Hydraulic Fracture Propagation and Analysis in Heterogeneous Middle Eastern Tight Gas Reservoirs: Influence of Natural Fractures and Well Placement

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ABSTRACT: Hydraulic fracturing is a stimulation process, most frequently used in tight and unconventional reservoirs for successful and economical hydrocarbon production. This study deals with the propagation behavior of induced hydraulic fractures (HFs) in naturally fractured formations within heterogeneous Middle Eastern tight gas reservoirs. Local sensitivity analysis was conducted for a Middle East candidate reservoir by varying fracture design parameters to investigate the fracture propagation behavior. After a comprehensive evaluation, a discrete fracture network-based simulator was used to introduce multiple sets of natural fractures (NFs) into the model to further analyze their interactions. Furthermore, simplistic wellbore placement analysis was also conducted. It is observed that production in tight reservoirs is governed by the presence of NFs and their distribution. This investigation analyzes HF propagation behavior and its correlated effects in the presence of NFs. Further assessment in terms of varying fracture geometry, NF sets, wellbore placement, and their effects on the conductivity are also presented. The introduced NF sets further illustrate the significance of the NF properties in this assessment. Additionally, variations in well placement demonstrate how effective the treatment can be in the presence of complex NF sets when properly located. The study is unique as it is one of its kind based on field data within the Middle East region and offers an insight into the potential concerns that may assist future fracturing operations within the region. The outcomes from this research validate the significance of NF orientation and its subsequent effects on the final HF geometry and network. Additionally, it further highlights the criticality of well placement and design strategies during hydraulic fracturing treatment design. Results describe how a minor modification with respect to the well placement can significantly affect hydraulic fracturing operations and subsequently the productivity and feasibility.

1. INTRODUCTION

Hydraulic fracturing is one of the most successful and proven reservoir-stimulation techniques, often used in low or moderate naturally producing wells. In addition to enhanced permeability, fracturing provides numerous benefits including sand production control and connectivity of layered and laminated formation by vertical penetration, and in gas wells, a significant reduction of the dominant turbulence effects on well performance in moderate to high permeability reservoirs can be achieved.1

Hydraulic fracturing is most common within unconventional resources. The definition for unconventional resources has evolved over time and is expected to continue evolving as new hydrocarbon resources are discovered. A comprehensive definition of unconventional oil and gas is the produced or extracted hydrocarbons using techniques other than the conventional methods for extraction.2 These resources include tight oil, shale oil, oil sands, shale gas, tight gas, gas hydrates, and coalbed methane. Today, unlocking these formations relies on the technological breakthrough represented by creating induced artificial pathways combined with drilling horizontal wells to improve the pre-existing natural fracture (NF) conductivity and achieve economical production rates.3

Unconventional and tight reservoirs have several particularly challenging characteristics, which include ultra-low reservoir permeability in the range of micro to nano-darcy, low porosity, poor connectivity, non-Darcy flow, high total organic content, and desorption behavior of the rock surface, as well as requirements for special production operations outside the conventional methods. All of these physical properties make hydraulic fracturing practice a challenging task. In order to
efficiently and economically recover gas from such reservoirs, hydraulic fracturing initiation and propagation in the heterogeneous fractured porous media under such complex circumstances should be mastered because of the heterogeneities present in these reservoirs. It is imperative to understand the fundamental difference between induced hydraulic fractures (HF) and NFs along with their impact. NFs are often regarded as areally extensive stress features generated by considerable subterranean rock movements such as uplifts, faults, and basement slumps over geologic time. In comparison, it is reported that hydraulic fracturing is an artificially induced alteration, which is minor with respect to the total drainage area for a given well. However, this is significant enough to activate or expand NFs that are commonly present in tight formations. This results in the creation of central pathways which allows for enhanced flow through these tight formations renowned for their extremely low permeability. The exploitation of these resources would not be feasible when produced through conventional approaches. The literature further supports this by stating that hydraulic fracturing operations are often required for up to 90% of oil and gas wells in North America.

The efficiency of fracturing operations is strongly influenced by the pre-existence and interaction with NFs, leading to more sophisticated fracture geometries. The creation of an illustrative model to mimic hydraulic fracturing in a naturally fractured reservoir is a demanding task as the involved coupled-physics processes occur on altered levels of the spatial scale. A representative model must provide an accurate demonstration of the interaction contained while maintaining the cost of computational power within bounds. Finally, designing controllable fracture treatment parameters is the key to the success of a hydraulic fracturing job. Hence, the major objectives for this research are:

1. Investigate the mechanism of HF propagation in the presence of NFs.
2. Perform analytical modeling to examine the significance of defined treatment parameters on fracture propagation behavior.
3. Conduct a parametric study using a commercial simulator that investigates the response of the changes in fracture treatment parameters in terms of HF interactions.

1.1. Modeling Techniques. As hydraulic fracturing operations and applications have significantly increased over the past few decades, the theories around fracture propagation evolved as well owing to better understanding of the in situ mechanisms. The fundamental two-dimensional (2D) models that were proposed involved various simplistic assumptions which allowed for basic simplistic calculation of fracture geometry with respect to the injected volume. However, fracture height was a major constraint in these models, which led to unrealistic results in zones with small closure stress contrast. For instance, numerous key publications between the late 1950s and the early 1970s established HF modeling approach foundation by making different assumptions regarding the significance of different physical aspects. Carter abandoned both the effects of solid mechanics and fluid viscosity and focused on leakoff. Khristianovich and Zheltov applied simplifying assumptions related to fluid flow and concentrated on fracture mechanics. Perkins and Kern made an assumption that fracture mechanics is fairly insignificant and focused more on fluid flow. This model was developed to estimate fracture geometry, mainly fracture width, for an identified flow rate and length, but it did not attempt to fulfill the volume balance. Carter presented a model that satisfies volume balance by assuming a constant, uniform fracture width. In the late 1970s, this model was utilized to determine volume balance. This approach was made obsolete by extensions established by Geertsma and de Klerk and Nordgren, respectively. These two fundamental models, commonly acknowledged as the KGD and PKN models after their respective developers were the first to take into account both solid mechanics and volume balance.

Over time, with advancements in computational resources, radial models coupled with advanced fracture geometry, pressure growth, and fracture diagnostics were developed. Pseudo-3D (P3D), power-law, gridded/parameterized/lumped-3D, and meshed/complex/coupled fracture models are a few notable major advancements over time.

For instance, P3D is a model typically used for horizontal or vertical wells by incorporating a planar fracture model with a single initiation point. It accounts for the fracture height and fracture pressure. In addition, some of these models also incorporate proppant parameters. This would result in more representative results as compared to the previously mentioned zones with small closure stress contract. Even so, most importantly in tight and unconventional play development perspectives, they still lack the representation of formation heterogeneities such as NFs, which are of particular interest in this research.

It is a well-known fact that the natural fracture network (NFN) contributes significantly to well productivity in shale and tight reservoirs. In the industry, it is widely accepted that the contribution of the induced HF is through the activation of the existing network of NFs. To recapitulate, NFs are often regarded as areally extensive stress features generated by considerable subterranean rock movements such as uplifts, faults, and basement slumps over geologic time. A collection of these NFs creates a NFN. Typically, tight formations consist of many NFs whose number, density, orientation, and mechanical properties vary widely in different formations. When the fracturing operation is performed in unconventional reservoirs containing NFs, the interaction of the HFs and the NFN may produce a complex fracture network that can further enhance the production and maximize it. Consequently, NFs can improve or lower production. Depending on the degree of the presence of NFs, a reservoir could become very compartmentalized and drain less area than anticipated. Therefore, it is crucial to identify the presence, type, and density of NFs in the reservoir.

Studies and recent advancements in models allowed to better understand the underlying mechanisms of HF propagation in the presence of NFs. For instance, investigations by Gu and Weng have shown that an induced HF gets arrested or terminated, when a propagating HF does not cross into a pre-existing NF. Fu et al. further report the arrestment of HFs in the presence of pre-existing cemented NFs and lack of crossing. This led to indications on how a pre-existing NF boundary with less unbonding will always result in the arrestment of HFs. This was further expanded and supported by the observations of Damjanac et al., Wang et al., and Fatahi et al. with respect to the approach angles.

Furthermore, Morris et al. and Huang et al. also investigated the effects of NF and closure stress interactions with respect to HF propagations. It was reported that the induced HF will be arrested at the NF boundary and not cross over the stress barrier mainly because of the height constraint of
the NFs within these zones. The literature further shows the implications of multiple HFs and the associated stress changes near the wellbore region. It is widely reported that multiple fractures that are close to each other significantly influence the formation stress. There is an accompanying increase with respect to the minimum horizontal stress near the wellbore region (stress shadowing). As a result, this increases the net pressure along with a potential stress-reversal, resulting in a longitudinal fracture near the wellbore region, especially in small-stress contrast zones. Even so, the HFs away from the region are less influenced and readjust themselves as their impact on distant stresses are minimal. Such directional changes usually introduce challenges with respect to tortuosity and screen out. Very few simulators are capable of handling such anisotropy and this is a major limitation in some commercial simulators as well. It is also to be noted that well performance depends on the size and efficiency of the interconnected fractures, as influenced by multistage hydraulic fracturing. A complex, interconnected NFN can considerably increase the size of simulated reservoir volume, providing additional surface contact area and enhancing the overall system permeability.

A discrete fracture network (DFN) model is another approach used to investigate fracture modeling and naturally fractured reservoirs. It provides individual fracture interconnection with relative varying length, orientation, relative spacing, intersection styles, and flow properties. The generic model may include fractures, bedding surfaces, and other porous reservoir bodies. DFN models are stochastic models of fracture structural design that include statistical scaling rules derived from analysis of fracture width, length, height, orientation, and spacing. A DFN contains groups of planes that are representative of fractures. Fractures of similar type that are generated simultaneously are grouped into a fracture set. Every fracture network contains fractures that have a minimum of at least one fracture set. The simplest fracture sets are characterized deterministically as a group of previously defined fractures, either as a result of interpretation because of extraction of a fault plane from a seismic cube, or through a previously defined fracture.

As stated earlier, hydrocarbon production from unconventional resources (extremely low permeability formations) is only feasible and economical through artificially induced stimulation or hydraulic fracturing, which results in the creation of a complex fracture network. This complex network is constructed by the interaction of HFs with the pre-existing formation heterogeneities including rock fabric, texture, planes of weakness, or NFs. An unconventional fracture model (UFM) is a model that presents a complex fracture network. It is based on similar assumptions and governing equations as in the conventional P3D fracture model, but it is capable of simulating a complex fracture network. It simulates fracture propagation, rock deformation, stress shadow, and fluid and proppant flow in the complex network of the fractures. The model finds a solution for the fully coupled problem of fluid flow in the fracture network and the elastic deformation of the fractures.

Compared to the P3D model, instead of solving the problem for a single planar fracture, UFM solves the equations for the complex fracture network. A three-layer proppant transport model, containing proppant bank at the bottom, a slurry layer in the middle, and clean fluid at the top, is assumed to simulate proppant transport in the complex network. The solution of transport equations is found for each component of the proppant and fluids pumped. Another major difference between UFM and the P3D model is being capable to simulate the interaction of HFs with pre-existing NFs, that is, determining whether HFs propagate through or are arrested by NFs when they intersect and consequently propagate along the NFs. A brief overview of the discerning and differentiating features among these models is provided in Table 1.

### Table 1. Brief Comparison—P3D vs UFM

| parameters                                | P3D | UFM |
|-------------------------------------------|-----|-----|
| formation properties                      | √   | √   |
| poro-thermoelastic coupling               | √   | √   |
| mechanical properties                     | √   | √   |
| propagation behavior and mechanics—simple | √   | √   |
| fluid-loss considerations                 | √   | √   |
| stress properties—simple                  | √   | √   |
| nonvertical/horizontal wells              |     |     |
| propagation behavior and mechanics—advanced |     |     |
| stress properties—advanced                |     |     |
| near-wellbore interaction                |     |     |
| formation interface properties and analysis |     |     |
| natural fracture interaction, distribution, orientation, and properties |     |     |

HF branching at the intersection with the NF provides a rise to the development of a nonplanar, complex fracture configuration. A crossing model that is derived from the Renshaw and Pollard and nonorthogonal extended criterion by Gu and Weng, which was developed and validated against the experimental data, is also incorporated into the model. In addition to the HF/NF interactions, the UFM also takes into consideration the interaction between neighboring HFs by incorporating the “stress shadow” effect on each fracture by the neighboring fractures. Hence, because of all these comparative advantages, UFM was the preferred model for this investigation.

### 1.2. Available Data.

The impact of many NF configurations on the induced HF network is examined through a parametric study using the UFM complex fracture model. The results demonstrate how the NF orientation, density, and length may impact the resulting fracture network.

The parametric study presented here uses a base case of a naturally fractured tight gas formation in the Middle East. The geomechanical and petrophysical data description is presented in Table 2. A single cluster with four perforations will result in four transverse HFs 80 ft apart.

### Table 2. Input Reservoir Data Used in the Numerical Model

| input data                      | value         |
|---------------------------------|---------------|
| formation depth (ft)            | 6850          |
| reservoir temperature (°F)      | 358           |
| porosity (%)                    | 3.6           |
| absolute permeability (mD)      | 0.1           |
| water saturation (%)            | 55.1          |
| Young’s modulus (psi)           | $6.69 \times 10^6$ |
| Poisson’s ratio                 | 0.19          |
| reservoir pressure (psi)        | 10,849        |
| minimum horizontal stress (psi) | 12,763        |
| maximum horizontal stress (psi) | 14,765        |
| fracture gradient (psi/ft)      | 0.82          |
Once the input data were integrated to the constructed model, it was successfully validated. This involved verifying and comparing the behavior with the field data. The values of the input parameters were cross-referenced with the field data provided, and they were within reasonable limits.

Proppant definition and properties were also a primary input to define stimulation cases along with fracture propagation behavior analysis. Proppants considered for this study were selected after a comprehensive study and from a wide available database including official FracCADE proppant database and Mangrove user proppant database. In this stimulation job, −80 + 100 mesh sand, Badger sand 40/70, and Bradley gravel pack 20/40 are used for the base case. Their critical proppant properties are shown in Table 3.

### Table 3. Proppant Properties

| Property               | −80 + 100 mesh sand | Badger sand 40/70 | Bradley gravel pack 20/40 |
|------------------------|---------------------|-------------------|--------------------------|
| Mesh size (μm)         | 80/100              | 40/70             | 20/40                    |
| Mean diameter (μm)     | 0.16                | 0.29              | 0.62                     |
| Specific gravity       | 2.64                | 2.64              | 2.65                     |
| Bulk density (kg/m³)   | 1602                | 1670              | 1648                     |
| Propped fracture       | 4.88                | 4.88              | 4.88                     |
| Concentration (kg/m²)  | 10³                  | 10³               | 10³                       |
| Young’s modulus (kPa)  | 20.7 × 10³          | 20.7 × 10³        | 20.7 × 10³               |
| Stress on proppant (kPa)| 21.3 × 10³          | 21.3 × 10³        | 21.3 × 10³               |
| Pack porosity (%)      | 35                  | 35                | 35                       |

### 1.3. Model Limitations and Assumptions

The construction of the preliminary model began with the construction of the lateral well based on field data. For the most simplistic case, there were no NFs introduced within the system. This provided an opportunity to evaluate the models present within commercial simulators to evaluate the fracture propagation behavior.

This comparison was based on the same reservoir conditions and treatment parameters while only varying the fracture geometry model. Based on the inputs incorporated, the most realistic model with respect to the field data was found to be the UFM model. Based on the simulation results, it is noted that the P3D model gave the largest propped half-length and the propped width, resulting in significantly higher conductivity. The planar 3D and the wiremesh model had smaller average fracture width as they have multiple assumptions that may be unrealistic in the field conditions. For example, the planar 3D assumes a perfectly planar fracture while only considering the propagation of fractures in the direction of maximum horizontal stress. This has been further analyzed and illustrated in detail by Suboyin et al. The integrated workflow within the simulator also introduces new HF models. These models incorporate the 3D varying geologic model and NF definition to calculate how a HF will propagate fluid and proppant into the reservoir. This HF understanding is then translated into a reservoir engineering focused model to estimate the effect on production.

Before analyzing simulation outcomes and drawing conclusions based on them, it is vital to discuss the underlying assumptions within the constructed model. The key assumptions and constraints are listed below.

1. Constrained fracture height: as zones are defined within the model, the fracture propagation is limited to the defined zones. This assumption assists in analyzing the fracture propagation behavior as fracture height containment is a critical design factor in most reservoirs.
2. Temperature effect: as fluids are injected to the targeted formation, their behavior as temperature changes are limited within the simulator. This may lead to some variations with respect to results based on reservoir conditions.
3. NFN: a 2D fracture network was introduced to artificially characterize the reservoir conditions. However, this is not realistic enough to mimic the presence of NFs in field.
4. Shut in period: shut-in period was not considered, while considering production forecast.
5. Permeability change: when injecting multiple proppant, the change in proppant pack permeability cannot be accounted for within the simulation.

### 2. RESULTS AND DISCUSSION

#### 2.1. NF Orientation

Patterns of HF propagation in naturally fractured reservoirs could be affected by several factors including rock properties, pumping fluid properties, fluid pumping schedule, stress anisotropy, stress shadow caused by the interaction of different propagation streams of HFs, and the interaction of HFs with pre-existing NFs in the formation. The results demonstrate the significant impact of NF orientation and their corresponding effects on the resulting fracture network. The interaction between the induced HFs and the pre-existing NFs has a great impact on the final complex network footprint. It has been reported that the larger the intersection angle between
hydraulic and NFs, a more complex network was observed. This is a result of the greater deviation of the HFs from their original pathway and intersecting further NFs. A stimulation case was conducted that does not incorporate the presence of any NFs and simulates the propagation behavior of the HFs without any surrounding heterogeneities. The resulting fracture properties and their representation are shown in Figure 1 and Table 4, respectively. This case is idealistic as the propagation of the HFs is not interrupted by any heterogeneities or discontinuities in the formation such as NFs. Consequently, the fractures have greater extension/penetration in the direction that it grows.

2.1.1. Base Case 1—NF Orientation. This case represents a field data acquired from a tight sandstone reservoir in Abu Dhabi with some incorporated data from the literature. The used petrophysical and geomechanical field data can be found in Table 1. The well trajectory design includes a lateral well section extending up to 2000 ft. The number of designed pumping stages along the horizontal wellbore section is around 10 stages evenly spaced, all of them having similar pumping schedules. Each cluster includes four perforations, which produces four induced transverse fractures. A single cluster with a single pumping stage is used to examine the effects of the presence of NFs. The overall design treatment for this fracturing job consumed in total 1568 bbl of fracturing fluid, 568 lb of proppant mass, 1568 bbl of slurry volume, and 16.62 min of pumping time. This base case incorporates a NF set that has an orientation of 0° with respect to the lateral section. The resulting fracture properties and their representation are shown in Figure 2 and Table 5, respectively. In these results, the NF orientation is isolated to be further examined regardless of how these orientations are generated.

2.1.2. Variations from Base Case. To investigate the effects of pre-existing NF orientation and its correlated effects in the studied tight gas formation in terms of productivity enhancement and the propagation behavior of the induced HFs, 13 different sets of NF orientations are separately examined by running multiple simulations and critical parameters are analyzed subsequently. All of the introduced NF sets are presented in Table 6. It is to be noted that the orientation and the approach angles for the constructed NF sets are with respect to the wellbore.

Table 4. No NF Case Results

| average fracture conductivity (mD·ft) | average fracture width (in.) | average fracture height (ft) | average fracture length (ft) |
|--------------------------------------|------------------------------|-----------------------------|-----------------------------|
| 5.28                                 | 0.0016                       | 22                          | 624                         |

Table 5. Base Case Results

| average fracture conductivity (mD·ft) | average fracture width (in.) | average fracture height (ft) | average fracture length (ft) |
|--------------------------------------|------------------------------|-----------------------------|-----------------------------|
| 4.43                                 | 0.00108                      | 19                          | 546                         |

Table 6. Simulation Results

| set # | NF orientation (deg) | average fracture conductivity (mD·ft) | average fracture width (in.) | average fracture height (ft) | average fracture length (ft) |
|-------|----------------------|---------------------------------------|------------------------------|-----------------------------|-----------------------------|
| base  | 0                    | 4.43                                  | 0.00108                      | 19                          | 546                         |
| 1     | 15                   | 8.71                                  | 0.00217                      | 11                          | 549                         |
| 2     | 30                   | 55.18                                 | 0.00541                      | 6                           | 395                         |
| 3     | 45                   | 7.05                                  | 0.00207                      | 11                          | 462                         |
| 4     | 60                   | 6.66                                  | 0.00187                      | 16                          | 580                         |
| 5     | 75                   | 8.53                                  | 0.00177                      | 17                          | 587                         |
| 6     | 90                   | 4.68                                  | 0.00128                      | 24                          | 650                         |
| 7     | 105                  | 6.18                                  | 0.00157                      | 18                          | 614                         |
| 8     | 120                  | 8.78                                  | 0.00167                      | 14                          | 541                         |
| 9     | 135                  | 6.21                                  | 0.00148                      | 16                          | 490                         |
| 10    | 150                  | 15.44                                 | 0.00256                      | 9                           | 503                         |
| 11    | 165                  | 7.90                                  | 0.00167                      | 16                          | 506                         |
| 12    | 180                  | 9.15                                  | 0.00207                      | 12                          | 469                         |

Figure 2. Base case representation.
parameters such as the precise placement/location of the fracture and associated inherent properties may slightly differ for each constructed set. For that reason, the analysis of symmetrical NF orientations was not addressed in this study.

2.1.4. Analysis of Results. 2.1.4.1. Average Fracture Conductivity. A successful enhancement in well productivity from an induced fracture must have permeability orders of magnitude greater than the original reservoir matrix permeability. When pumping has stopped and the hydraulic fluid pressure has dropped below that required to keep the fracture open, the fracture may close, and in doing so, substantially eliminates the desired conductive pathway to the wellbore. Proppants, or propping agents, are placed in the fracture to maintain the flow path after the treating pressure is relieved. Ideally, the proppant will provide flow conductivity large enough to minimize pressure losses in the fracture during production. The fracture conductivity defines the conductive path provided by the proppant material to enhance deliverability and provide economic benefit when the well is placed on production. Traditionally, this is measured as the product of proppant permeability and propped fracture width \((k_p \omega)\) and is reported in mD-ft and is a key design parameter.\(^{11}\)

The average fracture conductivity is the first crucial parameter to begin with because it defines the productivity of the well and the related economics which will define the success of the stimulation process. Figure 4 illustrates the average conductivity for all four induced HFs for each NF orientation set. As demonstrated in Figure 4, the presence of NFs mostly contributes to the enhancement in the average fracture conductivity, which in its role enhances the production performance. In general, the orientation of NFs can have either a beneficial or a harmful effect on the resulting average conductivity. In this study, all the alternative cases yielded an increase in the average fracture conductivity which is variant to...
some degree as the interaction patterns with NFs are different. Only one fracture orientation case showed a slight increase compared to the base case which is 90° that is presented in Figure 5. For this set, the introduced NFs are parallel to the induced fractures and the resulting fracture surface area is greater than the base case, resulting in less propped portions of the total surface area as the operational treatment parameters are fixed. In addition, as noticed in the figure, there is an anomaly case that reflects a dramatic increase compared to the base case. This is mainly caused by the interactions with NFs in a short distance after HFs have started propagating. This specific fracture orientation will be discussed in detail in the following section that includes all cases and justification for their resulting behavior.

2.1.4.2. Average Propped Fracture Width. A major design goal is fracture conductivity \( k_f \), which consists of proppant pack permeability and propped fracture width.\(^9\) Propped fracture width is controlled by the executed treatment design. The changes of the resulting propped fracture width as the orientation of the introduced NF set are highlighted in Figure 6.

As shown above, a notable increase in the fracture aperture is observed compared to the base case in all sets. The additional produced average fracture width varies as the NFs are introduced and oriented. Overall, the resulted fracture aperture for all sets ranges from 0.00108 to 0.00256 in., excluding the outlier case of 30°. This range of fracture width change is considered to be significant which has more influence on fracture conductivity and other fracture geometry elements. This increase contributes to the enhancement in fracture conductivity as it is tightly related to the propped fracture width. The results observed above support the outcomes and have similar justifications as the Average Fracture Conductivity section.

2.1.4.3. Average Propped Fracture Length. Fracture length is measured as the largest distance between the well and a point on the fracture tip. The generated fracture length is the fracture length propagated during the fracture treatment, while the propped fracture length is the length held open by the proppant after the fracture closes which contributes to hydrocarbon production after a fracture treatment. A reliable estimation of the fracture length is essential to consider design changes in subsequent fracture treatments in order to further optimize the performance of hydraulically fractured wells particularly in low permeability reservoirs. Increasing the effective structure length usually means increasing production.\(^32\) As the fractures propagate in naturally fractured formations, they show a complex propagation behavior that is dependent on the NF properties. Variations in predefined NF orientations and their subsequent effects on the fracture length are demonstrated in Figure 7.

Varying NF orientation results in changes of the final HF extension. As shown in the figure, the average propped fracture length varies as the NF orientation changes as it falls in range from 462 to 650 ft, excluding the 30° case as it is considered as an outlier given by its overall propagation behavior. The changes in the fracture length are within reasonable limits and it have less influence on the fracturing operation outcomes. This comes as a result of introducing 2D NF sets and the complex propagation that it induces on the created HFs. More interactions between the HFs and the pre-existing NFs result in a complex fracture network where HFs contribute to fracture growth in other fracture geometry parameters other than the length. In addition, as the interaction pattern changes, the subsequent leakoff volumes and total and propped fracture surface area vary,

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**Figure 5.** 90° NF orientation set.

**Figure 6.** Average propped fracture width results.

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respectively. In terms of fracture length results, the 90° orientation case is an outlier as it shows a significant increase in the fracture length that reached above 100 ft. In this particular case, the HFs and the NFs are parallel, so all possible interactions lead to further propagating the fracture on its original direction.

2.1.4.4. Average Propped Fracture Height. The restriction of fracture height growth is important in low- to moderate-permeability formations, where relatively long fractures are required for effective stimulation. The fracture height growth is contained by a barrier below and is restricted by an upper barrier of shale zones. During the simulations, the fracture height must be assured to be contained in the targeted sandstone formation because the perforations are located in the center of the formation and the fracture height did not exceed the formation thickness. The changes in the fracture height, excluding the 30° case, are reported in range of 9−24 ft, and they have minor effect on the final fracture geometry. In the demonstrated cases above, over 90% of the introduced NF orientations resulted in a reduction of the fracture height. This comes as a result of having a significant growth in either or both average fracture width and average fracture length. The only case that showed a slight increase in terms of fracture height is the set introduced at 90°. This case, as previously discussed, showed a reduction in average fracture width which reflected on the growth of either or both average fracture height and average fracture length.

2.1.5. Cases Analysis—NF Orientation. After examining the effects of NF orientation on crucial hydraulic fracturing geometrical parameters and its ability to conduct gas flow to the wellbore, a combined overview of all of the outcomes will define which cases are the most effective for this applied treatment. As depicted in Figure 3, these cases are categorized depending on the relative similarities in terms of the simulation outcomes and in comparison with the base case.

2.1.5.1. 15° Case. As illustrated in Figure 3, the presence of this NF orientation results in favorable impacts in terms of nearly doubling the average fracture conductivity and average fracture width compared to the base case and achieving a few additional feet in terms of fracture length. These overall enhancements have consequently considerably reduced the fracture height.

2.1.5.2. 30° Case. As illustrated in Figure 3, the interaction in this case results in an outlier that shows a dramatic increase in both fracture conductivity and average width. Conversely, there is a considerable decrease in fracture height and extension that reaches as high as 150 ft from the base case. These events come as a result of the three out of the four induced fractures that interacted with the NF after a short distance from their creation, as depicted in Figure 3. Consequently, the fractures extended through these NFs.
2.1.5.3. 45 and 180° Cases. As illustrated in Figure 3, the interaction pattern in these two cases has elevated fracture width and accordingly fracture conductivity to some reasonable extent compared to the 0° case. Conversely, the propped fracture geometry in terms of fracture length and height has experienced a serious reduction. This geometry results as the interaction with NFs takes place after a short notice of HF propagation and as multiple HFs interact with a particular NF.

2.1.5.4. 60, 75, and 105° Cases. As illustrated in Figure 3, these cases show a relatively similar behavior where the inspected outcomes are overall comparable. Generally, a favorable impact of these interactions is observed because there is an increase in fracture conductivity, fracture width, and fracture length. In terms of fracture height, they show a fair stability compared to the base case.

2.1.5.5. 90° Case. As illustrated in Figure 3, the NFs are introduced parallel to the induced fractures within this case. This is the only case that shows considerable growth in terms of fracture height, length and comparable results in terms of fracture conductivity and width. This NF orientation allows HF to extend more in that direction in case there is an interaction, which maintains the fracture surface area and subsequently the total propped fracture surface area.

2.1.5.6. 120, 135, and 165° Cases. These cases express an improvement with regard to fracture conductivity and average width, as seen in Figure 3. It also maintains substantial fracture length and height with minor reductions compared to the 0° case. The sophisticated interaction criteria with multiple NFs as they extend through the formation is the dominant factor that resulted in such a geometry.

2.1.5.7. 150° Case. As illustrated in Figure 3, the influence of this NF set on the overall fracture geometry is demonstrated by the notable increase in both fracture conductivity and average width that reached at least triple and double the base case, respectively. In contrast, it exhibits a reduction in fracture length and height approximated by 8 and 51% difference in comparison to the base case, respectively.

2.1.5.8. Further Analysis. After running simulations for all of the predefined sets, three cases are further discussed and analyzed to better understand their behavior. From Figure 3, cases 30 and 90° exhibit signature trend, whereas 150° case illustrates a common overall behavior noticed in the other sets. In terms of average fracture conductivity, the simulated values are significantly different as compared to the base case. For instance, the dramatic increase in the 30° case comes as a result of the interaction of the first three induced fractures with either nearby NFs after a short distance of their creation or around the wellbore region. So, all these three fractures contribute to the growth with respect to fracture width which in-turn significantly elevated the conductivity. With respect to the 90° case, the HFs are interacting with the parallel NFs. The propagation behavior in this case, as shown earlier, is considered to be idealistic because the NF orientation is parallel to the propagation direction and there is no complex fracture network formed. This is rare to achieve as naturally fractured reservoirs are often highly heterogeneous in nature and randomly distributed. The presence of such NF orientation provides more extension to the growing HFs in terms of fracture geometry as they extend more through these parallel NFs. However, for the 150° case, the elevation is observed from a combined effect because of the presence of NFs near the perforation levels and the development of complex fracture network as HFs interact with NFs, which results in fracture extension. When analyzing the average fracture width, the simulation results further support the fracture conductivity observations.

With regard to the average propped fracture length, all cases indicate a decline as compared to the base case. This comes as a result of introducing the NFNs and their effects on the created HFs along with incorporating the effect of leakoff during the fracture process. It is important to note that the 90° case is an outlier because of observations reported earlier and hence it shows a dramatic increase in the fracture length. All HF interactions with this set lead to further propagating the fractures as they are parallel to each other. Furthermore, fracture height analysis for the 30 and 150° cases showed a reduction compared to the base case. This is due to the fact that the volumetric input remains the same, and for each case, there is a significant growth in either or both fracture width and fracture length, resulting in a lower fracture height. The 90° orientation set is the only case that showed a slight increase and an outlier because of the idealistic propagation behavior.

In summary, it is agreed that the most idealistic case among the three presented cases is considered to be the 150° NF orientation which represents a common overall behavior noticed in the other introduced NF orientations. It provided conductivity enhancement, and it developed a complex fracture network besides the well-developed HFs.

After briefly discussing all cases and explaining their behavior, it must be noted that a balanced effect is required to achieve a realistic stimulation result when considering NF orientation as a variable parameter. This equilibrium is accomplished by maintaining favorable results in terms of fracture conductivity and propped fracture geometry elements. So, for cases that show unfavorable outcomes that represent either/both reduction in fracture conductivity and similar fracture propagation behavior to the base case are totally unacceptable. This also applies for the case showing a tremendous elevation in fracture conductivity and inversely with regard to the resulted fracture geometry. The only cases that can be described as successful are the ones achieving an improvement in fracture conductivity and in parallel shows reasonable fracture propagation in terms of fracture width and extension through the formation to achieve maximum reservoir exposure.

2.2. Well Placement. In low permeability gas reservoirs, NFs are often the principal conduit for gas flow in the formation and can significantly influence the well performance and productivity. Moreover, in oil reservoirs, oil production volume is greatly dependent on well location and reservoir geological properties. Understanding the interaction between the induced HFs and the pre-existing NFNs is the key in the successful development and exploitation of these potential resources. Planning an effective field development approach involves estimating the best location to place the well. Well placement plays a vital role in tight gas reservoir exploitation. The proper analysis of such development plans can be considerably complicated in the presence of complex geological heterogeneities, particularly when inducing HFs as they interact with the pre-existing NFNs and their consequences on well drainage volumes.

To attain the maximum benefit economically, the optimization of well placement is necessary to determine the best locations for placing wells in a certain reservoir. The most commonly used method for well placement optimization problems is reservoir flow simulation. Optimistic well positions are determined by maximizing the output variable of interest to
the assessment like the cumulative hydrocarbon production or net present value produced by a reservoir flow simulator. The problem of well placement optimization is assessed by running multiple simulations with all given well positions and finally analyze the results and proceed to the decision-making phase based on the acquired simulator outputs.  

2.2.1. Base Case 2—Well Placement. The base case includes a complex NFN, resulting from combining all data sets examined in the Natural Fracture Orientation section. This gives a more realistic study for such naturally fractured formations, and the outcomes show a relative match with the acquired field data. This case includes the original well placement location considered in the simulation model where the well is placed in the center of the formation at 6850 ft. A single cluster with a single pumping stage is used to examine the effects of wellbore placement. The complex NF set and the resulted HF network are illustrated in Figures 9 and 10, respectively. The critical results obtained from this simulation is shown in Table 7.

2.2.2. Variations from Base Case. Four other cases are then developed to examine the effects of changing wellbore location to the outcomes of hydraulic fracturing operation. This is carried out by shifting the well vertically from the original location as a consequence of changing the inclination angle from the kickoff point. The details of the well trajectories are shown in Table 8 and Figure 11, where case 1 represents the base case and cases 2, 3, 4, and 5 represent moving the well vertically by −83, 83, −41,
and 41 ft from the original well location, respectively. All other treatment parameters and NFN properties are fixed.

2.2.3. Simulation Results. After making the required adjustments and modifications to the simulation model, the following data and illustrations in Table 9 and Figure 12 are obtained.

2.2.4. Result Analysis and Discussion. The discussion is based on analyzing the simulation results in terms of average fracture conductivity and average propped fracture geometry. Based on the results of the simulated cases, there are significant effects on the fracture propagation behavior primarily because of changes in the in situ stress along with the NF distribution around the region. As a result, this greatly influences other dominant parameters such as stress interaction, NF and HF propagation/geometry, approach angles, wellbore, fracture orientation, and so forth.

2.2.4.1. Average Fracture Conductivity. The composite effect of a complex NFN and wellbore placement highly influence the ability of the HF network to conduct the flow to wellbore. The effect of wellbore placement represented by the predefined cases on average fracture conductivity is shown in Figure 13. It emphasizes the considerably large effects of changing wellbore location by a small degree of inclination from its original planned trajectory. The first two developed alternative cases show a much higher average fracture conductivity, which is at least 15 times greater than the base case. This dramatic increase comes as a result of the deference of wellbore elevation at which it penetrates the formation and yields different interaction criteria with the fixed NFN. In cases 2 and 3, wider and shorter fractures are observed which elevated the average fracture conductivity to be as high as 315 and 75 mD·ft, respectively. This outcome is caused by the interaction criteria with the nearby NFs. As illustrated in Figure 12, the interactions in these two scenarios take place either in a short distance after HFs starts propagating or directly at the perforation levels of the HFs. This behavior allows to dilate the nearby created fracture network and limit its extension into the reservoir. Conversely, cases 4 and 5 provide a relative enhancement in fracture conductivity compared to the first case. This is justified by the comparable interaction criteria between the cases where the HFs had a chance to extend to some length in the formation and along that it contributed to the creation of a more complex fracture network by interacting with NFs and propagating through them by not necessary dilating them.

2.2.4.2. Average Propped Fracture Width. Figure 14 shows the resulting average fracture width. Generally, the fracture aperture for all cases ranges from 0.00187 to 0.00650 in., excluding case 2 as it is an outlier. This range of fracture width change is considered to be significant which highly influences fracture conductivity, fracture length, and height. Overall, there is a significant increase in the average fracture width in cases 2 and 3 caused by the dilation of the activated nearby NFs, which most likely will yield an enhancement in terms of production performance. This growth in fracture width will affect the rest of the fracture geometry including the fracture length and height.

| Table 7. Base Case Results |
|-----------------------------|
| average fracture conductivity (mD·ft) | average fracture width (in.) | average fracture height (ft) | average fracture length (ft) |
| 8.83 | 0.00187 | 10.73 | 374 |

| Table 8. Well Trajectory Details |
|----------------------------------|
| case # | MD (ft) | inclination (deg) | TVD (ft) | ΔMD (ft) | ΔTVD (ft) | Δinclination (deg) |
| 1 | 11,315 | 102.64 | 7370 | | | |
| 2 | 11,315 | 103.64 | 7287 | 0 | −83 | 1 |
| 3 | 11,315 | 101.64 | 7453 | 0 | 83 | −1 |
| 4 | 11,315 | 103.14 | 7329 | 0 | −41 | 0.5 |
| 5 | 11,315 | 102.14 | 7411 | 0 | 41 | −0.5 |

Figure 10. HF interactions with the complex NF set.
On the other hand, moderately similar results are obtained for the last two cases to the base case where the overall interaction is driven by the extension of HFs and the created complex network with NFs.

### 2.2.4.3. Average Propped Fracture Length.

Figure 15 illustrates the behavior of fracture length changes as wellbore placement changes. The fracture length varies as the wellbore placement changes and it falls in range from 192 to 390 ft, excluding the second case as it shows a signature propagation behavior. The changes in the fracture length are within reasonable limits and it have less influence on the fracturing operation outcomes. In cases 2 and 3, a considerable decrease in the fracture length is noticed as a consequence of increasing fracture width where the injected fluids contributed more in the growth of fracture width rather than fracture length and height. In contrast, cases 4 and 5 showed a similar behavior to the base case. The injected fluid in these cases mainly supported HF propagation in the formation and the creation of a more complex network as they were interacting with the pre-existing NFs. This lead to increasing fracture length and subsequently the surface area of the formed complex fracture network.

### 2.2.4.4. Average Propped Fracture Height.

Figure 16 shows average fracture height with respect to the presented cases that denote multiple wellbore placements. The changes in fracture height, excluding the second case, fall in range of 9–11 ft which is a small window of change so they have the least effects on the final fracture geometry. Case 2 shows a significant decrease in fracture height as a result of the growth in other fracture geometry parameters. It has the highest average fracture width which consequently results in lower fracture length and height. For the rest of the cases, the difference in the resulted fracture heights compared to the base case can be described as nearly steady. This is observed from the differences in each case with respect to the relative growth/decline in fracture width and length which at the end resulted in relatively similar propagation behavior in terms of fracture height.

### 2.2.5. Cases Analysis

#### 2.2.5.1. Case 1.

This is considered as the base case for wellbore placement. It includes a highly complex NFN which greatly influences the propagation of HFs and their ability to conduct fluid flow. Comparing this case with the homogeneous case presented earlier that does not encounter any planes of weaknesses, it shows an increase in fracture conductivity and average width accompanied with an excessive reduction of at least 50% in the other fracture geometry parameters. These effects come as consequences of the very complex reaction with NF set as HF propagates along the treatment.

#### 2.2.5.2. Cases 2 and 3.

These cases are generated by changing the inclination angle by ±1° from the kickoff point and fixing all

### Table 9. Simulation Results

| case # | average fracture conductivity (mD·ft) | fracture width (in.) | fracture height (ft) | fracture length (ft) |
|--------|--------------------------------------|----------------------|----------------------|----------------------|
| 1      | 8.83                                 | 0.0019               | 11                   | 374                  |
| 2      | 314.61                               | 0.0294               | 3                    | 188                  |
| 3      | 75.25                                | 0.0065               | 9                    | 192                  |
| 4      | 15.10                                | 0.00325              | 9                    | 390                  |
| 5      | 8.04                                 | 0.00187              | 11                   | 370                  |
the other parameters in the simulation model including the NF set. This results in an elevation change with respect to True Vertical Depth (TVD). Consequently, the wells are shifted upward and downward by 83 ft. When comparing the extension criteria of the HFs, an enormous improvement in both average fracture conductivity and width was found. These improvements inversely affected the growth in fracture height and length. Extending the analysis using additional simulation outcomes reported in Table 10, an additional increase in the total fracture volumes equal to 247 and 177 ft³ was observed respectively, which supports the reduction in the total leakoff volume in both cases. This reduction in leakoff contributed to the fracture growth which increased the final fracture volume. In addition, wider created fractures reduce the surface area relative to the
applied treatment volume, as indicated by the additional acquired data. As stated earlier, these treatment volumes contribute to the growth in fracture width other than fracture length and height as the interactions with NFs take place near or at the perforation levels. In addition, there is a wide difference in the propped fracture surface area which is related to constant proppant amount in the treatments while there is a variation in the total fracture surface area in each case. Proppant settlement and its consequences on both the propped fracture geometry and the flow within the fractures should also be taken into consideration. These overall influences are observed from well placement changes. As the position of the well changes, the types, complexity, and number of interactions with the NF changes.

Figure 14. Average propped fracture width results.

Figure 15. Average propped fracture length results.

Figure 16. Average propped fracture height results.
Table 10. Additional Simulation Results—Wellbore Placement

| case | fracture volume (ft³) | leakoff volume (ft³) | fracture surface area (ft²) | propped fracture surface area (ft²) |
|------|----------------------|---------------------|----------------------------|-----------------------------------|
| 1    | 8370                 | 459                 | 462,892                    | 36,168                            |
| 2    | 8617                 | 177                 | 152,695                    | 3,099                             |
| 3    | 8546                 | 247                 | 215,351                    | 12,390                            |
| 4    | 8440                 | 353                 | 387,720                    | 21,721                            |
| 5    | 8334                 | 459                 | 478,157                    | 36,886                            |

2.2.5.3. Cases 4 and 5. The generation of these two cases was accomplished by shifting the inclination angle by ±0.5° from the kickoff point. All other associated parameters are fixed in the simulation model including the complex NFN. This affects the well trajectory by changing the TVD. Accordingly, the wells are shifted upward and downward by 41 ft. After studying the propagation behavior of the discussed scenarios, it was found that they are acting similarly to the base case in all presented aspects of fluid flow conduction and propped fracture geometry. This statement is further supported by the presented data in Table 8. Minor differences in the total fracture volume was observed which is represented by a growth of 71 ft³ and a reduction of 35 ft³ for cases 4 and 5, respectively. These changes can be directly related to the total leakoff volumes. The reduction in leakoff contributed to fracture growth or the slight difference in leakoff resulted in a very similar fracture volume in comparison with the base case. Furthermore, when analyzing the total fracture surface area, it was determined that the reduction in case 4 was caused by the slight growth in width. Conversely, a similar stable level of magnitude of fracture surface area in the last case compared to the base case is a result of the similar behavior of fracture propagation, extension, and interaction with the NFNs. These high fracture surface area results can be linked to the extent that fracture lengths grow in these cases covering penetrating more reservoir volume and subsequently increasing the overall fracture surface area. It is also regarded to their ability to penetrate/interact with NFNs and propagate through them which enables covering additional fracture surface area. After adding proppant to the injected fluids, the variation in propped fracture surface area is analyzed. There is an insignificant difference in the propped fracture surface area in these two cases. Case 4 shows a lower magnitude of propped fracture surface area which can be related to fixed amount of added proppant and the previously mentioned increase in the total fracture volume. For case 5, it demonstrates a parallel outcome as the base case as it acts similarly on all comparison aspects.

The most optimistic case among the above is the fourth case. It delivers a realistic and effective balance between the accomplished fracture conductivity and the resulting fracture geometry that covers a considerable reservoir volume for the applied treatment design. Comparing the outcomes with the base case, there was an elevation in fracture conductivity enhancement, which is approximately twice the base case. From the fracture geometry perspective, the resulting geometry from the fourth case shows a remarkable elevation in fracture width and a better extension in the reservoir within the created complex fracture network compared to the other cases as a significant fracture height is maintained. This case will provide a sustainable production with time as all HF targets are well developed in terms of initiation and propagation compared to all the other cases.

3. CONCLUSIONS

In this study, simulation cases were constructed to investigate the influence of defined NFN set contrast on HF geometry and propagation behavior. This included data from a candidate Middle Eastern field. It is observed that the fracture sets introduced using a DFN have definite effects in terms of HF geometry and fracture conductivity. Multiple cases were created to analyze their behavior, and parametric sensitivity analysis was also conducted. In addition, the significance of wellbore placement was also examined. Simulations highlight how the overall productivity might be drastically affected even with a minor shift of 25 ft with respect to the placement. Coupled with hydraulic fracturing treatment design, this also influences the fracture ability to conduct fluid flow and the final extension behavior of the induced fractures in the presence of complex NFNs.

The following are key observations deduced from this study:

1. Based on the constructed simulation cases and for the given set of input data, the influence of fracture aperture was more dominant as compared to the fracture length. For the constructed field model, the fracture aperture had the potential to be improved by nearly 240% times as compared to 160% with respect to the fracture length.

2. Multiple simulation cases were constructed along with the introduction of NFN settings, which allowed to identify and quantify the key parameters within a traditional hydraulic fracturing design process.

3. A parametric study was conducted to investigate the response in fracture treatment parameters in terms of HF interactions along with wellbore placement. Results from the constructed sets demonstrate the dominance and criticality of NFN orientation and its subsequent influence on the final HF geometry and network. For the given model constructed with regional data, 150° NFN degree set was the most representative case in comparison with the other sets.

4. Changes in well placement design also indicated a significant effect to the overall outcome of the treatment design and subsequently to the productivity and economics of the stimulation operation. As highlighted, a minor difference in the well placement design significantly affects fracture propagation. One of the cases (case 4) showed a dramatic improvement as compared to the original fracture design parameters, while another case (case 2) showed a drastic decline in the overall productivity leading to unsustainable production. Hence, the variations resulting from well placement must be studied extensively which can greatly affect the overall economics.

4. RECOMMENDATIONS

Based on the presented results and observations, there was substantial potential to improve the original fracturing design and targeted field productivity where the fracturing operation was executed. This includes addressing a few constraints/limitations within the simulator as well.

1. This includes enhancing the number of transverse HF clusters, orientation, spacing, and additional heterogeneities tailored to a given set of input data. Furthermore, this can greatly assist with respect to the quantity of fracturing...
materials and water used in current field design approaches.

2. Considering permeability, anisotropy with the simulator and its correlated effects on HF propagation can be disadvantageous. This is a major concern especially in thin reservoirs where fracture height containment is a major concern.

3. From an operational design perspective, many operational challenges and field practices could be evaluated within the model. This includes slick water injection, which is a recommended practice for reservoirs relevant to the provided field data. Other potential commonly known challenges include screen out, sand production, sand plug-in formation, and water production.

4. The results from this research can be extended to better understand the observations reported in the literature and field studies with respect to hydraulic fracturing in naturally fractured tight reservoirs. It also allows to predict and diagnose potential behavior or expectations with respect to few constrained responses when encountering complex fracture networks.

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Notes

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