Geomechanics for Energy and the Environment 36 (2023) 100507

Contents lists available at ScienceDirect

Geomechanics for Energy and the Environment

journal homepage: www.elsevier.com/locate/gete

Modifying the orientation of hydraulically fractured wells in tight reservoirs: The effect of in-situ stresses and natural fracture toughness

Joseph Sherratt, Amin Sharifi Haddad *, Roozbeh Rafati

School of Engineering, University of Aberdeen, Aberdeen, United Kingdom

A R T I C L E I N F O

Editors-in-Chief: Professor Lyesse Laloui and Professor Tomasz Hueckel

Keywords:
Hydraulic fracturing
Natural fracture
In-situ stresses
Well orientation

A B S T R A C T

Hydraulic fracturing in shale formations containing natural fractures can lead to complex and branched fracture networks which may fail to efficiently access hydrocarbons deep in the formation away from the well. In this study, to minimise the negative effects of natural fractures, the orientation of hydraulically fractured wells in such formations is investigated with the focus on the effects of in-situ differential stresses and toughness of natural fractures. To explore the impact of geomechanical properties on gas production from hydraulically fractured wells, fractures were first up scaled and then gas production from the reservoir was investigated. The results show that low natural fracture toughness and differential in-situ stress both increase the tendency of propagating hydraulic fractures to exploit natural fractures. Under these conditions, it was found that drilling the well in a modified orientation could result in a higher recovery factor compared to the wells drilled parallel to the direction of minimum horizontal stress. This is due to the larger stimulated reservoir volume through a synergy between the hydraulic and natural fractures. However, high differential in-situ stress and fracture toughness both lead to a transition from this tendency, in which hydraulic fractures cross natural fractures rather than exploiting them. As a result, changing the well orientation in these scenarios are less efficient than the industry standard. The results of this study demonstrate a window of geomechanical scenarios in which changing well orientation is beneficial, can be produced as a fast-screening method for engineers to determine the optimised well orientation.

1. Introduction

Hydraulic fracturing technique provides an opportunity to produce hydrocarbons from low permeability formations. However, hydraulic fracturing process is expensive, and it requires emerging technologies and advanced analyses to increase the efficiency of the well stimulation to keep the development of such resources economically viable. Hydraulic fractures extend in a direction where the least energy is required to open the rock when the formation is homogeneous. The stress in the vertical direction in most shale formations has the higher magnitude. As a result, hydraulic fractures tend to orientate themselves in vertical plane and parallel to the maximum horizontal stress, $\sigma_{h,\max}$. Therefore, to maximise gas recovery drilling should be in the direction of the minimum horizontal stress, $\sigma_{h,\min}$.[23] This can lead to a larger reservoir stimulated volume around the well. Therefore, to develop large shale gas prospects drilling a large number of wells with very similar designs is plausible, and efficient recovery is dependent on achieving uniform fracture propagation along and between the wells. Zhang et al.[30] conducted a laboratory investigation on hydraulic fracturing process using rock samples from different fields. The outcomes of their study highlighted that the differential horizontal stress and formation leak-off coefficient significantly affect the hydraulic fracture pattern. On the other hand, their findings revealed that the differential horizontal stress has no remarkable effect on the stimulated reservoir volume, but their models did not have heterogeneities such as natural fractures. Nevertheless, they highlighted that permeability has the most significant effect on the stimulated reservoir volume, and hence upon the presence of natural fractures this could lead to different results in shale plays.

Natural fractures are key aspects to consider in designing hydraulic fracturing process.[12,13,19,20] Experimentally it has been shown that the orientation of natural fractures and the magnitude of differential horizontal stress could have a significant impact on the propagation of hydraulic fractures.[2,25,3] Warpinski and Tefuel reported that hydraulic fractures are more likely to cross natural fractures at differential stresses exceeding 10 MPa where the natural fracture make angles greater than 60 degrees with the hydraulic fracture. Determining if hydraulic fractures will propagate along, or cross natural fractures is key to determining their impact on fracture propagation and gas production.

* Correspondence to: School of Engineering, University of Aberdeen, AB24 3UE Aberdeen, United Kingdom.
E-mail address: amin.sharifi@abdn.ac.uk (A. Sharifi Haddad).

https://doi.org/10.1016/j.gete.2023.100507
Received 2 June 2023; Received in revised form 7 September 2023; Accepted 29 September 2023
Available online 5 October 2023

Experimental investigations of hydraulic fracturing and natural fractures shows that natural fractures open under low differential stress.[9] Guo et al.'s study also demonstrated that the interaction of hydraulic and natural fractures is linked to the injection rate, as the injection rate increases hydraulic fractures may be more likely to cross natural fractures. Also, it has been considered advantageous to open natural fractures during stimulation to increase recovery.[14] To achieve this, the implementation of temporary plugging during hydraulic fracturing is considered.[14] However, complex fracture networks also lead to complex proppant distribution creating another uncertainty.[27] If proppant distribution is not consistent, production from parts of the fracture network may be poor especially once pressure declines.

Dahi-Taleghani and Olson conducted modelling studies on the interaction of hydraulic and natural fractures, and reported that the magnitude of the anisotropy of in-situ stress is a significant contributor to the complexity of hydraulic fracture patterns.[5] They also concluded that fracture-path complexity and width restriction distributions in complex fracture networks are an integral part of predicting well performance in naturally fractured reservoirs.[21] 3D models have also demonstrated that stress contrasts, injection rates and natural fracture properties influence the effective contact area of hydraulic fracture networks warranting careful consideration when planning stimulation.[24] Significantly, fracture height growth is better contained when the stress contrast is higher which is key when considering the integrity of reservoir seals. These models have also been used to determine the most efficient stimulation designs such as number of fractures per stage.[28] In a recent study by Li et al.[12] the effects of heterogeneities on the hydraulic fracture propagation were investigated. Different synthetic patterns of joints (natural fractures) were included in their model, and it was found that both the joints and rock matrix properties significantly influenced the hydraulic fracture propagation.

Research in this field has focussed heavily on the mechanics of propagating fractures. But for production and reservoir engineers it is not as easy to interpret what effect this will have on recovery. In other words, when developing shale resources what impact do the natural fractures have on recovery as a result of complexities that can occur for hydraulic fractures?

To maximise the efficiency of hydraulic fracturing process, studies were conducted to explore potential modifications on the hydraulic fracturing design that could lead to a better outcome than the standard practice for hydraulic fracturing.[15,20,22] In a study by Michael, it was found that achieving a desirable orientation for fracture planes during hydraulic fracturing process (transverse hydraulic fracture) depends on the formation breakdown pressure and tensile strength. It was suggested that transverse hydraulic fractures can be initiated by investigating the near wellbore geomechanical properties in each shale formation and modifying the perforation direction in the well.[15] Sherratt et al. developed a method of capturing complex fracture networks in conventional reservoir simulators.[19] They demonstrated that hydraulic fractures exploit the weak planes of natural fractures which in turn impact on the reservoir stimulated volume. It was shown that at large angles between the strike of the natural fractures and the maximum horizontal stress, the interactions between propagating hydraulic and natural fractures become predominant. In their study the natural fractures were all weak and led to a highly complex hydraulic fracture networks with lateral extensions to the well instead of deeper into the formation.

These geomechanical properties of shale formations, led to the hypothesis that a change in well orientation could achieve more successful hydraulic fracturing by penetrating fractures deeper into the formation instead of laterally along the well.[20] They reported that rather than drilling wells in shale formations in a standard orientation, changing the well direction, could result in a larger stimulated reservoir volume which in turn increases the gas recovery. It was shown that such modification can lead to the potential benefits of increasing NPV by reducing the number of required wells, and decreasing the time for NPV to become positive and therefore de-risks the investment.[20]

The previous investigations have only considered a single geomechanical case where natural fractures are very weak, and the differential horizontal stress is also very low. When hydraulic fractures intersect natural fractures, the opposing component of the maximum horizontal stress is not large enough to stop their propagation along the weak natural fractures. This creates hydraulic fracture networks that are complex and have a large component of the extension in the direction of natural fractures instead of perpendicular to the well.

As hydraulic fractures extend along the natural fracture planes, they open against a force associated with the maximum horizontal stress. Nevertheless, the magnitude of this force opposing the reopening or dilation of natural fractures depends on a few characteristics of the formation. Firstly, it depends on the orientation of the natural fracture with respect to state of the in-situ stresses. This becomes more complex as the stress-state during fracturing is altered by stress shadow effects of previous fracturing stages.[26] The stress state varies even more complexly when there are interactions between different wells.[22,4] Secondly, the magnitude of the differential horizontal stress is critical for the propagation of fractures. Previous fracture modelling studies have shown that the crack properties such as aperture and flow rate increase with far-field differential stress state.[16] In addition, the natural fracture toughness opposes the tip of propagation. The complex behaviour of interacting hydraulic and natural fractures have been investigated to determine the crossing behaviour under different fracture toughness conditions concluding it can change the interaction from crossing to slipping.[31] However, this outcome is abstract to a production engineer and the impact on gas recovery and required well spacing is not specified.

Therefore, in this study, we aim to explore the effects of differential in-situ horizontal stress and the toughness of natural fracture on the hydraulic fracture patterns. Although the effect of in-situ stresses on the hydraulic fracture patterns is well understood, their effect in the presence of natural fractures is less well studied. As the differential stress gets larger, there is a larger force opposing the opening of hydraulic fractures along existing natural fractures with a component of the maximum horizontal stress on them. Under different fracture toughness conditions propagating along existing natural fractures will also require more or less energy. Therefore, as these conditions change it will alter the interaction of hydraulic and natural fractures. This study will help to identify operational windows within which drilling wells in a modified orientation can increase the stimulated reservoir volume.

2. Method

In this study we used the unconventional fracture model (UFM) which is available as part of the Kinetix software to model hydraulic fracture propagation in the presence of natural fractures.[18] Then to upscale the fracture network for flow modelling purposes we used the Fracture Upscaling Method (FUM) that was introduced by[19].

In our study, a reservoir volume between the two parallel horizontal wells in the formation with a constant well spacing of 300 m can be considered for the numerical analysis, this will be referred to as the Production Volume as shown as the orange zone in Fig. 1. The recovery

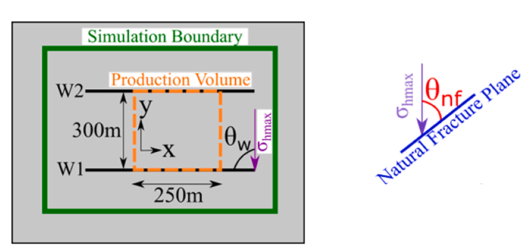

Fig. 1. Region of investigation for both the hydraulic fracture modelling and gas production.

from the formation between 250 m long sections of the wells can give an indication of the recovery from the region between two full wells while reducing the computational time for the purpose of this study. These both reduce the computational expense of simulations and speed up the simulation time. This is important as the natural fracture distributions are generated using a statistical distribution which requires multiple realisations to be generated, to create an average production profile.

The well orientation, θ_w, is the angle between the direction of maximum horizontal stress and the well. Hydraulic fractures should ideally extend perpendicular to the well therefore, hydraulic fractures create a zone between the neighbouring wells shown as the Production Volume in Fig. 1. For example, when considering well 1 (W1), hydraulic fractures propagate towards well 2 (W2) as well as in the opposite direction away from W2. Hydraulic fracturing is modelled over a larger area than the production volume up to the Simulation Boundary as shown in Fig. 1 to account for this, and the simulation boundary is far from the tips of hydraulic fractures. Shale resources are typically developed using arrays of many parallel wells. As a result, the recovery from just the area between the two wells can be considered and multiplied by the area of a field to predict field recovery.

It is assumed that natural fractures intersect the full depth of the shale formation in a vertical plane. The natural fractures are represented in this study by synthetic realisations created and distributed using a deterministic method. Each realisation of natural fractures can be defined by the mean natural fracture length, L_{nf}, the mean natural fracture spacing, S_{nf}, and the mean orientation, θ_{nf}, which is the angle between the natural fractures and the direction of σ_{hmax}. Each realisation of natural fractures is unique and therefore multiple realisations were generated for each scenario, and executed through the stimulation, upscaling, and production simulation workflow to find an average gas recovery.

In this study the natural fracture orientation $\theta_{nf} = 80^\circ$ is used because in a previous study it was shown this orientation results in highly complex fracture networks which results in reduced recovery.[20] This orientation was also previously demonstrated to be an ideal candidate for changing the well orientation. Natural fracture spacing could increase the impact of hydraulic fracture propagation as spacing decreases. Small fracture spacing and large fracture length have a significant impact on hydraulic fracture patterns, therefore we used $L_{nf} = 30m$ and $S_{nf} = 10m$ in this study.

Firstly, the impact of the differential horizontal stress and fracture toughness on hydraulic fractures propagation and production from these fracture networks will be studied independently. The impact of both together will also be tested to determine the impact on hydraulic fracture propagation under different geological conditions. Finally, changing the well orientation under different conditions will be tested to determine the range of differential horizontal stress and fracture toughness over which changing the well orientation is beneficial.

2.1. Hydraulic fracture propagation modelling

Through using hydraulic fracture modelling software (Kinetix) we can capture the interactions between hydraulic and natural fractures which is the core aim of this study.

To create the hydraulic fracture networks for our study, we used the well and stimulation designs that are from a field case study from North American as input to Kinetix, these details are shown in Table 1.[29] The reservoir properties that are required in the hydraulic fracture propagation modelling are provided in Table 2 and the reservoir is assumed to be homogenous.

2.2. Fracture upscaling

Conventional reservoir simulation software represents the reservoir commonly as a grid composed of regular rectangular cells with permeability defined in each of the axis directions orthogonal to cell faces with neighbouring cells. Representing the effect of complex hydraulic fractures modelled using the unconventional fracture model previously discussed within this reservoir simulation grid to simulate production represents a challenge. The Fracture Upscaling Method was used in this study, it alters the properties of a dual permeability reservoir simulation grid using a given discrete fracture network.[19]

The fracture permeability in a cell, k_f is given by the equation below.

$$k_f = \alpha \frac{w_f^2}{12} \begin{pmatrix} \left| \widehat{n}_f \times (e_x \times \widehat{n}_f) \right| \frac{A_{fx}}{A_x} \\ \left| \widehat{n}_f \times (e_y \times \widehat{n}_f) \right| \frac{A_{fy}}{A_y} \\ \left| \widehat{n}_f \times (e_z \times \widehat{n}_f) \right| \frac{A_{fz}}{A_z} \end{pmatrix} \tag{1}$$

This equation calculates the cell permeability based on the fracture aperture, w_f, the average plane normal vector $\widehat{n}_f$ and fracture area on each cell faces A_{fx},A_{fy} and A_{fz}. An $\alpha = 2 \times 10^{-5}$ is used to account for the presence of proppant in the fractures which blocks some of the fractures and therefore reduces permeability.[29] The other terms in this equation represent grid properties. The cell face areas are given by A_x, A_y and A_z and the grid axis unit vectors are given by e_x, e_y and e_z (more details can be found in [19]).

In our study a single layer thickness grid was considered. The results are output as a simulation grid ready to be used in a conventional reservoir simulator. The discrete fracture models produced using Kinetix are no longer needed as they are captured in the altered reservoir simulation grid.

2.3. Production modelling

To model the production of gas from the simulation grid produced using the simulation grid output by the fracture upscaling method a reservoir simulation software is required. The commercial reservoir

Table 1
Well and stimulation design based on.[29]

Property	Value
Well section length (m)	250
Hydraulic fracture stages per well	3
Fracture stage spacing (m)	47
Perforation clusters per stage	4
Perforation cluster spacing (m)	16
Volume of injected slickwater per well (m^3)	1300
Mass of proppant injected per well (kg)	198,000
Injection rate (m^3/min)	47

Table 2
Properties of the reservoir used for propagation modelling of hydraulic fracturing.[20]

Property	Value
Permeability (mD)	0.0008
Porosity	0.12
Formation thickness (m)	25
Maximum Horizontal Stress (kPa)	51,200
Minimum Horizontal Stress (kPa)	48,263
Initial Reservoir Pressure (kPa)	31,026
Poisson Ratio	0.23
Young's Modulus (kPa)	2.06×10^7
Natural Fracture Coefficient of Fraction (-)	0.6
Natural Fracture Toughness ($kPa.m^{\frac{1}{2}}$)	550
Shale Gas Composition	CH_4

simulator CMG-GEM is used to model production as it can represent many different complexities of hydrocarbon transport phenomena in shale formations. Some of the reservoir properties used to model fluid flow such as permeability and porosity have already been defined when modelling fracture propagation and are detailed in Table 2.

Shale formations exhibit a pressure dependant permeability and therefore a permeability modulus is used to modify the permeabilities.[17]

$$k_m = k_{mi} e^{-\gamma_m (P_{mi} - P_m)} \tag{2}$$

$$k_f = k_{fi} e^{-\gamma_f (P_{fi} - P_f)} \tag{3}$$

These relationships alter the matrix and fracture permeabilities, k_m and k_f respectively, from their original values k_{mi} and k_{fi} at the initial pressure of the reservoir. and γ_m and γ_f are the permeability moduli. Gas flow in fractures also requires a non-Darcy modifier to be applied. To account for non-Darcy flow in fractures, the Forchheimer correction is used, and non-Darcy parameters are given in Table 3.[7,8]

To account for slip flow of the gas in the matrix, a Klinkenberg correction, P_{kr} is used.[11] Also, gas desorption is modelled by using a Langmuir isotherm with the details provided in Table 3.[1,10] The values provided in this table, are based on the outcome from a history matched model.[20]

Gas production is controlled by a bottom hole pressure (BHP) schedule adapted from a field case[29] in both wells and it is illustrated in Fig. 2. The relative permeabilities for matrix and fracture in this study are shown in Fig. 3.

The simulation gird consists of a total of 125 × 150 × 1 cells with dimensions of 2 m × 2 m × 25 m. Sensitivity tests on the dimensions showed that these dimensions provide accurate results.[19,20] All simulations were performed on a desktop computer with 6 CPU cores (Intel Xeon E5645) at 2.40 GHz, and 64 Gb of RAM. Computational time for each case of hydraulic fracture propagation was around half an hour, and the modelling of 5000 days of gas production using the upscaled grid took between half an hour to one hour using CMG-GEM.

3. Results and discussion

3.1. Effect of differential horizontal stress

To explore the effect of the differential horizontal stress on hydraulic fracture patterns, hydraulic fracture propagation was modelled for different in-situ stress states. Therefore, minimum horizontal stresses ranging from $\sigma_{h,\min} = 40,000kPa$ to $56,000kPa$ were used with the differential horizontal stress varying from $\Delta\sigma_h = 4,137kPa$ up to a maximum of $\Delta\sigma_h = 20,685kPa$. The well orientation is kept in the same direction as the minimum horizontal stress ($\theta_w = 90°$). A constant natural fracture strength of $550kPa \bullet m^{1/2}$ is used representing a partially cemented natural fracture. The hydraulic fracture patterns are shown in Fig. 4 under both high and low differential horizontal stresses.

Table 3
Reservoir and fluid properties.[20]

Property	Value
Matrix permeability modulus, γ_m (kPa^{-1})	4.35×10^{-6}
Fracture permeability modulus, γ_f (kPa^{-1})	4.35×10^{-5}
Maximum adsorbed gas, $q_{CH4,\max}$ (mol/kg)	0.23
Langmuir isotherm(CH_4) (kPa^{-1})	2.9×10^{-4}
P_{kr} (kPa)	500
Non – Darcy modifier$\alpha_g (m^{-1})$	4.76×10^9
Non – Darcy modifier $N1_g$ (-)	1.021
Initial water saturation in fracture (-)	1.0
Initial water Saturation in matrix (-)	0.10
Shale density $(kg.m^{-3})$	1992
Fracture porosity (-)	0.001
Reservoir Temperature (℃)	55

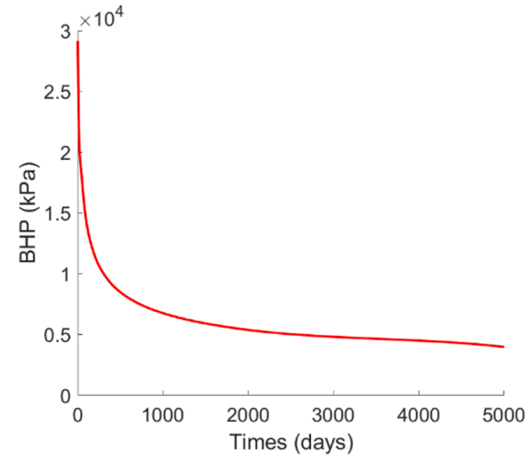

Fig. 2. Bottom hole pressure (BHP) schedule in production wells (adopted from Sherratt et al. [20]).

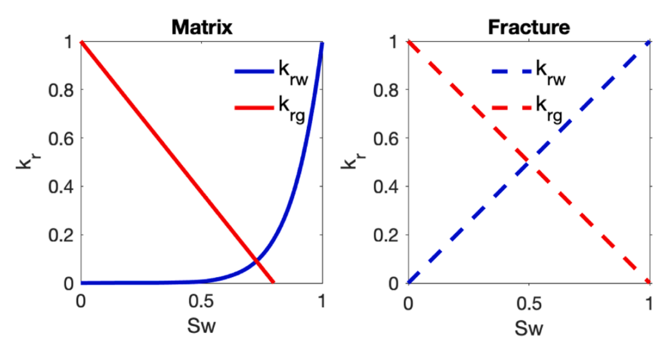

Fig. 3. Relative permeability curves for the matrix and fracture in shale formations.[6]

This shows that under high differential horizontal stress, hydraulic fractures extend perpendicular to the well and cross natural fractures instead of reorienting and following the plane of natural fractures. While in the low differential stress case, hydraulic fracture networks are highly complex and branched, this results in poor connectivity with the formation deepest between the two wells. As a result, Fig. 5a shows that the pressure deep in the formation after 2000 days is still nearly 30,000 kPa and almost unchanged since the start of production. Nevertheless, at the high differential stress the pressure is reduced everywhere in the formation.

This process can be shown in Fig. 6 which illustrates hydraulic fractures initiate in the same direction as the maximum horizontal stress (Fig. 6i) and they continue propagating in this direction until they intersect a natural fracture (Fig. 6 ii). What happens next depends on what is most efficient. The hydraulic fractures can either propagate along the natural fractures (iii) or cross them (iv). This has been studied extensively in previous fracture modelling and can be captured in fracture modelling software.[31] Crossing the natural fractures results in simple fractures that extend deeper into the formation perpendicular to the direction of the well. However, if hydraulic fractures reorient and follow the plane of natural fractures, then complex fracture networks will be created with a component of the extension parallel to the direction of the well.

This means that at higher differential horizontal stress, a higher maximum horizontal stress is exerted on the natural fracture opposing the hydraulic fracture propagating along it. This results in hydraulic fractures that propagate mainly perpendicularly to the well into the formation instead of laterally along the well. The gas production as a function of differential horizontal stress for different minimum

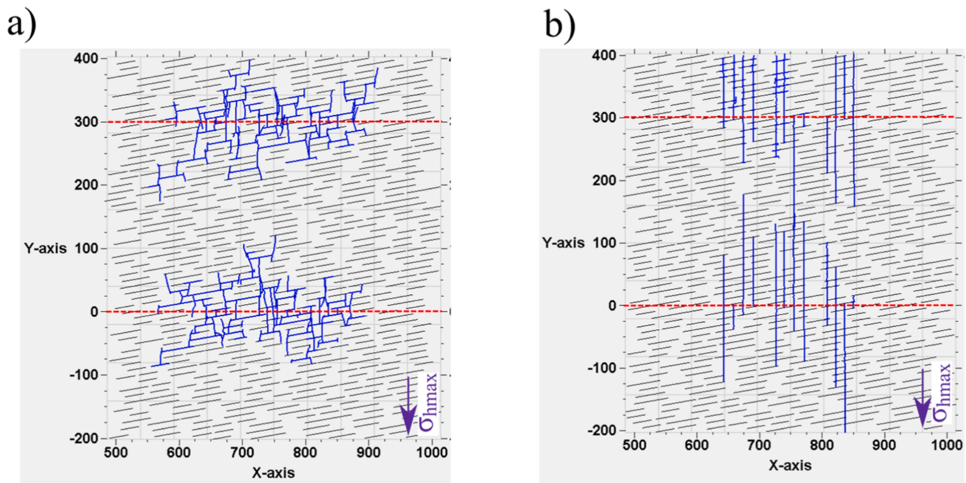

Fig. 4. Hydraulic fracture propagation under $\sigma_{h,\min} = 44000kPa$ and a) $\Delta\sigma_h = 4137kPa$ and b) $\Delta\sigma_h = 16458kPa$.

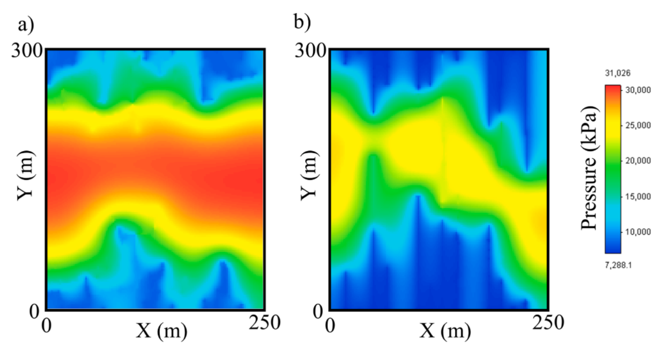

Fig. 5. Reservoir pressure after 2000 days of production under under $\sigma_{h,\min} = 44000kPa$ and a) $\Delta\sigma_h = 4137kPa$ and b) $\Delta\sigma_h = 16458kPa$.

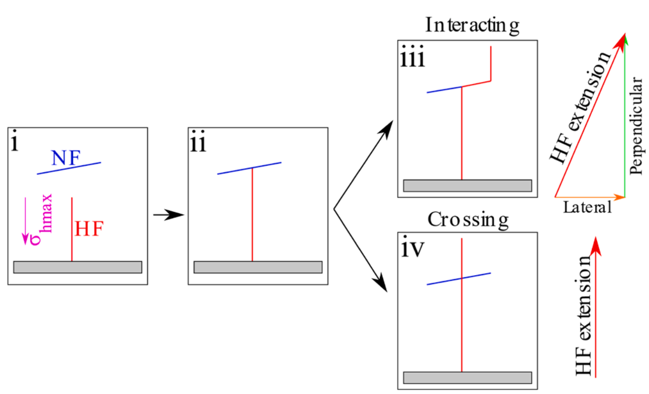

Fig. 6. Schematic showing both interacting and crossing hydraulic fracture behaviour with natural fractures.

horizontal stress conditions is shown in Fig. 7 after 500, 1000 and 2000 days. In Fig. 8, we compared the gas production after 2000 days under different minimum horizontal stresses and differential horizontal stresses.

This shows that for all cases, as the differential stress increases recovery also eventually increases significantly. However, they all show a trend of recovery reducing initially as the differential stress increases. This may be explained as the small increase still results in hydraulic fractures propagating along natural fractures but the increased resistance results in less extensive fracture networks with reduced aperture limiting the ability of gas to flow back to the well. For all cases after 2000 days with $\Delta\sigma_h = 4137kPa$ gas production is less than $2.75 \times 10^7 sm^3$ which increases to a cumulative volume between $3.25 \times 10^7 sm^3$ and $4.5 \times 10^7 sm^3$ as differential horizontal stress increased up to $\Delta\sigma_h = 20,685kPa$. It also shows that a larger increase in differential stress is required to change the behaviour as $\sigma_{h,\min}$ increases.

Fig. 7 and Fig. 8 also show that there is a small decrease in recovery for small increases in $\Delta\sigma_h$. This is most likely a result of the increased opposition to hydraulic fractures propagating along natural fractures. In other words, there is a transition for the dominance of differential horizontal stress over the natural fracture effects, it is still easier for fractures to reorient and follow the plane of natural fractures rather than crossing them resulting in interacting rather than crossing behaviour.

To summarise, these results show that when hydraulically fracturing the naturally fractured formations under low differential horizontal stress, highly complex hydraulic fracture networks are created that do not propagate deep into the formation. This will have an impact on the field development of naturally fractured shale formations as low differential horizontal stresses will require tighter well spacing than an identical formation under greater differential horizontal stress. Thus, under a high differential horizontal stress, the effect of natural fractures is insignificant and could be ignored when designing the hydraulic fracturing process.

3.2. Effect of natural fracture toughness

The toughness of natural fractures represents the resistance of the natural fracture when hydraulic fractures propagate along them. This shows the difference between an open natural fracture which would have 0 fracture toughness, and a sealed fracture with very high fracture toughness and everything in between. To explore the impact of toughness of natural fractures on the hydraulic fracture patterns a range of toughnesses from $0kPa \bullet m^{1/2}$ to $3500kPa \bullet m^{1/2}$ with $\sigma_{h,\min} = 44000kPa$ and different values of differential horizontal stress $\Delta\sigma_h$ were considered.

Fig. 9 shows the fracture networks that are developed for two cases of high fracture toughness of $3500kPa \bullet m^{1/2}$ and low fracture toughness of $1000kPa \bullet m^{1/2}$ with $\Delta\sigma_h = 4137kPa$.

This shows that as fracture toughness increases, the resistance of hydraulic fractures propagating along the plane of natural fractures increases, and therefore they cross the natural fractures rather than propagating along their direction. This leads to hydraulic fractures that extend into the formation instead of propagating along laterally along the well, which in turn increase the recovery from the reservoir. The effect of fracture toughnesses on the cumulative gas production is shown in Fig. 10.

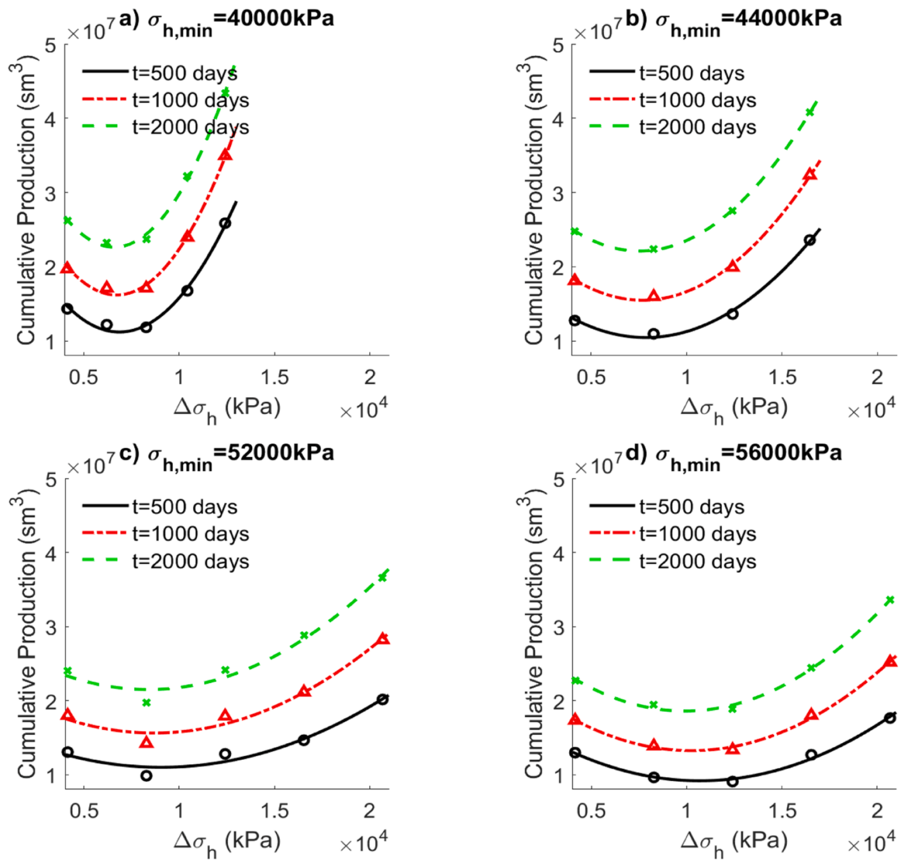

Fig. 7. Cumulative gas production after 500, 1000 and 2000 days under different differential horizontal stresses and minimum horizontal stresses.

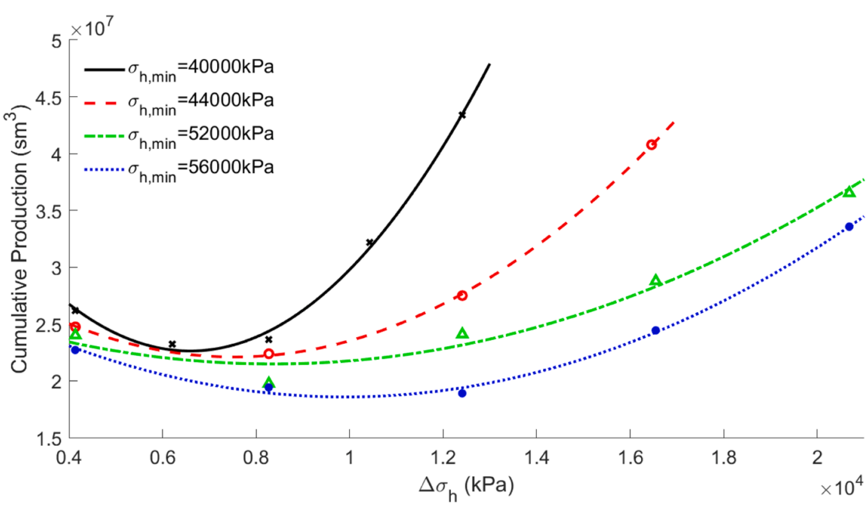

Fig. 8. Cumulative gas production after 2000 days under different stress conditions.

This shows that under a low natural fracture toughness the recovery is low and less than 3×10^7 sm^3 after 2000 days production for all cases. As fracture toughness increases there is an increasing trend for gas production that reaches to above4 $\times 10^7$ sm^3 after 2000 days of production for all cases. The gas production after 1000 days for all cases is shown in Fig. 11.

It demonstrates the fracture toughness range over which the increasing gas production occurs. This indicates the values of fracture toughness for different values of differential horizontal stress with a minimum horizontal stress of $\sigma_{h,\min} = 44000kPa$. As the differential horizontal stress increases, the crossing phenomena of hydraulic fractures through natural fractures starts becoming dominant at lower values of differential horizontal stress.

These outcomes demonstrate that the natural fracture toughness must be considered when planning hydraulic fracturing in naturally fractured shale formations. Low natural fracture toughness is more likely to lead to the development of highly complex hydraulic fracture networks that will require smaller well spacing to achieve efficient recovery from the formation. However, high natural fracture toughness will result in more crossing behaviour and therefore they will have less of an impact on hydraulic fracture propagation.

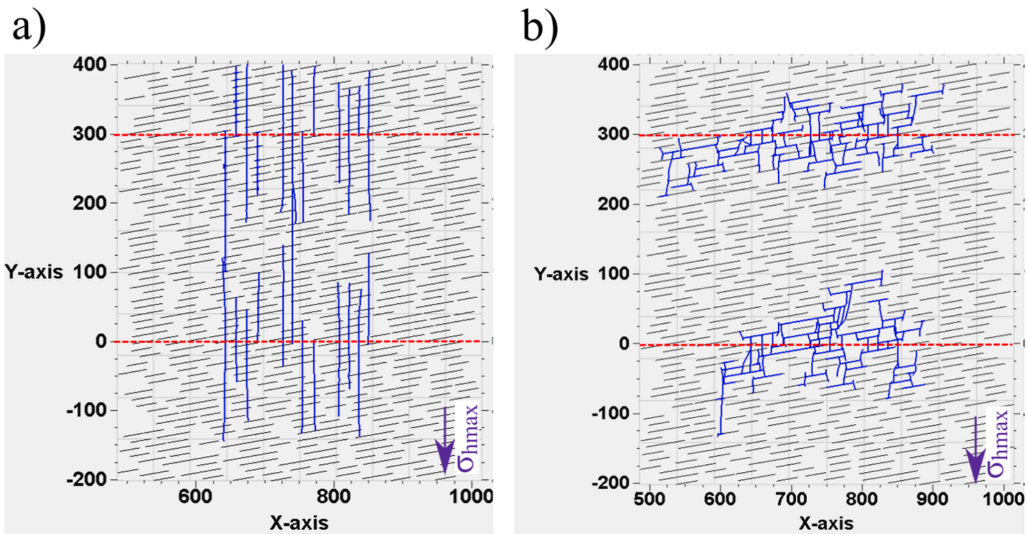

Fig. 9. Hydraulic fracture propagation with a) high natural fracture toughness $3500 kPa \bullet m^{1/2}$ and b) low natural fracture strength $1000 kPa \bullet m^{1/2}$ with $\sigma_{h,\min} = 44000 kPa$ and $\Delta\sigma_h = 4137 kPa$.

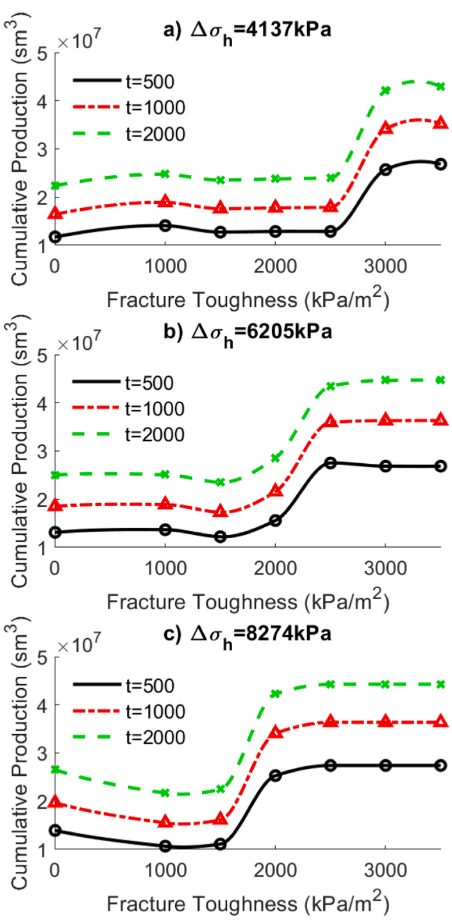

Fig. 10. Cumulative gas production with different natural fracture toughness and a) $\Delta\sigma_h = 4137 kPa$, b) $\Delta\sigma_h = 6205 kPa$ and c) $\Delta\sigma_h = 8274 kPa$ and $\sigma_{h,\min} = 44000 kPa$.

3.3. Effect of changing well orientation

It was previously reported that drilling wells in a different orientation than the standard practice could increase the stimulated reservoir

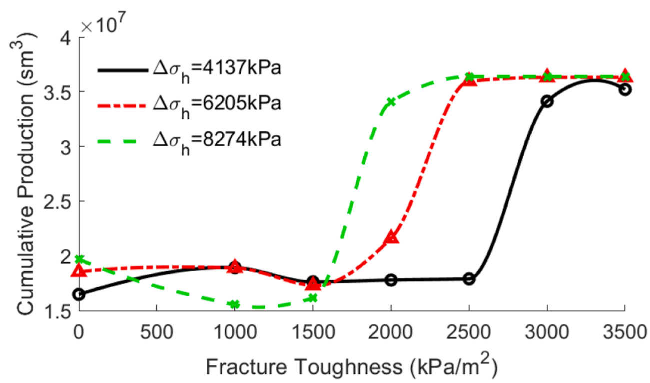

Fig. 11. Cumulative gas production after 1000 days for different fracture toughnesses and differential horizontal stress $\Delta\sigma_h$ with $\sigma_{h,\min} = 44000 kPa$.

volume in hydraulic fractured wells.[20] However, the maximum horizontal stress in such cases is not large enough to impose resistance against opening the planes of natural fractures by hydraulic fractures.

The results presented in our study so far have shown that increasing both the differential horizontal stress and the natural fracture toughness have the effect of increasing the resistance against fractures propagating along natural fractures. Therefore, under different geological and geomechanical conditions hydraulic fractures may not exploit the plane of natural fractures and the orientation of hydraulic fractures is mainly controlled by the direction of maximum horizontal stress. This means that changing the orientation of the well in naturally fracture formations will be favourable in some geological and geomechanical conditions.

To test the impact of both parameters on hydraulic fracture propagation, simulations were run using the industry standard well orientation ($\theta_w = 90°$), with differential horizontal stresses from $\Delta\sigma_h = 1000 kPa$ to $\Delta\sigma_h = 10000 kPa$ and natural fracture toughness from 0 to 4000 $kPa \bullet m^{1/2}$. Fig. 12 shows the cumulative production after a) 500 days, b) 1000 days and c) 2000 days under a variety of fracture strengths and differential stresses. The minimum stress in all cases is $\sigma_{h,\min} = 48263 kPa$..

This shows that recovery is greatest when differential stress and fracture toughness are both high. This is a result of the hydraulic fractures displaying crossing tendencies rather than interacting with the natural fractures and propagating along them as demonstrated in

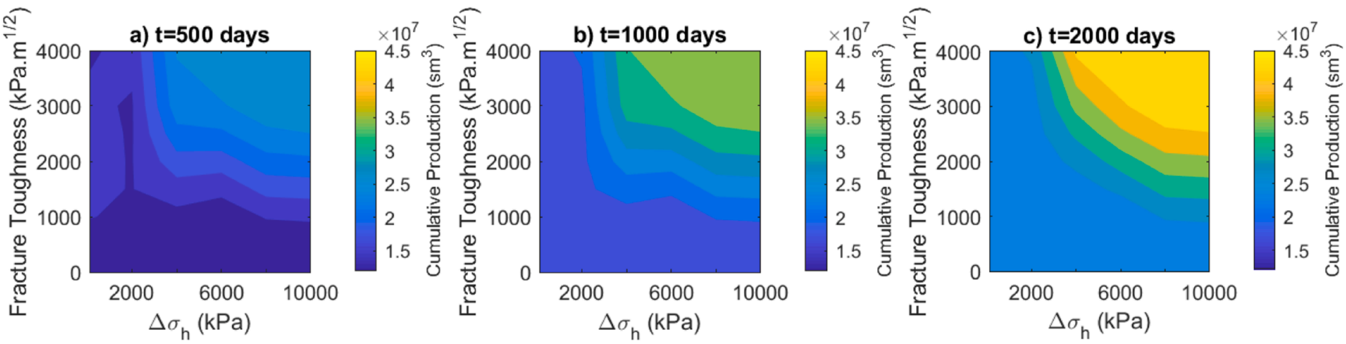

Fig. 12. Cumulative gas production as a function of differential stresses and fracture toughnesses after a) 500 days, b) 1000 days and c) 2000 days using the standard well orientation and $\sigma_{h,\min} = 48263kPa$.

Sections 3.1 and 3.2. This demonstrates the range of natural fracture toughnesses and differential horizontal stresses under which the natural fractures have the largest effect on recovery. In the regions where recovery is high, this suggests that natural fractures are having limited impact on the propagation of hydraulic fractures and therefore their characteristics are less important as they do not interfere with hydraulic fracturing process. On the other hand, in the region where recovery is very low this suggests that the natural fractures will have a remarkable influence on the propagation of hydraulic fractures and therefore more attention should be paid in properly defining them.

To understand the role of changing the well orientation, simulations were conducted for the same scenarios but with a well orientation of $\theta_w = 70^\circ$. This is a 20° change from the industry standard practice which was suggested by Sherratt et al. [20] The cumulative recovery is shown in Fig. 13 and displays a similar trend as in Fig. 12 where the standard well orientation was used. As the differential stress and fracture toughness increase, the gas recovery also increases.

Fig. 14 shows the difference between the recovery with the new well orientation $\theta_w = 70^\circ$ (Fig. 13) and the standard orientation ($\theta_w = 90^\circ$) (Fig. 12). This illustrates the conditions in which the change in well orientation increases recovery (red colour) and the cases which lead to a decrease in recovery (blue colour).

Fig. 14 shows that the stimulated reservoir volume and consequently recovery can be increased by drilling wells in a modified direction when both the differential horizontal stress and fracture toughness are low. The results suggest that when fracture toughness is under 1000 $kPa \bullet m^{1/2}$ with a differential horizontal stress up to 8000 kPa, a modified well orientation leads to higher recovery compared to a well that is drilled in a standard direction. Furthermore, with a differential horizontal stress under 2000 kPa a change in orientation is beneficial for all fracture toughnesses. These regions that show an increase in recovery are shown in Fig. 15 as the orange region.

The window of differential horizontal stress and natural fracture toughness that represents the greatest opportunity for increasing recovery by changing the well orientation is characterised by low differential horizontal stresses and low fracture toughness. This suggests that in this orange region the hydraulic fractures are interacting with natural fractures within the reservoir. But outside of this region, the geomechanical properties in the reservoir are opposing hydraulic fractures extending along the plane of natural fractures. Thus, the natural fractures have a large impact on the resulting trend of the orientation of the hydraulic fractures.

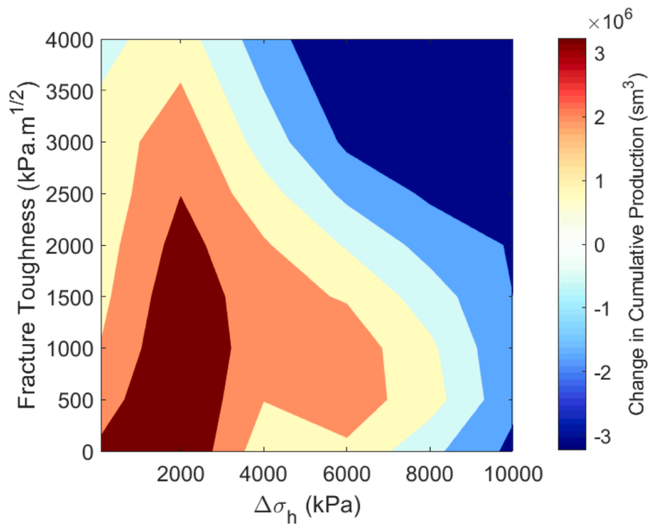

Fig. 14. The change in cumulative production between the standard well orientation and the deviated well with different differential stresses and fracture toughnesses after 2000 days.

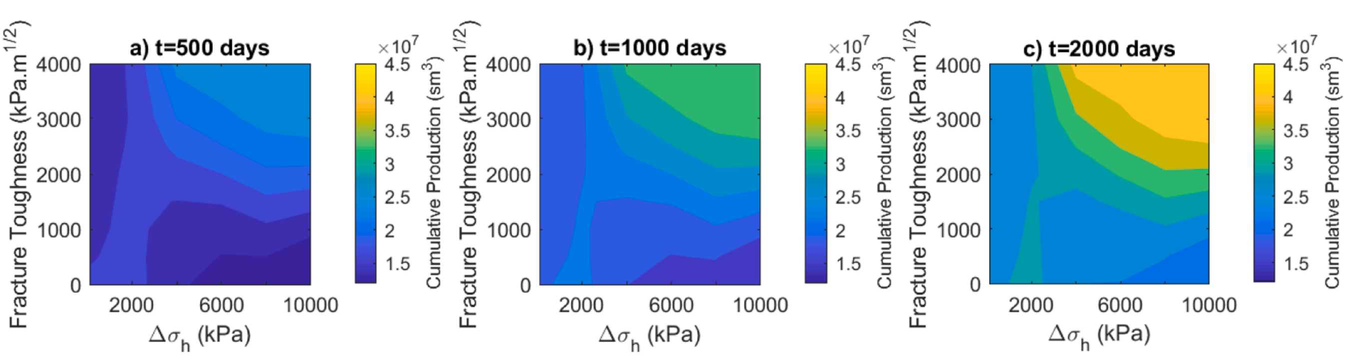

Fig. 13. Cumulative gas production as a function of differential stresses and fracture toughnesses after a) 500 days, b) 1000 days and c) 2000 days using a well orientation of 70 degrees.

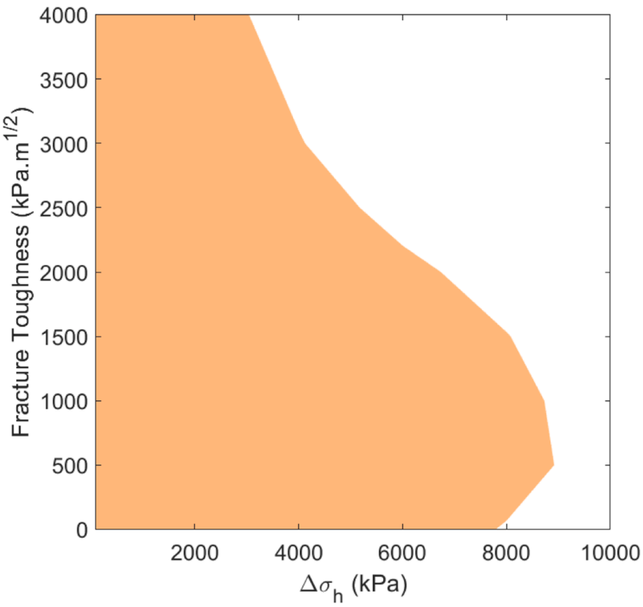

Fig. 15. The region in orange colour demonstrates changing the well orientation is beneficial (based on $\sigma_{h,\min} = 48263kPa$ and 2000 days of production).

The outcome of this study shows that drilling wells in a modified direction should only be considered if the hydraulic fractures are expected to exploit natural fractures when differential horizontal stress or fracture toughness are low.

In our study, a single natural fracture geometry in terms of orientation, spacing and length is considered. The behaviour of hydraulic fractures interacting with natural fractures is also impacted by the direction of natural fractures and hence different orientation may have a different window over which well orientation change is beneficial. In addition, larger fracture length and smaller spacing can magnify their effect of natural fracture on the propagation of hydraulic fractures. The strength of the unfractured formation may also have a similar impact. Furthermore, the stimulation scheme can be optimised under different geological conditions including the injection rate, volumes, and proppant types. The effects of these variables were not investigated in this study and are important to consider when determining economic viability.

4. Conclusions

This study explored the effects of differential in situ stress and natural fracture toughness on the propagation of hydraulic fractures in naturally fractured formations. It was found that hydraulic fractures only reorient and follow the plane of existing natural fractures when the differential horizontal stress and fracture toughness are low. At larger differential horizontal stress and fracture toughness values, the fracture networks become simpler as the propagating hydraulic fractures extend across natural fractures rather than being influenced by the direction of natural fractures. Therefore, there is a window of natural fracture toughness and in situ differential horizontal stress where a well orientation change is beneficial. This means we can achieve a favourable hydraulic fracture networks that extend deep into the formation and provide a larger stimulated reservoir volume and consequently an increased recovery. Therefore, it is recommended that modifying the direction of drilling wells should be investigated carefully considering the reservoir geomechanical properties.

CRediT authorship contribution statement

Joseph Sherratt: Investigation, Methodology, Software, Validation, Visualization, Data curation, Formal analysis, Writing - original draft. **Amin Sharifi Haddad:** Conceptualization, Methodology, Funding acquisition, Supervision, Formal analysis, Project administration, Writing – review & editing. **Roozbeh Rafati:** Formal analysis, Validation, Supervision, Writing - review & editing.

Declaration of Competing Interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

Data availability

Data will be made available on request.

Acknowledgements

The authors would like to thank the School of Engineering at the University of Aberdeen for financial support and providing the required facilities to complete the study. Support from the Computer Modelling Group and Schlumberger for the use of their software packages is greatly acknowledged. This research did not receive any specific grant from funding agencies in the public, commercial, or not-for-profit sectors.

References

1. Arri LE, Yee D, Morgan WD, Jeansonne MW. *Modeling Coalbed Methane Production With Binary Gas Sorption*. Casper, Wyoming: Society of Petroleum Engineers,; 1992.
2. Blanton, T. 1982, An experimental study of interaction between hydraulically induced and pre-existing fractures. In: *Proceedings of the Presented at the SPE Unconventional Gas Recovery Symposium*, Pittsburgh, Pennsylvania.
3. Blanton, T. 1986, Propagation of hydraulically and dynamically induced fractures in naturally fractured reservoirs. In: *Proceedings of the Presented at the SPE Unconventional Gas Technology Symposium*; May 1986 Louisville, Kentucky.
4. Chen X, Li Y, Zhao J, Xu W, Fu D. Numerical investigation for simultaneous growth of hydraulic fractures in multiple horizontal wells. *J Nat Gas Sci Eng*. 2018;vol. 51: 44–52.
5. Dahi-Taleghani A, Olson JE. Numerical Modeling of Multistranded-Hydraulic-Fracture Propagation: Accounting for the Interaction Between Induced and Natural Fractures. *SPE J*. 2011;16(3):575–581.
6. Daigle, H., Ezidiegwu, S. , Turner, R. 2015, Determining relative permeability in shales by including the effects of pore structure on unsaturated diffusion and advection. In: *Proceedings of the* Presented at the SPE Annual Technical Conference and Exhibition, Houston, Texas, USA.
7. Evans RD, Civan F. *Characterization of Non-Darcy Multiphase Flow in Petroleum Bearing Formations*. US DOE, Contract No. DE-AC22-90BC14659, School of Petroleum and Geological Engineering, University of Oklahoma,; 1994.
8. Forchheimer P. Wasserbewegung durch Boden. *Z Ver Dtsch Ing*. 1901;45:1782–1788.
9. Guo T, Zhang S, Qu Z, Zhou T, Xiao Y, Gao J. Experimental study of hydraulic fracturing for shale by stimulated reservoir volume. *Fuel*. 2014;128:373–380.
10. Hall, F.E., Chunhe, Z., Gasem, K.A.M., Robinson, R.L. , Dan, Y. 1994, Adsorption of pure methane, nitrogen, and carbon dioxide and their binary mixtures on wet fruitland coal. In: *Proceedings of the Presented at the SPE Eastern Regional Meeting*, Charleston, West Virginia.
11. Letham EA, Bustin RM. Klinkenberg gas slippage measurements as a means for shale pore structure characterization. *Geofluids*. 2016;16(2):264–278.
12. Li M, Guo P, Stolle D, Liu S. Modeling method for rock heterogeneities and multiple hydraulic fractures propagation based on homogenization approach and PHF-LSM. *Geomech Energy Environ*. 2023;33, 100442.
13. Liu Z, Chen M, Zhang G. Analysis of the influence of a natural fracture network on hydraulic fracture propagation in carbonate formations. *Rock Mech Rock Eng*. 2014; 47(2):575–587.
14. Lu C, Luo Y, Li J, et al. Numerical analysis of complex fracture propagation under temporary plugging conditions in a naturally fractured reservoir. *SPE Prod Oper*. 2020;vol. 35(04):775–796.
15. Michael A. A hybrid data-driven/physics-based modelling approach for hydraulic fracture initiation and early-phase propagation in shale. *Geomech Energy Environ*. 2023;34, 100453.
16. Nasehi MJ, Mortazavi A. Effects of in-situ stress regime and intact rock strength parameters on the hydraulic fracturing. *J Pet Sci Eng*. 2013;108:211–221.
17. Pedrosa, O.A. 1986, PressurE Transient Response in Stress-sensitive Formations. In: *Proceedings of the* SPE California Regional Meeting. SPE-15115-MS.
18. Petrel Kinetix Schlumberger, Release Date: March 2017, Kinetix Shalre for Petrel 2016.1, version 5.0.
19. Sherratt J, Sharifi Haddad A, Rafati R, Manzari MT. A fracture upscaling method (FUM) for hydraulically fractured reservoirs: From discrete fracture modelling to finite difference simulations. *J Nat Gas Sci Eng*. 2020;83, 103611.

20. Sherratt J, Sharifi Haddad A, Wejzerowski F, Rafati R. Optimising well orientation in hydraulic fracturing of naturally fractured shale gas formations. *J Nat Gas Sci Eng*. 2021;94, 104141.
21. Taleghani AD, Olson JE. How natural fractures could affect hydraulic-fracture geometry. *SPE J*. 2013;19(01):161–171.
22. Tang X, Zhu H, Wang H, Li F, Zhou T, He J. Geomechanics evolution integrated with hydraulic fractures, heterogeneity and anisotropy during shale gas depletion. *Geomech Energy Environ*. 2022;31, 100321.
23. Wang H. Numerical investigation of fracture spacing and sequencing effects on multiple hydraulic fracture interference and coalescence in brittle and ductile reservoir rocks. *Eng Fract Mech*. 2016;157:107–124.
24. Wang, J., Lee, H.P., Li, T. , Olson, J.E. 2020, Three-dimensional analysis of hydraulic fracture effective contact area in layered formations with natural fracture network. In: *Proceedings of the Fifty Fourth U.S. Rock Mechanics/Geomechanics Symposium* . ARMA-2020–1967.
25. Warpinski NR, Teufel LW. Influence of geologic discontinuities on hydraulic fracture propagation (includes associated papers 17011 and 17074). *J Pet Technol*. 1987;39 (02):209–220.
26. Wasantha PLP, Konietzky H, Xu C. Effect of in-situ stress contrast on fracture containment during single- and multi-stage hydraulic fracturing. *Eng Fract Mech*. 2019;205:175–189.
27. Wen Q, Wang S, Duan X, Li Y, Wang F, Jin X. Experimental investigation of proppant settling in complex hydraulic-natural fracture system in shale reservoirs. *J Nat Gas Sci Eng*. 2016;33:70–80.
28. Wu K, Olson JE. Numerical investigation of complex hydraulic-fracture development in naturally fractured reservoirs. *SPE Prod Oper*. 2016;31(04):300–309.
29. Yu W, Hu X, Wu K, Sepehrnoori K, Olson JE. Coupled fracture-propagation and semianalytical models to optimize shale gas production. *SPE Reserv Eval Eng*. 2017; 20(04):1004–1019.
30. Zhang K, Chen M, Wang S, Li J, Taufiqurrahman M. Significant effect of the rock parameters of Longmaxi formation in hydraulic fracturing. *Geomech Energy Environ*. 2023;32, 100384.
31. Zhao Y, Zhang YF, He PF. A composite criterion to predict subsequent intersection behavior between a hydraulic fracture and a natural fracture. *Eng Fract Mech*. 2019; 209:61–78.