to fluid pressure and normal stress changes are assumed to follow a linear relationship described by the normal stiffness (see Table 1). The problem domain is zoned so that smaller blocks are concentrated in the area of interest (between the adjacent injection wellbores) to reduce the influence of bock size on the induced HF length and to balance computing memory requirements against minimizing boundary effects. The time required for executing each model in this study was typically on the order of 7–10 days (using a 3.2 GHz, 64 bit, Intel Core i7 PC with 64 GB of RAM).

The incipient planes of weakness were modeled assuming a Coulomb-slip constitutive model with both peak and post-peak properties; these are given in Table 1. The blocks were modeled as being elastic with a Young's modulus of 30 GPa and Poisson's ratio of 0.25.

The stress condition in this study assumes a horizontal to vertical in-situ stress ratio, *K*, of 1.5 unless otherwise stated, representing a thrust fault stress regime. As previously noted, this approximates the stress environment encountered in parts of the Horn River Basin (Wikel, 2011). The out-of-plane stress is assumed equal to the minimum stress and constant ($\sigma_2 = \sigma_3 = \sigma_V$ = Smin). The model (Fig. 2) represents a 2-D vertical plane where the out-of-plane stress is horizontal. A vertical stress of 20 MPa was assumed (i.e., 1000 m depth). Therefore the stress condition applied to the model is $\sigma_2 = \sigma_3 = \sigma_V$ = Smin = 20 MPa and $\sigma_1 = \sigma_H$ = Smax = 30 MPa. The gravitational variation of vertical stress from top to bottom of the model is neglected because the variation is small in comparison with the magnitude of stress acting on the volume of rock to be modeled.

An initial background pore pressure of 10 MPa was applied. The wellbores pressurized in the model are horizontal and parallel to the out-of-plane direction (Fig. 3). As a result, the alignment of the major principal stress with one of the two orthogonal planes of weakness facilitates the generation of a horizontal HF in the direction of the maximum stress. Boundary conditions are specified for the external boundaries of the model assuming

Table 1
Strength and deformation properties assigned to the modeled planes of weakness.

Incipient fracture property	Value	Units
Friction angle	30	Degrees
Residual friction angle	25	Degrees
Cohesion	1.0	MPa
Residual cohesion	0.0	MPa
Tensile strength	0.5	MPa
Residual tensile strength	0.0	MPa
Normal stiffness	1×10^4	MPa/m
Shear stiffness	1×10^3	MPa/m

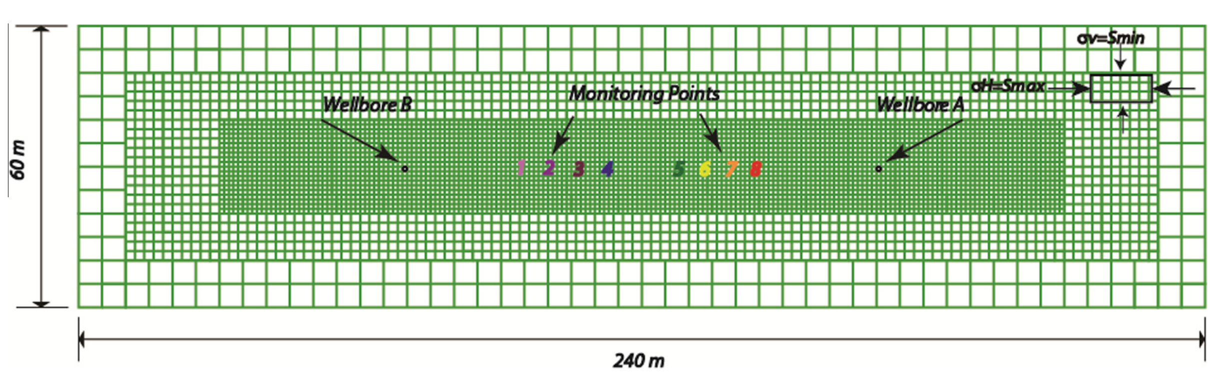

Fig. 2. Rock mass model assuming two orthogonal sets of incipient fracture planes (i.e., planes of weakness), parallel and perpendicular to bedding. Shown are the locations of the two lateral wellbores and 8 monitoring points referred to in subsequent figures.

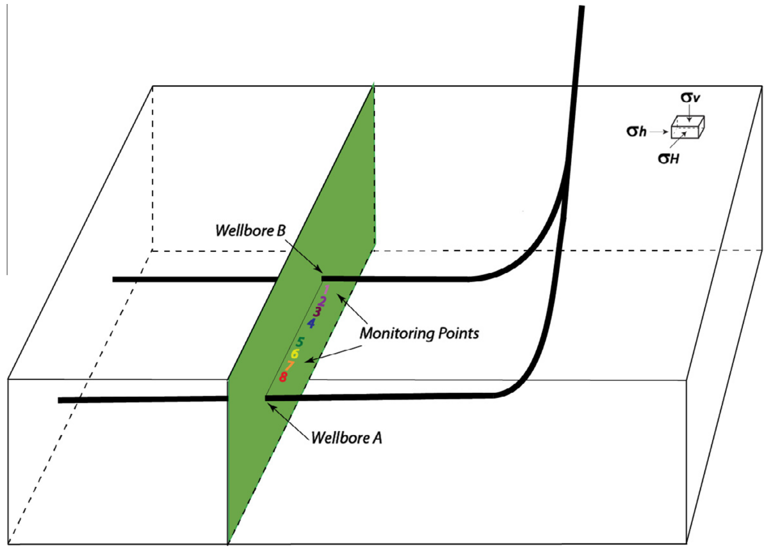

Fig. 3. Three dimensional configuration of the two lateral wellbores.

constant stress and constant fluid pressure conditions. A constant stress boundary condition was selected over fixed displacement conditions based on results from sensitivity testing. These showed that although the hydraulic fractures are interacting in the center of the model, displacement boundaries were too restrictive (creating a stiff system) relative to the maximum model size permissible. Fig. 4 shows the results from the stress boundary sensitivity tests. Fig. 4a shows the aperture profiles and modeled HF lengths as a function of the injection wellbore position relative to the model boundary (with distance changing in 10 m increments). Shifting these to a common injection wellbore position, Fig. 4b shows that the fracture length and aperture profile does not change.

Based on these results, a spacing of 100 m was chosen for the distance between the adjacent injection wellbores. Several monitoring points are positioned between these to track the injection pressures and corresponding stress changes ahead of the HF (Points 1 to 8 in Fig. 2). Point 8 is nearest to wellbore A at a horizontal distance of 25 m. Monitoring Points 7, 6 and 5 follow at 5 m intervals. Points 1, 2, 3 and 4 mirror these positions relative to wellbore B. These locations are strategically selected to investigate the rock mass response in the dilated zone ahead of the HF (see Dusseault and McLennan, 2011).

Three different HF scenarios were tested to investigate the influence of stress shadowing

- Conventional HF, where only a single wellbore is pressurized.
- Zipperfrac HF, where first one wellbore is pressurized (wellbore B in Fig. 2) and then the adjacent well (wellbore A).

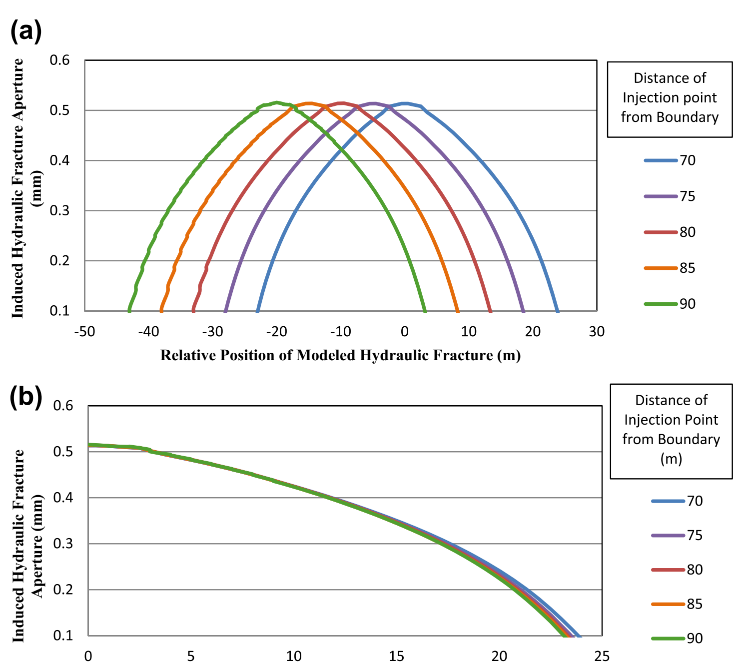

Fig. 4. Sensitivity results for model boundary conditions: (a) HF comparison for decreasing distance between injection wellbore and model boundary (in meters); (b) comparison of HF lengths relative to a common injection position.

- Simulfrac HF, where the two wellbores (A and B) are pressurized simultaneously.

The hydraulic fracture is simulated by applying a fluid injection assuming a constant flow rate of 5 m^3/min. The fluid injection is then discontinued (zero flow rate) to simulate shut-in.

Stress shadow simulation results

The in-situ stress field that exists at depth originates from gravitational, tectonic and remnant diagenesis stress components. These dictate the magnitudes and orientations of the principal stresses, which are often assumed to be aligned with the horizontal and vertical axes relative to the lateral borehole. The in-situ stresses are known to control the direction of fracture propagation, and therefore represent the key boundary condition influencing oil and gas reservoir stimulations. Significant perturbations to the stress field result from any processes that change the reservoir pressure and/or initiates and dilates fractures in the rock. To determine the influence of stress perturbations arising from an initial hydraulic fracture stimulation on subsequent hydraulic fractures from a neighboring injection well, three interaction scenarios as described by Vermylen and Zoback (2011) are modeled here.

Conventional HF (single wellbore injection)

The first scenario involved pressurizing a single lateral wellbore (A in Fig. 2) to generate a hydraulic fracture. Fig. 5 shows the changes in fluid pressure at the different monitoring points between the injection and neighboring wellbore as previously described (Points 1 to 8 in Fig. 2). Fig. 5 shows that during injection, the pressure values recorded at the monitoring points increase and are highest nearest to the injection wellbore. As previously noted, the monitoring points are positioned in the dilated zone ahead of the HF; i.e., the HF has not yet reached the first monitoring point (Point 8) and the pressures shown are those of the pore pressure perturbation ahead of the HF. After injection is discontinued, a gradual pressure decline is seen in the pressure history plots for all points. The declining pressure occurs due to dissipation of fluid pressure back to the wellbore and leak-off to neighboring incipient fractures.

The corresponding perturbation of the in-situ stress field adjacent to the pressurized wellbore is seen in the horizontal stress histories (Fig. 6). Here the horizontal stress in the dilated zone is seen to locally increase through a mechanism in which the vertical opening (dilation) of the incipient fractures results in the bounding blocks (matrix) being compressed vertically. In response, the blocks expand horizontally (Poisson ratio effect), generating higher stresses horizontally since the blocks are confined. The stress perturbation decays as the pore pressures slowly dissipate after shut-in. Subsequent diffusion into the incipient fractures, and thus further dissipation of pressures, is very slow after this point. Part of the induced stresses falloff as the opened fractures in the dilated zone close, while a fraction remains due to the permanent dilation of fractures preserved in the model (where the incipient fractures have undergone shear). The presence of the disturbed stress field means that if a second wellbore is pressurized, the stress field influencing the propagation of the second hydraulic fracturing has been altered from that of the initial in-situ stress condition.

The stress shadow effect is manifest in the elevated principal stresses that develop around the pressurized wellbore and radiates outward into the reservoir for a significant distance (Fig. 7). Note

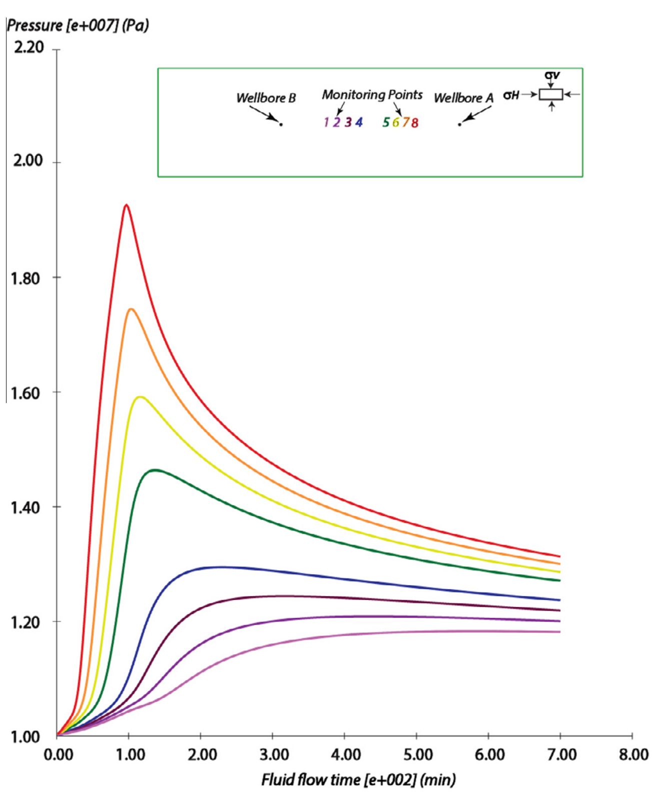

Fig. 5. Conventional hydraulic fracturing scenario (single well): fluid pressure histories for different monitoring points between the two wellbores, with injection occurring from Wellbore A, for a period of 90 min.

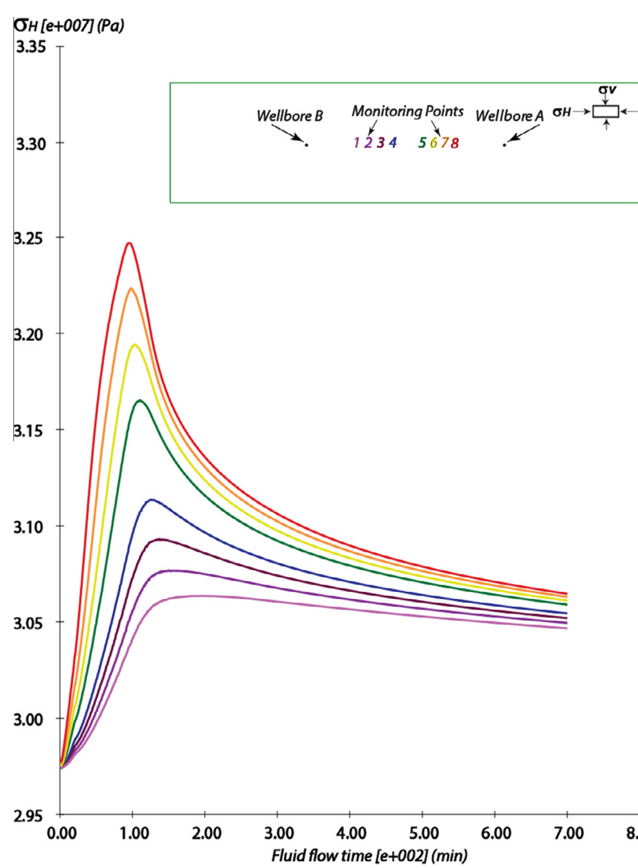

Fig. 6. Conventional hydraulic fracturing scenario (single well): stress histories for different monitoring points between the two wellbores, with injection occurring from Wellbore A, for a period of 90 min.

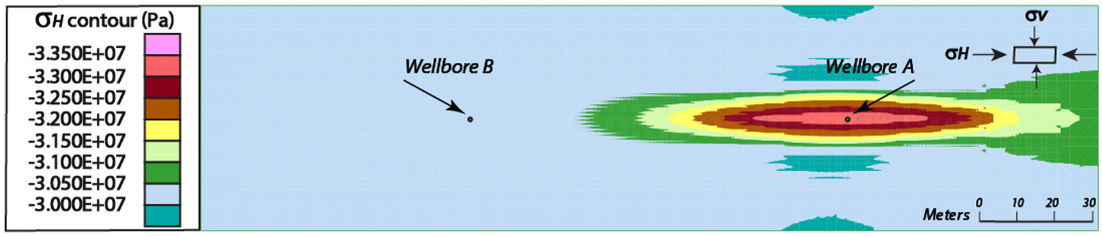

Fig. 7. Stress distribution, resulting from the pressurization of wellbore A, for a period of 90 min.

that this figure. shows some minor boundary effects on the right side of wellbore A, but the focus here is on the rock mass response and stress field disturbance to the left side of wellbore A, which are not significantly affected (as shown through the boundary effect sensitivity analysis reported in Fig. 4).

Zipperfrac HF (alternating injection between adjacent wellbores)

The second treatment scenario involves first injecting (i.e., fracturing) from wellbore B, and then shutting-in at wellbore B and injecting into wellbore A. The results are presented in Figs. 8 and 9. Fig. 8 shows the pressure increase at different points within the rock mass between the two wellbores. Points 1 to 4, located closer to the pressurized wellbore B, detect the pressure rise first with Points 5 to 8 only detecting a muted response away from the injection. After shut-in at wellbore B and initiation of injection at wellbore A, the monitoring points closer to A then respond and those closer to B start showing pressure decay. The pressure decay around the first wellbore continues until the pressure front from the second wellbore arrives resulting in a lower rate of depressurization. The corresponding horizontal stress changes at the monitoring points are shown in Fig. 9.

The perturbation of the in-situ stress field after the first and second stimulations can be seen in the maximum horizontal stress contours in Fig. 10a and b, respectively. The stress perturbation

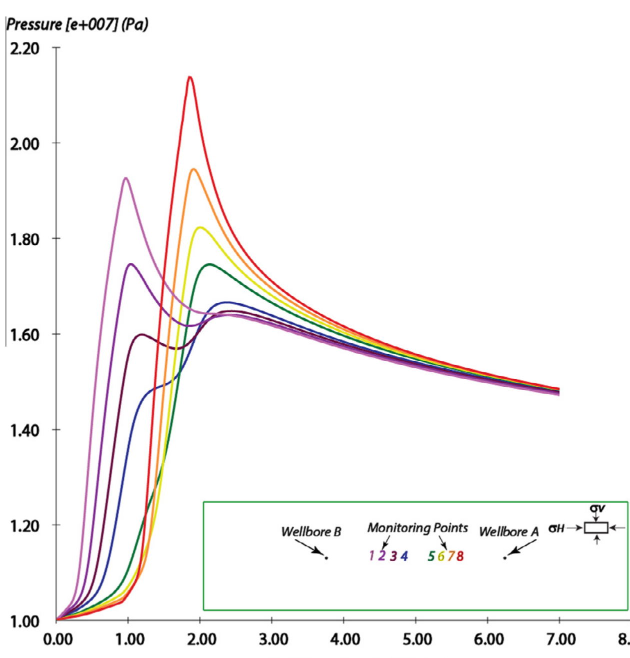

Fig. 8. Zipperfrac scenario between two alternating injection boreholes: fluid pressure histories for different points between the two wellbores. At 90 min, the injection at wellbore B is shut-in and injection started at wellbore A.

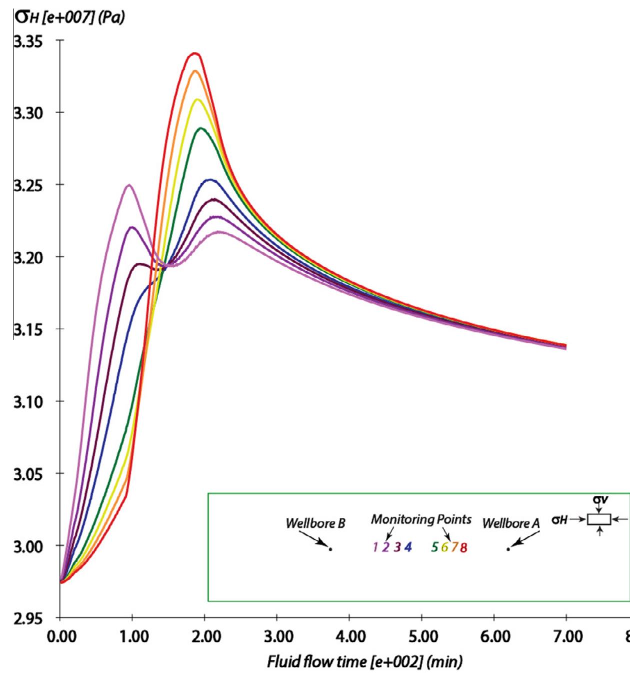

Fig. 9. Zipperfrac scenario between two alternating injection boreholes: stress histories for different points between the two wellbores. Point 1 is closest to the initial injection (wellbore B), with Point 8 being closest to the subsequent injection (wellbore A).

decays after the injection pressure ceases, but as before, do not return to the initial in-situ stress due to the permanent dilation of incipient fracture that have undergone shear. This means that if either wellbore is pressurized soon after, the hydraulic stimulation generated will be controlled by a disturbed stress field and not the original in-situ stress field.

Simulfrac HF (simultaneous injection between adjacent wellbores)

The simulation of hydraulic fracturing for the third scenario is conducted where both lateral wellbores (A and B) are pressurized at the same time. The results are presented in Figs. 11 and 12. Fig. 11 shows the changes of fluid pressure at different points between the two wellbores. Here, simultaneous pressurization results in all six monitoring points showing a fast response to the hydraulic fracturing injection. After the injection is discontinued in both wellbores, a gradual pressure decline is seen in the pressure history plot for all points.

The corresponding stress responses around the two wellbores (Fig. 12) are similar to those around wellbore A for the single well injection scenario (i.e., Fig. 6), but with higher stress values. This indicates that the individual pressure fronts induced at the two neighboring wellbores communicate with each other and affect the stresses that develop at each adjacent wellbore.

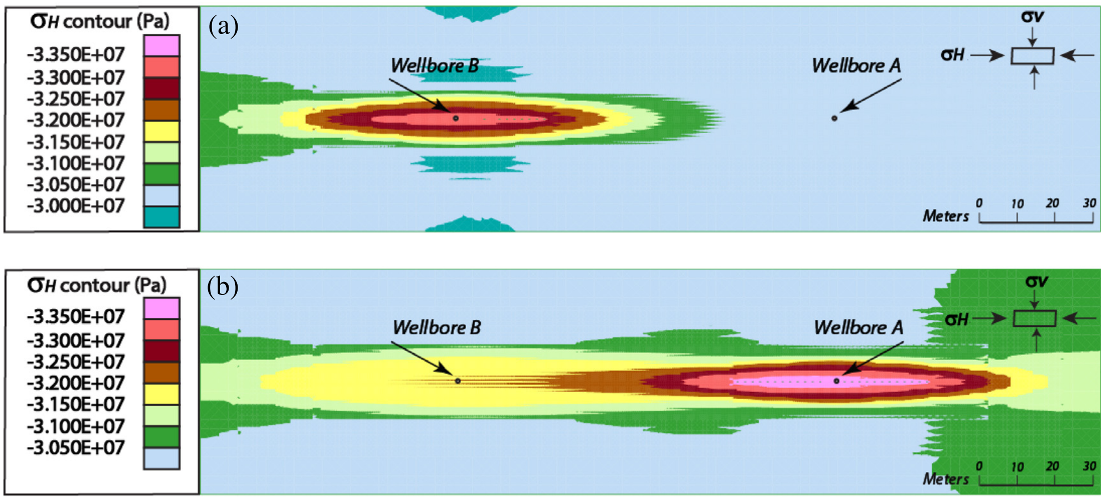

Fig. 10. Stress distributions arising from the zipperfrac scenario, after injection into: (a) wellbore B for a period of 90 min, and (b) then into wellbore A, for a period of 90 min.

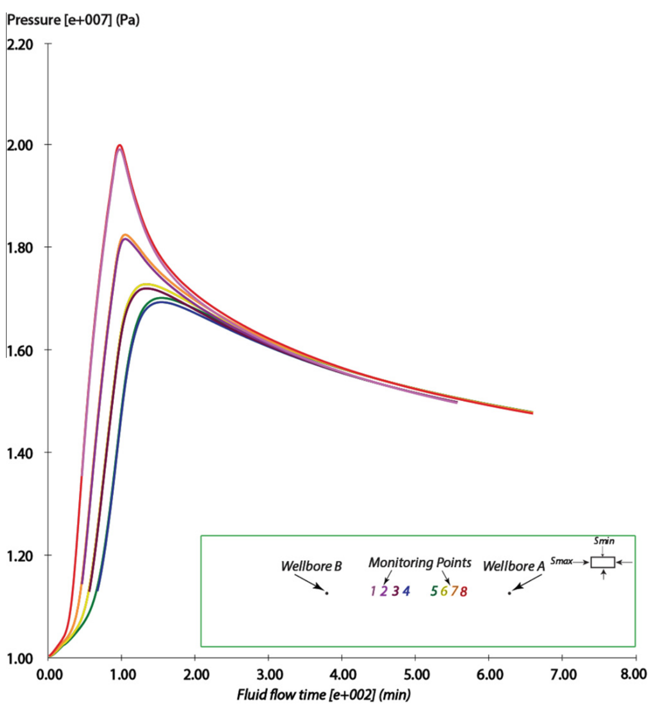

Fig. 11. Simulfrac scenario between two simultaneously injecting hydraulic fracturing wellbores: fluid pressure histories for different points between the two wellbores. Point 1 is closest to injection well B and Point 8 closest to injection well A.

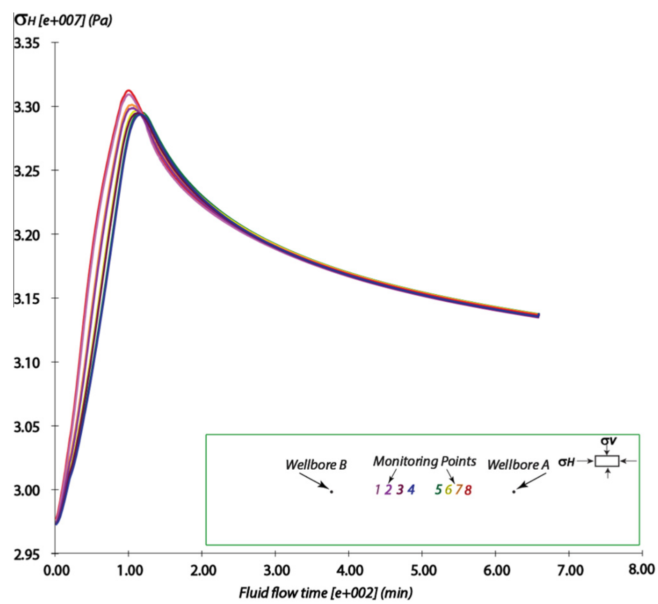

Fig. 12. Simulfrac scenario between two simultaneously injecting hydraulic fracturing wellbores: stress histories for different points between the two wellbores. Point 1 is closest to injection well B and Point 8 closest to injection well A.

Further inspection of the modeled stresses through the horizontal stress contours shows the development of a stress shadow. Initially separate elevated stress zones develop, locally centered on each wellbore (Fig. 13a). The elevated stress zones grow during the pressurization as show in Figs. 13b and c and eventually, the two stress perturbations merge into a larger disturbed stress field (Fig. 13d). Thus, the stress distribution around one wellbore in this case is altered by the other and vice versa.

Scenario comparison

Fig. 14 shows the change in induced hydraulic fracture aperture as a function of distance away from the injection well for the three different scenarios, where the injection well is positioned at zero. Figs. 15 and 16 compare the maximum hydraulic fracture apertures and lengths for each, respectively. These indicate that the hydraulic fracture aperture and length increase from conventional to simulfrac to zipperfrac.

The reason for these increases is the elevated fluid pressures resulting from a previous treatment which changes the effective stresses acting normal to the propagating hydraulic fracture. The method of interpretation here is based on superposition of the pressure effect of the neighboring well at the well in question (Matthews, 1961). As previously noted, the incipient fractures in the model are permeable but very tight, therefore pressure diffusion is small. Based on the time intervals simulated, there is a superposition of the pore pressure fields as the second injection is started before the pressure influence of the first can diffuse into the low permeability fracture network. This results in higher formation fluid pressures and subsequent stress shadow interactions

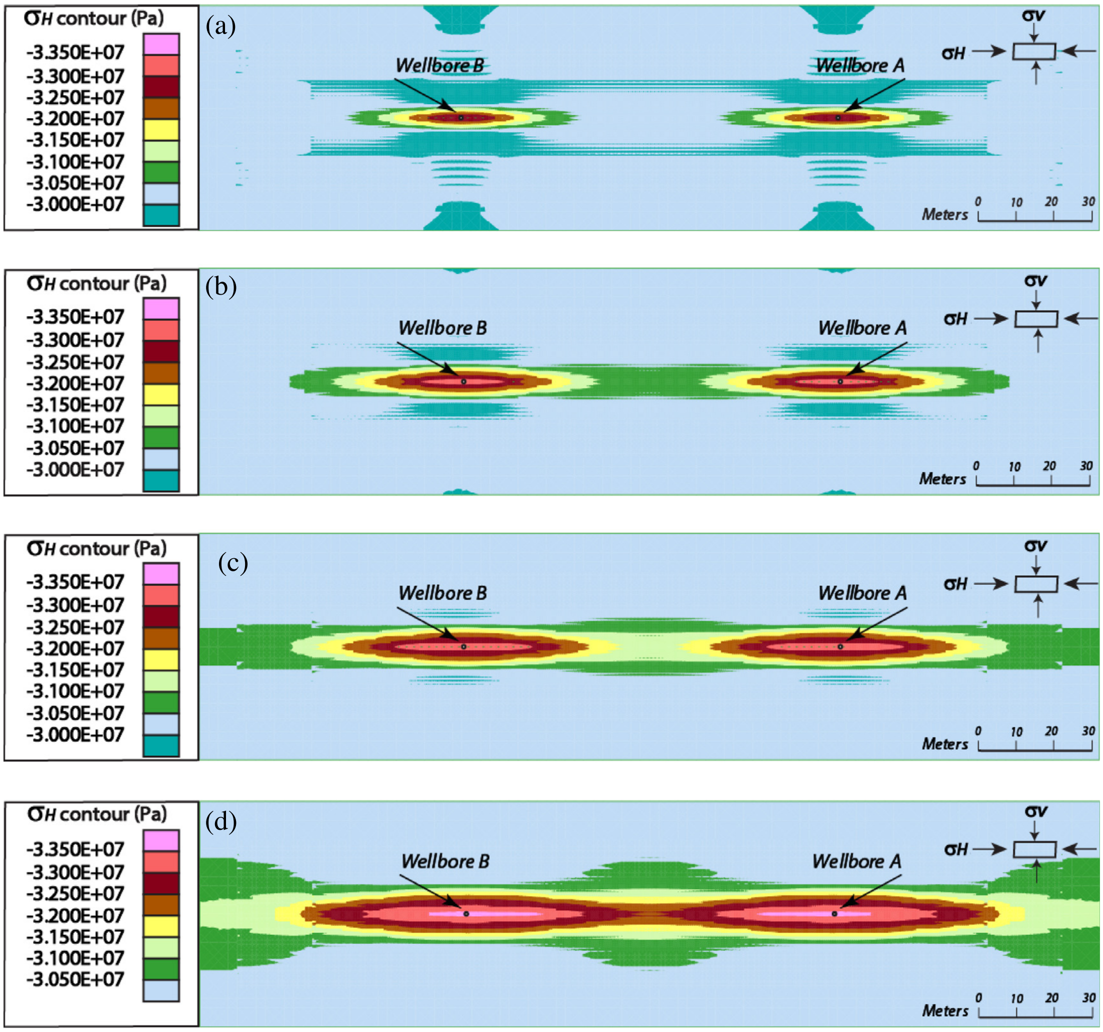

Fig. 13. Stress distributions around simultaneously pressurized wellbores during pressurization (simulfrac scenario): (a) after 20 min of injection, (b) after 40 min of injection, (c) after 60 min of injection, (d) after 90 min of injection.

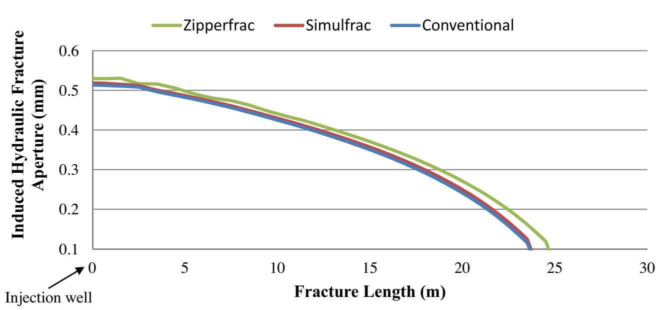

Fig. 14. Hydraulic fracture comparison between the three modeled scenarios.

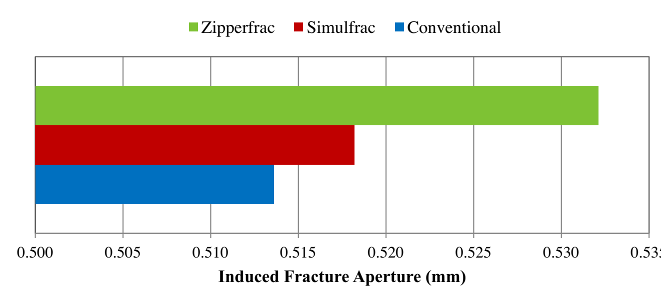

Fig. 15. Maximum induced hydraulic fracture aperture comparison between the three modeled scenarios.

between wellbores, which in turn result in larger fracture apertures, more concentrated fluid flow (via the hydro-mechanical coupling between aperture and flow), and decreasing effective stresses, which together produce longer hydraulic fracture lengths assuming equal injection times.

These results are partly dependent on the model size, which is limited here by computing times required as well as the pumping rate and duration chosen for the analysis. For a typical hydraulic fracturing stage, fluids may be pumped at a rate of 50–60 BPM (barrels per minute) for a duration of approximately 150 min (Vermylen and Zoback, 2011). For the analysis carried out here, numerical limitations restricted the fluid pump rate to 30 BPM (5 m^3/min) for a duration of 90 min. Regardless, the results still show the relative hydraulic fracture length increase from conventional to simulfrac to zipperfrac scenarios.

Influence of in-situ stress and operational factors

The influence of in-situ stress and operational factors on the stress shadow effects should be considered when designing a HF treatment for maximum extent and recovery factor. In the following sections, the sensitivity of the stress shadow effect is

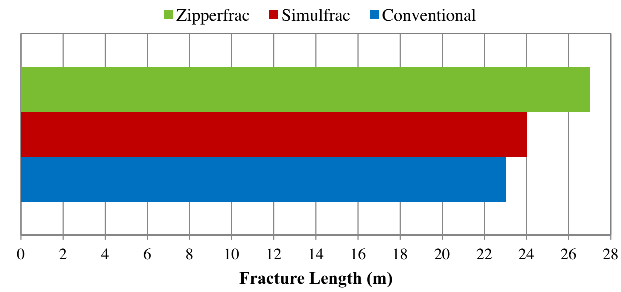

Fig. 16. Hydraulic fracture length comparison between the three scenarios.

further examined as a function of reservoir depth (i.e., target formation depth), in-situ stress ratio, well spacing, and injection rate.

Influence of reservoir depth

The influence of reservoir depth was examined whereby the vertical stress was increased while maintaining a constant in-situ stress ratio ($K = 1.4$). Thus the sensitivity of the hydraulic fracture propagation to confining stress represented by the overburden depth was tested.

Fig. 17 shows the hydraulic fracture length for the three different scenarios as a function of depth; each is normalized to the conventional HF length for each depth. Comparison of the HF lengths as a function of both scenario and depth is not compatible as different fluid injection times were applied for the different modeled depths. This was necessary to enable the stress shadow effects from the neighboring wellbore to develop roughly equally for each depth, given that the higher in-situ stress conditions with depth adversely influenced the penetration rate of the injection. Thus, increased injection times were imposed for increasing reservoir depths to generate the same HF length under the conventional scenario for all depths.

The results confirm that the zipperfrac technique continuously produces the longest HF at each depth. More specific to the influence of reservoir depth, the results show that the relative difference between the conventional, simulfrac and zipperfrac fracture lengths increases as HF depth increases. This is because the perturbation to the in-situ stress field caused by the first HF in the zipperfrac sequence decays more slowly with increasing depth as the higher stress magnitudes dampen the rate of leak-off. As a result, the second wellbore is pressurized while there is still a significant stress shadow remaining from the first wellbore HF, resulting in higher fluid pressures driving the HF propagation.

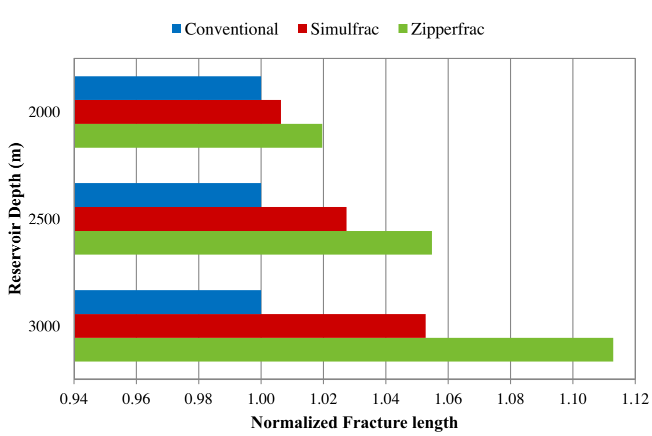

Fig. 17. Normalized hydraulic fracture length comparison between the three scenarios for different reservoir depths.

Influence of in-situ stress ratio

Starting from the initial stress state assumption that the horizontal to vertical in-situ stress ratio, K, is greater than one (thrust faulting regime), the sensitivity of the modeled HF to K was tested for the three different stimulation scenarios (conventional, zipper and simul-frac). In these models, the vertical stress was held constant and the horizontal stress increased (often, the magnitude of the horizontal stress involves significant uncertainty and therefore added geo-risk to the success of the HF operation). The out of plane stress is assumed equal to the minimum stress and constant.

Fig. 18 shows the hydraulic fracture length for each scenario as a function of stress ratio, K, normalized to the longest fracture length for all model simulations. Fig. 18 shows HF length increases with increasing horizontal stress (as vertical stress is kept constant).

Here, the higher horizontal stress facilitates fracture opening in the vertical direction, and as a result, the tensile rupture of the rock in the horizontal direction occurs with less resistance to dilation. An analogy can be drawn with Jaeger and Cook's (1979) analytical solution for stress distribution around an elliptical opening of width W and height H subject to a vertical (p) and horizontal (Kp) stress, as shown in Fig. 19.

The tangential stress at the tip of the elliptical opening (Point A in Fig. 19) can be calculated by

$$\sigma_A = p\left(1 - K + \sqrt{\frac{2W}{\sigma_A}}\right) \tag{3.2}$$

where, the radius of curvature at the tip of the elliptical opening,ρ_A is equal to $\frac{H^2}{W}$.

In the above equation, $\left(\sqrt{\frac{2W}{\rho_A}}\right)$ is a geometric term and depends on the geometry of the ellipse. With internal water pressure acting against p, the above equation demonstrates that the stress resisting

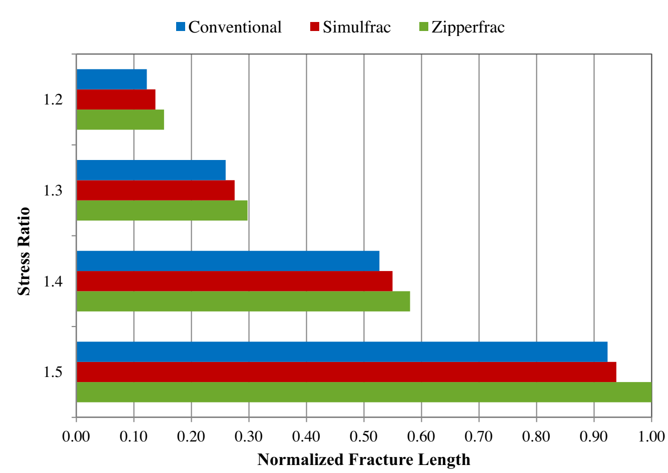

Fig. 18. Normalized hydraulic fracture length comparisons between different completion scenarios for different horizontal to vertical in-situ stress ratios.

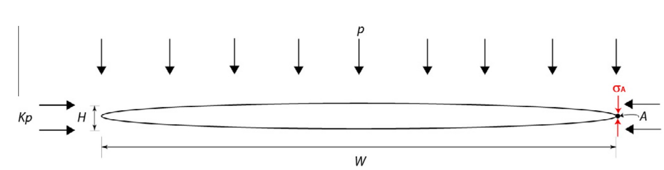

Fig. 19. Geometry of an elliptical opening in a biaxial stress field.

fracture opening at Point *A* decreases when *K* increases. Thus, the induced fracture length for a horizontal HF increases as the *K* ratio increases.

Influence of wellbore spacing

The importance of wellbore spacing in the ultimate economic recovery from a reservoir has been studied by Holditch et al. (1978). They performed numerical modeling to study the optimum well spacing for different reservoirs and concluded that determination of the optimum well spacing is not a "common sense" type problem and different in-situ and operational factors must be considered before the optimum development plan can be formulated.

Simulation results in this study using different wellbore spacing suggest that, as would be expected, the distance between adjacent lateral wells (i.e., stress shadow communication) affects the extension of the HF. Fig. 20 shows the change in fracture aperture as a function of fracture length from the injection wellbore for different wellbore spacing. These results are for the simulfrac scenario, which were chosen for this demonstration to omit the asymmetric influence of time on stress perturbation decay; i.e., with the two wellbores being pressurized at the same time, the respective leak-off of the fluid pressure front from each is symmetric. Fig. 20 shows the closer the neighboring wells, the stronger the stress shadow effect in terms of promoting longer induced HF. This arises because the pressure fronts reach each neighboring well faster and have less time to decay. A similar response is observed for the zipperfrac scenario, with increased HF lengths developing for closer wellbores because the pressure around the first wellbore has less time to decay before injection is started from the second wellbore. The shorter the distance between the two wellbores, the more pressure from the earlier treatment is available to enhance any subsequent treatments.

Fig. 21 shows the hydraulic fracture lengths for the different wellbore spacings, normalized to the longest HF modeled (i.e., zipperfrac with 60 m wellbore spacing). The results show that although the closeness of neighboring wellbores has a strong positive influence on both the zipper- and simul-fracs, the simulfrac scenario is more sensitive to wellbore spacing. This is because the interaction between the neighboring wellbore pressure fronts develops faster (relative to the zipperfrac) when injection is performed at the same time. This is not as pronounced for the zipperfrac scenario because of the timing difference between wellbore pressurization schedules. For the zipperfrac, the fluid pressure from the first wellbore treatment diffuses towards the second wellbore but also leaks-off reducing the elevated pressure around that wellbore compared to the simulfrac case.

Influence of injection rate

The influence of fluid injection rate on hydraulic fracturing from a single well has been investigated by de Pater and Beugelsdijk (2005), with focus on the characteristic time scales of the HF

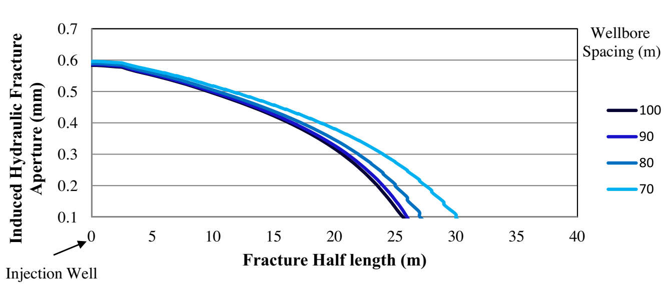

Fig. 20. Hydraulic fracture comparison for different wellbore spacing.

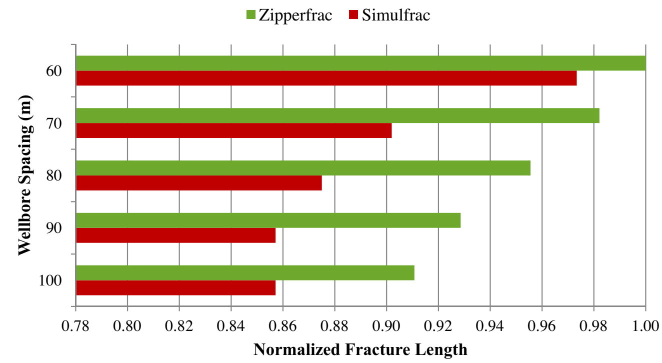

Fig. 21. Normalized hydraulic fracture length for simulfrac and zipperfrac scenarios with different wellbore spacing.

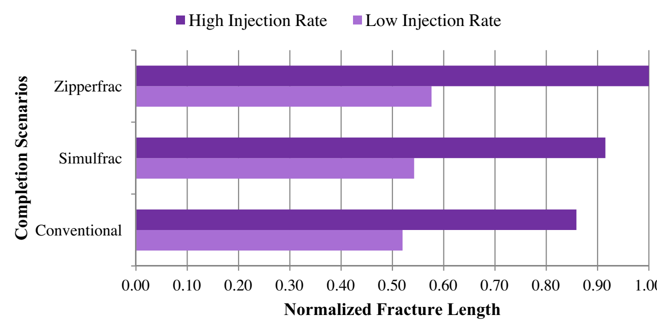

Fig. 22. Normalized hydraulic fracture length for simulfrac and zipperfrac scenarios with different injection rate.

process. They found from numerical modeling results that different fluid injection rates change the stress concentration around the wellbore, which in turn affect the HF propagation.

The fluid injection rate was also varied here between 5 m^3/min and 10 m^3/min, to model its influence for the three different scenarios. The results show that by increasing the injection rate, the stimulated fracture lengths increase for all three scenarios (Fig. 22), and is most pronounced for the zipperfrac. This supports the findings presented earlier with respect to the sensitivity of the zipperfrac scenario to the pressure front.

Discussion and conclusions

It is generally accepted that multiple hydraulic fractures generated from neighboring lateral wells provides the best completion option for stimulating unconventional and low permeability oil and gas reservoirs (e.g., Yost and Overbey, 1989). This system approach has provided significant production results and is largely responsible for the successful development of several oil and gas fields in the United States and Canada, and is rapidly seeing acceptance worldwide. While the industry has made significant advancement in developing mechanical systems for carrying out these completions, progress in the design of multiple hydraulic fracturing with respect to wellbore spacing, reservoir characterization, in-situ stress state, injection rate and overall production optimization requires a more thorough mechanistic understanding of their influence. Understanding the effect of stress shadowing has significant benefits with respect to impact and risk mitigation on the cost and profitability of these operations. This study has been carried out to contribute to the existing body of knowledge, specifically with respect to the modeling of stress shadow effects resulting from conventional, zipper- and simul-fracs from neighboring wellbores. The results were obtained using distinct element numerical modeling techniques based on the hydro-mechanical coupled response of a fracture flow system. The results elaborate on the concept of stress perturbation through hydraulic fracturing, including the development of a dilation zone ahead of the hydraulic fracture and the effect of multiple hydraulic fractures on stress shadowing as a function of in-situ stress and other operational factors, as a means to optimize shale completions by understanding the influence of these factors on hydraulic fracture propagation. The results simulating different fracturing techniques/schedules suggest that the zipperfrac is the most effective technique where multiple lateral wells are stimulated, producing the longest fractures for the same injection rate and volume compared to conventional and simulfrac techniques.

In addition to adopting the most effective technique for fracturing multiple lateral wells, improved understanding of the in-situ and operational conditions will allow designers and operators to help control the hydraulic fracture in the area being treated. In this study, the effects of in-situ stress as well as some operational factors are investigated to identify those factors that have the most influence on the effectiveness of the treatment. It was found that the influence of reservoir depth has the biggest influence on how much the zipperfrac outperforms the other two techniques. The horizontal to vertical stress ratio was also seen to have a considerable influence. Regarding the operational factors, wellbore spacing has a significant effect on the extension of hydraulic fractures promoting longer induced fractures with closer wellbore spacings. The model responses were less sensitive to injection rate, but its influence was still significant.

The simulations show great potential in providing a deeper understanding of the influence of stress shadow effects on the propagation of hydraulically induced fractures. Further work will include the use of microseismic data for further investigation of fracture behaviors and simulation of a specific multiple lateral wellbore hydraulic fracturing performance in a gas shale reservoir. Also with continuous advances in computation speed and software pre-and post-processing capabilities, further work should explore the application of three dimensional discontinuum codes in modeling of multiple lateral wellbores.

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