

Multi-Stage, Multi-Wellbore Hydraulic Fracturing Simulation in Naturally Fractured Reservoirs Using Cohesive Zone Model

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Abstract: *Microseismic surveys have demonstrated the abundance of natural fractures where shear slippage occurs due to hydraulic fracturing. These natural fractures and their intersection with hydraulic fractures significantly complicate the optimization of hydraulic fracturing strategies especially in shale resources with multiple simultaneous or sequential stimulation stages. The clusters' hydraulic connection within a stage may substantially influence the hydraulic fracture propagation pattern considering the highly variable perforation efficiencies of clusters. These complexities promote the proposed developments in our poro-elastic cohesive zone models for hydraulic fracturing in Abaqus.*

Our model adopts a validated cohesive traction-separation response for fracture propagation and a well-established, mechanism-based intersection model. The model is integrated with a novel universal wellbore-perforation model for simultaneous and sequential fracturing along three stimulation stages and wellbores. Each stage contains three fracture clusters hydraulically connected through the wellbore during or after the corresponding stage stimulation. The natural fracture (NF) network is retrieved stochastically based on Monte Carlo sampling, and perforation tunnel lengths are modeled using fully damaged cohesive elements at perforation locations.

The model quantified limited cluster stimulation, the activation of a complex NF network, and fluid infiltration depending on the stimulation scenario, wellbore pressure drop, randomly distributed perforation lengths, and fracturing fluid viscosity. The complex stimulation patterns is featured by further control on cluster stimulation in the sequential fracturing case compared to the simultaneous case especially in the presence of non-uniform shaped-charge perforations. This improved model enhances the reliability on numerical simulations for hydraulic fracturing design.

Keywords: *Microseismicity, Poro-elasticity, Reservoir Geomechanics, Natural Fractures, Stress Shadowing Effect, Hydraulic-Natural Fracture Intersections, Pore Pressure Cohesive Zone Model, Hydraulic Fracture Initiation and Propagation, Stimulated Reservoir Volume, Perforation Tunnel Lengths.*

1. Introduction

Hydraulic fracturing stimulation has been widely deployed for the economic production from hydrocarbon-bearing ultra-low permeable shale formations. The design and optimization of these stimulation processes strongly depends on robust computational models because of numerous

controlling parameters and the complexity of the geological formations. As a dominating complexity in the hydraulic fracturing design, the natural fracture (NF) network and connections to the hydraulic fractures may improve or damage the long-term production from the hydrocarbon reservoir. For instance, the damage to the long-term production may occur due to the fluid flow interference of the offset horizontal wells through the NF network induced by primarily independent hydraulic fractures. This interference can be observed frequently in microseismic surveys, e.g. for a four-well pad as shown in Figure 1. In this figure, the events associated with the stimulations along each horizontal wellbore are grouped together by a unique color. Due to the color overlap between all neighboring well couples, the fracture runaway from one wellbore to the other one is eminent.

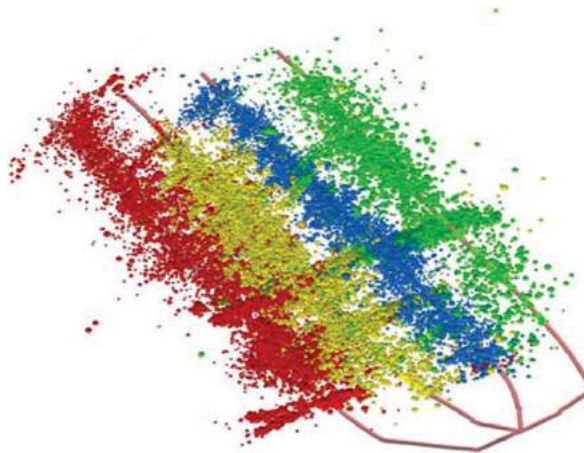


Figure 1. Microseismic events recorded during fracturing in a four-well pad (Manchanda et al., 2014)

In addition to the offset well interference during the hydraulic fracturing stimulation, the hydraulic fractures in a single well may propagate beyond the desired stage boundaries and consequently, restrict the stimulated reservoir volume (SRV) to the near-wellbore areas. Apparently, the existing natural fractures play the dominant role in the diversion of the hydraulic fracture growth to the neighboring stages. This type of fracture interference may be distinguished also in a color-coded microseismic survey as shown in Figure 2. In this figure, the rectangular wireframe boxes show the desired stimulation volume for each fracture stage. Evidently, the stage microseismic events have significantly extended into the neighboring stages.

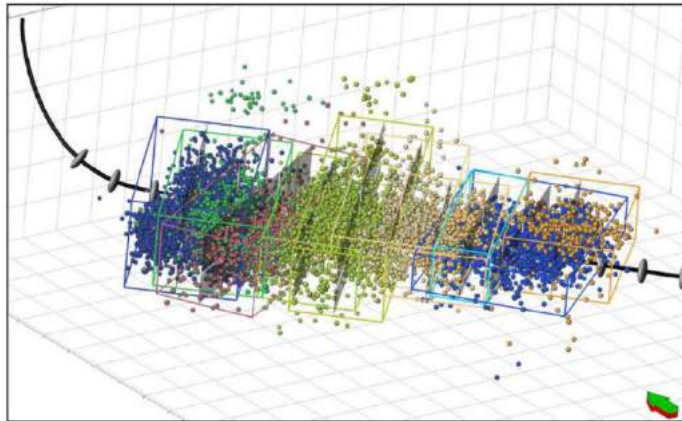


Figure 2. Microseismic events along a sequentially fractured wellbore (Virues et al., 2015). The events associated with each stage are color-coded.

The significant effect of the natural fractures on the hydraulic fracture growth has been indirectly referred to by Warpinski (2013) where he showed the abundance of the interior events as well as the tip-related events in a field data according to Figure 3. As this figure shows, the maximum distance of all events (or the fracture half-length) increases with square root of time whereas the KGD analytical solution provides a $t^{2/3}$ trend for the fracture half-length. This shows that the probable shear slippage of natural fractures during the interior events and fluid infiltration into these induced natural fractures significantly slow down the main hydraulic fracture propagation.

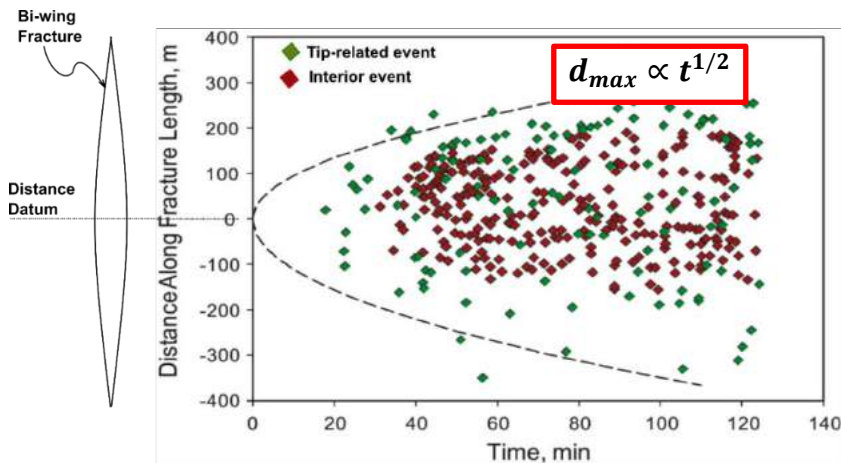


Figure 3. Distance of interior (red) and tip-related (green) microseismic events from the fracture mouth versus time. The maximum distance of all events follows a $t^{1/2}$ trend after Warpinski (2013).

All these observations indirectly confirm the existence of a complex NF network in shale formations, and that the NF effect on the hydraulic fracture propagation cannot be ignored. Moreover, wellbore image logs show un-intentional hydrocarbon production from the induced natural fractures intersecting with the horizontal wellbores. These natural fractures may open their paths towards the wellbore during the stimulation of the favorable hydraulic fracture stage.

Also, the effective length of the conventional perforation tunnels (as the hydraulic fracture initiation spots) significantly influences the fracturing fluid distribution between multiple clusters in a stage, and consequently, the cluster stimulation (Cuthill et al., 2017). Neglecting this effect may lead to the significant overestimation of the overall cluster stimulation.

These complexities promote the development of a new generation of hydraulic fracturing models including the wellbore and fracture intersection models. In this work, these models are called “universal hydraulic fracturing models” where the stage and stimulation scenarios are also integrated within the model through time-dependent connections.

2. Method

The current work integrates a wellbore model, a fracture intersection model, and a fracture-wellbore and stage connection model with a 2D poro-elastic hydraulic fracture propagation model. We used the transient, fully-coupled pore pressure-stress, consolidation analysis in Abaqus/Standard (Abaqus Analysis User’s Guide, 2016). This fracture propagation model contains three horizontal wellbores, three stages in each wellbore, and three fractures (or fracture clusters) in each stage as shown in Figures 4 and 5. We consider two stimulation scenarios: 1) simultaneous fracturing where all three stages receive the fracturing fluid simultaneously; and 2) sequential fracturing where the fracturing fluid flow is directed sequentially to multiple stages.

Figure 4 shows the plan view of the 2D computational domain where the hydraulic fractures, the natural fractures, and the horizontal wellbores are highlighted with red, orange, and blue lines, respectively. Also, the perforation spots, the stage plugs [modeled by fluid pipe connector elements (**FPC2D2**)], and the injection spots are graphically featured by the symbols defined on the upper left corner of Figure 4. The hydraulic fractures and wellbores are spaced by 20 and 50 m, respectively, and connected together through fluid pipe elements (**FP2D2**). These elements in addition to the connector elements and their status at different fracturing stages are graphically shown in Figure 5 which is a magnified section of Figure 4.

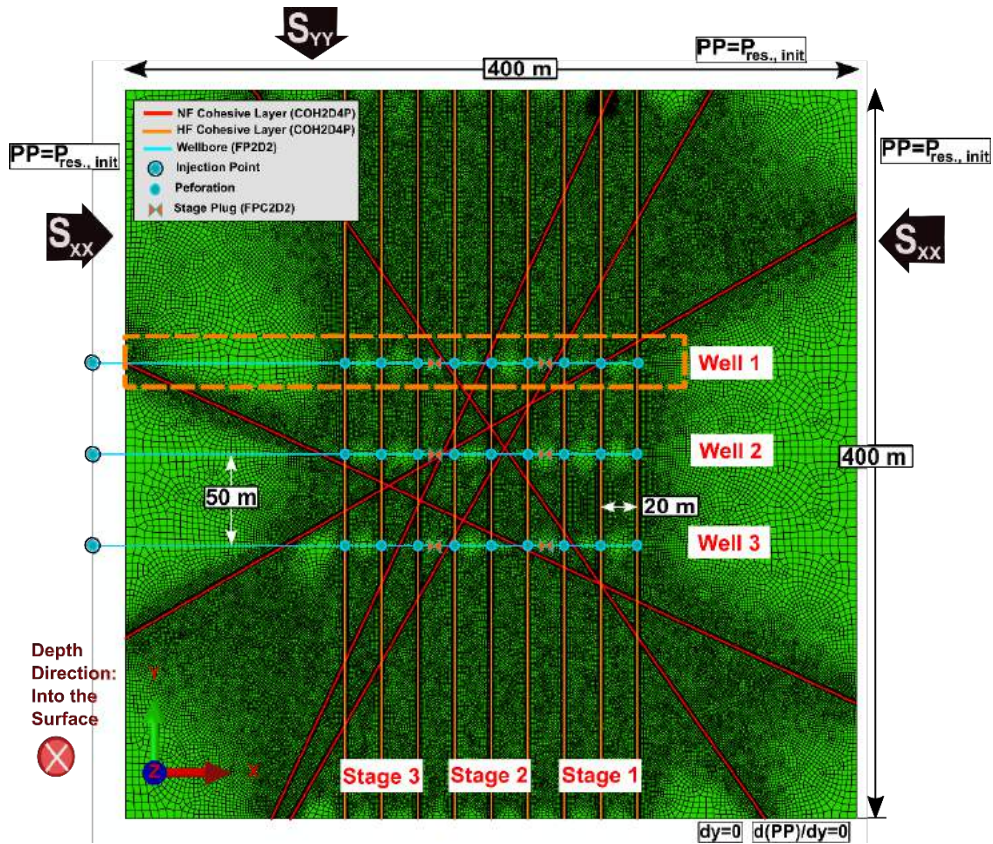


Figure 4. Universal hydraulic fracturing model constructed by 329719 CPE4P, 36441 COH2D4P, 47 FP2D2, and 33 FPC2D2 elements. There are 53 fracture intersections between the cohesive layers associated with nine hydraulic fractures (vertical orange lines) and five natural fractures (oblique red lines). The hydraulic fractures and horizontal wellbores are spaced by 20 and 50 m, respectively. Each fracture stage contains three hydraulic fractures and is isolated by the connector elements. For further model details, the area surrounded by the dashed orange rectangle is magnified in Figure 5.

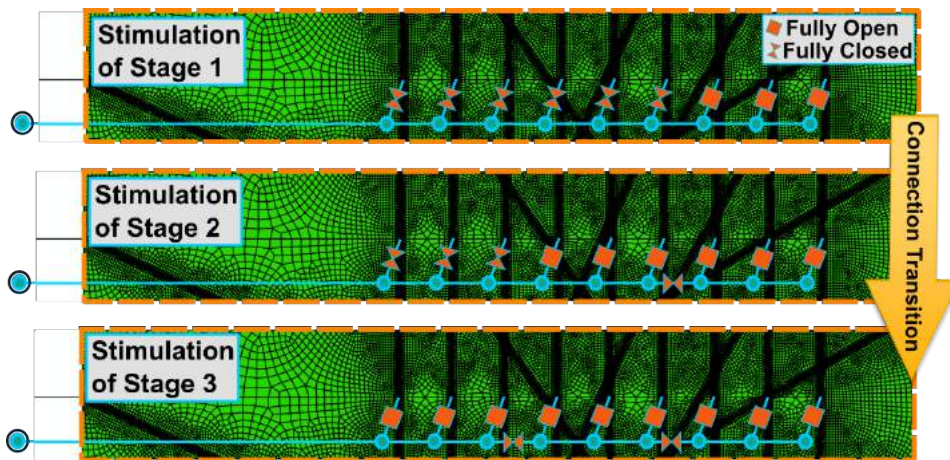


Figure 5. Zoomed area within the dashed orange rectangle in Figure 4. The figure sequence graphically shows the status of the connector elements at various stage stimulations. The dark thick zones in the mesh represent dense elements around the cohesive layers. The fluid pipe and connector elements are graphically highlighted by the blue lines and valve signs, respectively. The orange small squares show open valves whereas the orange butterflies show the closed valves.

For clarity, the characteristics of our so-called “universal hydraulic fracturing model” can be enlisted as the following:

- Pore-pressure cohesive behavior is assigned to the hydraulic and natural fracture space(s) using **COH2D4P** elements. The damage initiation stress, energy release rate, and stiffness for all natural fractures are scaled down by a weakening factor, WNF, from those for the hydraulic fractures.
- The intersection model is implemented based on the middle-edge pore pressure coupling of the cohesive elements at the intersection, which has been comprehensively presented and investigated by Haddad et al. (2016, 2017), and Haddad and Sepehrnoori (2016). This implicit intersection model is capable of developing a variety of fracture intersection behavior as follows: complete crossing; crossing and partial de-bonding of the NF; delayed NF de-bonding after the hydraulic fracture cross of the intersection; and complete de-bonding of the NF and the hydraulic fracture arrest at the intersection. The occurrence of these patterns depends on the following: 1) the in-situ stresses especially the horizontal stress contrast; 2) the poro-elastic material properties; 3) the hydraulic and natural fracture cohesive properties; and 4) the length of the initially open segment of the NF at the intersection (Haddad et al., 2017).
- The wellbore model is integrated using the fluid pipe elements **FP2D2**. These elements sequentially connect the perforations, the NF-wellbore intersections, and the injection point together. Each wellbore ends to one injection point on the left as shown in Figure 4.

- For fluid pipe elements, the **Blasius** method is used which determines the friction factor (f) depending on the Reynolds' number (i.e., Re). Briefly, the friction pressure loss is calculated using the formula $\Delta P = f \frac{L}{D_h} \frac{\rho V^2}{2}$ where L , D_h , ρ , and V denote the pipe length, hydraulic diameter, fluid density, and fluid velocity, respectively. According to the **Blasius** method, f is equal to $64/Re$ for $Re < 2500$, and equal to $0.3164/Re^{0.25}$ for $Re \geq 2500$.
- The fracture-wellbore and stage connection model fully controls the connection between the perforations and the horizontal wellbores as well as the stage connection to the injection point. The complete flow control into the fracture clusters is imposed using 27 fluid pipe connector elements (**FPC2D2**) between the middle-edge nodes of the cohesive elements at the perforations and the adjacent nodes on the fluid pipe elements. Also, the stage flow control along each horizontal wellbore is imposed using two connector elements between three fracture stages.
- For the connector elements, the **Darby3K** method is used to preserve the hydraulic pressure loss dependency on Re , and to implement **valve control** using **UFLUIDCONNECTORVALVE**. Briefly, the hydraulic pressure loss through the connectors is dependent on loss term (K), fluid density (ρ), and fluid velocity (V) according to the formula $\Delta P = K \frac{\rho V^2}{2}$. Here, K is equal to $\frac{K_1}{Re} + K_\infty \left(1 + \frac{K_d}{D_h^{0.3}}\right)$ where K_1 , K_∞ , and K_d are resistance coefficients and user-specified. For simplicity, we assumed K_∞ , and K_d equal to zero.
- The stimulation scenarios (simultaneous or sequential) are selected through scheduling the opening and closing of the connector elements, which is conducted in this work by use of the user-defined subroutine **UFLUIDCONNECTORVALVE**. For instance, in order to open the connector elements with the x-coordinates in the range 0 to 40 m in the total time interval 0 to 1 s, the mentioned subroutine consists of conditional statements as the following:

```

IF (((time(2) .ge. 0.0d0) .and.
$      (time(2) .le. 1.0d0)) .and.
$      ((coords(1) .ge. 0.0d0) .and.
$      (coords(1) .le. 40.0d0))) THEN
      valveOpening = 1.0d0;
END IF

```

For more clarity, Figure 5 graphically shows the opening and closing sequence of the connector elements in a sequential stimulation scenario along Well 1. These connector elements provide a tool to study multiple fracturing scenarios with a single injection point per wellbore.

- The NF network is obtained using an object-based model (Haddad et al., 2015). According to this model, the NF alignment with respect to the average fracture alignment follows a Monte Carlo sampling rule, as shown in Figure 6, which ultimately defines the angle between an NF cohesive layer and the x-axis. Using this method, we distributed the natural fractures around two directions perpendicular to each other which make 60° and 150° with the positive direction on the x-axis.

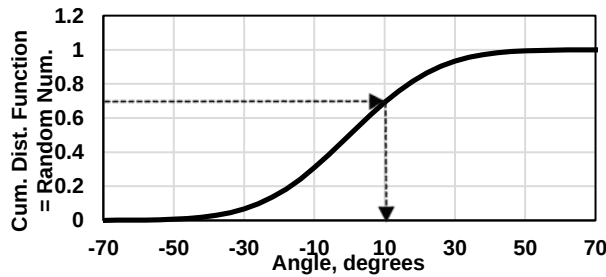


Figure 6. Cumulative distribution function versus angle (with respect to the average NF alignment). For instance, a random number equal to 0.69 generates this angle equal to 10°.

- The cohesive elements adjacent to the perforation points or the intersections must be initialized as fully damaged elements for their gap flow acceptance using initial condition **Initial Gap** in Abaqus. We refer to these elements as initially open segments of the hydraulic or natural fractures in this work.
- The length of the initially open segment of the hydraulic or natural fractures at the injection or intersection points significantly influences the fracture growth. This effect is augmented especially in the presence of a wellbore model as shown in the results section or in the presence of competing fracture branches at the intersection as shown by Haddad et al. (2017). Operationally, this initial open segment (i.e., perforation tunnel) is created to hydraulically connect the formation to the wellbore using shaped-charge jet explosives (Grove et al., 2009). The effective length of the conventional perforation tunnels is not uniform along the wellbore(s) due to the variable material properties (Behrmann and Halleck, 1988) and the irregular shock formation damage (Halleck, 1997). To address this inherent uncertainty in the perforation tunnel length, we initialized variably-sized elements adjacent to the perforation spots as failed elements. Notably, the different sizes of these elements at different perforation spots due to meshing criteria included the random nature of the length of the perforation tunnels. Figures 7 and 8 provide the detailed information about these perforation tunnel lengths.

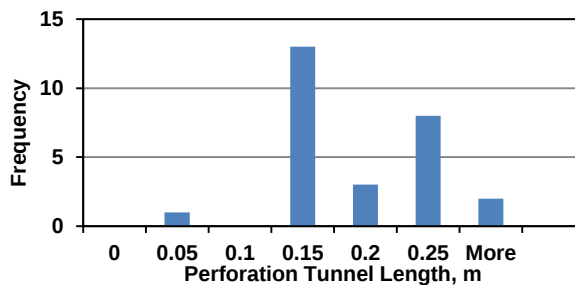


Figure 7. Frequency of the perforation tunnel length. There are 9 perforations per well. Different element sizes at the perforations leads to different perforation tunnel lengths. The average and standard deviation are equal to 0.139 and 0.053,

respectively.

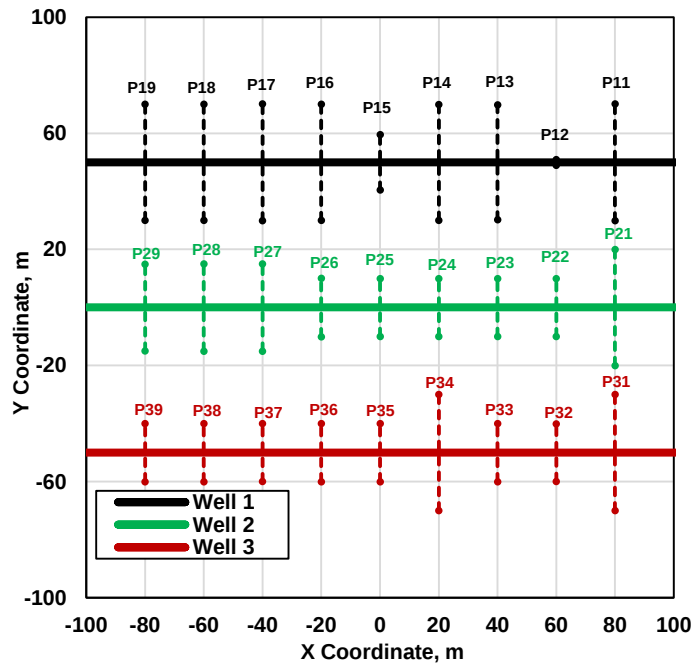


Figure 8. Wellbores (continuous lines) and perforation tunnels (dashed lines). The perforation tunnel lengths are magnified 100 times for demonstration purposes. The perforation tunnels are modeled using fully failed cohesive elements adjacent to the wellbores.

- The injection flow rates, shown in Figure 9, ramp up differently in the different stimulation scenarios depending on the convergence behavior of these cases. However, these injection rate profiles lead to the equal cumulative volume of the injected fluid in both stimulation cases due to the slightly different duration of the stimulation practice.

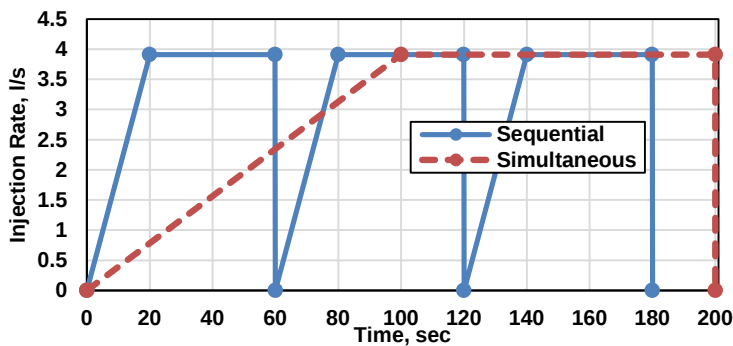


Figure 9. Injection rate for simultaneous and sequential fracturing cases. The total injected volume is equal to 0.587 m^3 for both cases.

3. Results and Discussion

Tables 1 and 2 summarize the computational model properties, and the reservoir characteristics and conditions, respectively. The sequential and simultaneous fracturing cases are similar with regards to all model parameters except for the injection rate profile and the status of the connector elements through time. In both cases, all three wells are stimulated simultaneously whereas the sequential case is distinguished by stimulation according to a sequence: Stage 1 followed by Stage 2, and then Stage 3. In this work, we attempted to demonstrate the significance of the stress shadowing effect on the NF activation. For this purpose, we specified small values for the horizontal stresses, which infers the presence of the formation at shallow depths.

Table 1. Computational model properties

Computational model properties	Value
Number of nodes	403371
Number of elements	366254
Number of linear quadrilateral cohesive elements (COH2D4P)	36441
Number of linear quadrilateral poro-elastic elements (CPE4P)	329719
Number of fluid pipe elements (FP2D2)	47 (along three horizontal wellbores)
Number of fluid pipe connector elements (FPC2D2)	47 (connecting fluid pipe elements to middle-edge nodes at perforations and natural fractures intersecting wellbores)
Maximum injection time (s)	180 (sequential); 200 (simultaneous)
Total injected volume (l)	586.82
Typical CPU time (s)	166037 (using 48 hyper-threads on 24 2.6-GHz processing physical cores)

Table 2. Reservoir characteristics and conditions

Properties	Values
S_{xx} (MPa)	6.90
S_{yy} (MPa)	6.90
Initial reservoir pore pressure (MPa)	3.449
Initial porosity, ϕ (dimensionless) (at zero pore pressure, stress, and zero strain)	0.14
Effective permeability (mD) at initial porosity	0.5
Poisson's ratio, ν (dimensionless)	0.23
Young's modulus, E (GPa)	20.69
Critical stress intensity factor, K_{Ic} and K_{IIc} (MPa $\sqrt{\text{m}}$)	1.76
Damage initiation stress, t_i^0 (MPa)	1.38
Damage initiation stress, t_{II}^0 (MPa)	27.59
Critical energy release rate, G_I^c and G_{II}^c (Pa.m) from Erwin's equation	141.54
Formation grain bulk modulus (GPa)	15.33

Formation fluid bulk modulus (MPa)	220.09
Formation density (kg/m ³)	2262.9
Leakoff coefficient (10 ⁻¹⁰ m ³ /kPa.s)	5.88
NF weakening factor, WNF (dimensionless)	1
Alpha (dimensionless)	60
Injection fluid density (kg/m ³)	1000
Viscosity (cp)	5 (No proppant transport)
Fluid pipe flow loss model	Blasius
Wellbore hydraulic diameter (m)	0.1
Wellbore hydraulic area (m ²)	0.007854
Fluid pipe connector loss method	Darby3K; User valve control for the sequential case
Perforation hydraulic diameter (m)	0.05
Perforation hydraulic area (m ²)	0.00196
Resistance coefficients K ₁ , K ₂ , and K _D in Darby3K	0.1, 0, 0

Figure 10 shows the logarithmic shear strain distribution (as a rough indication of SRV) after 180 seconds of injection in the sequential fracturing case. The smaller apertures of the hydraulic fractures towards the right hand side of the figure reflect the fracturing fluid leakoff into the formation in the isolated first and second stages which preceded the third stage (on the left hand side) in the stimulation process. Here, the fracture intersections have arrested the growth of the second and third hydraulic fractures from the right hand side. Furthermore, the stress shadowing effect of the first stage on the second stage has caused further NF activation in the second stage. Also, the smaller NF distribution density within the third stage on the left hand side has led to straight hydraulic fracture growth. Overall, 22 out of 27 perforations have received significant amounts of the fracturing fluid, which renders 81% (=100%×22/27) perforation efficiency.

As observed in Stage 1 on the right hand side, the variable perforation tunnel lengths in a stage tremendously disturb the uniform fracturing fluid distribution between the fracture clusters in the stage. This problem may be mitigated using the so-called “consistent” perforation technology leading to the perforation tunnels with uniform lengths and diameters (Cuthill et al., 2017).

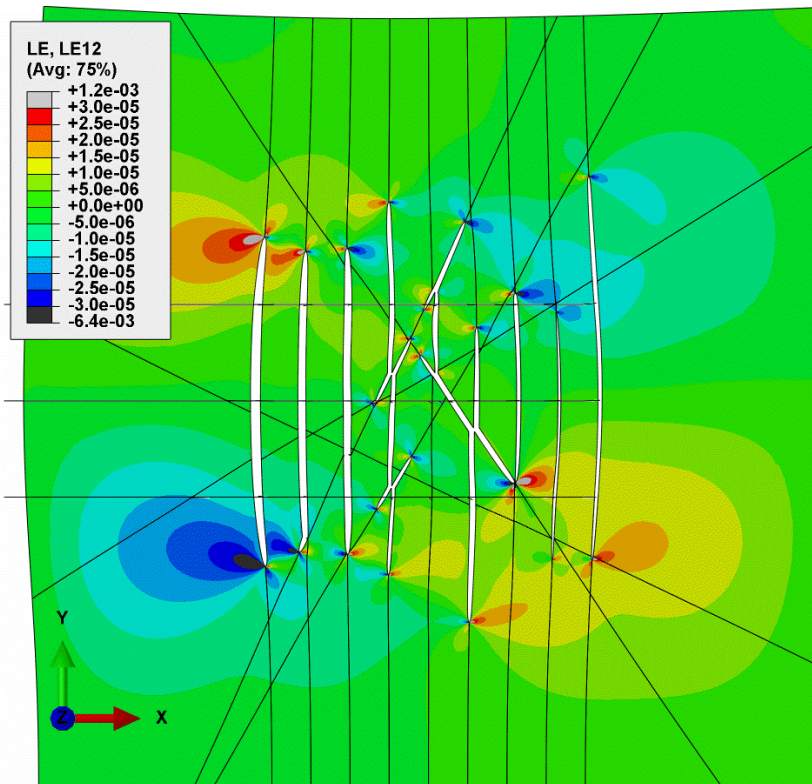


Figure 10. Logarithmic shear strain distribution after 180 seconds of injection in the sequential fracturing case. Displacements are magnified 4000 times for demonstration purposes. Hydraulic fractures have extended from 22 out of 27 perforation tunnels.

Figure 11 presents the logarithmic shear strain distribution after 200 seconds of injection in the simultaneous fracturing case. Here, the more complex stress shadowing effect and the perforation tunnel length distribution have concluded fewer hydraulic fracture growth accompanied by wider openings. Figures 8 and 11 demonstrate the direct relation between the perforation tunnel lengths and the cluster stimulation. Moreover, due to the lower control on the fluid distribution between the fracture clusters in this case compared to the sequential case, we observe a very poor perforation efficiency which is equal to 41% ($=100\% \times 11/27$). Therefore, sequential fracturing is twice as efficient as simultaneous fracturing in initiating hydraulic fractures from the perforations.

In virtue of ultra-low permeabilities of the shale formations, more cluster stimulations significantly outperform creating wider fewer fractures in the production enhancement. Thereby, the sequential fracturing case provides a more promising field development in shale resources.

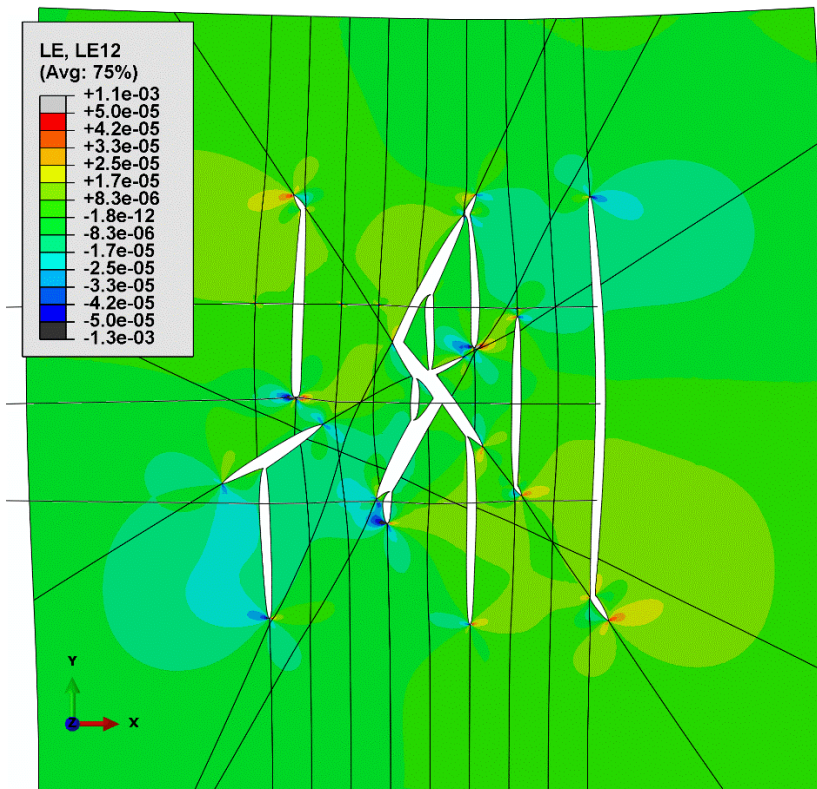


Figure 11. Logarithmic shear strain distribution after 200 seconds of injection in the simultaneous fracturing case. Displacements are magnified 4000 times for demonstration purposes. Hydraulic fractures have extended from 11 out of 27 perforation tunnels.

Figure 12 shows the injection pressure profile through time for different wells and stimulation scenarios. The multiple stage stimulations in the sequential case are associated with multiple injection pressure bumps. The different pressure profiles during the first two stage stimulations for the different wellbores in the sequential case may be associated with the NF activation and the fracture arrest at the intersections. This trend is followed by almost similar fracturing pressures for different wellbores during the last stage stimulation, which is coincident with straight fracture growth as shown in Figure 10. The injection pressure for the simultaneous case ramps up smoothly and maintains at high levels. Apparently, the stress shadowing effect of the fracture growth from Wells 1 and 3 on Well 2 has caused a higher injection pressure for fracture growth from Well 2.

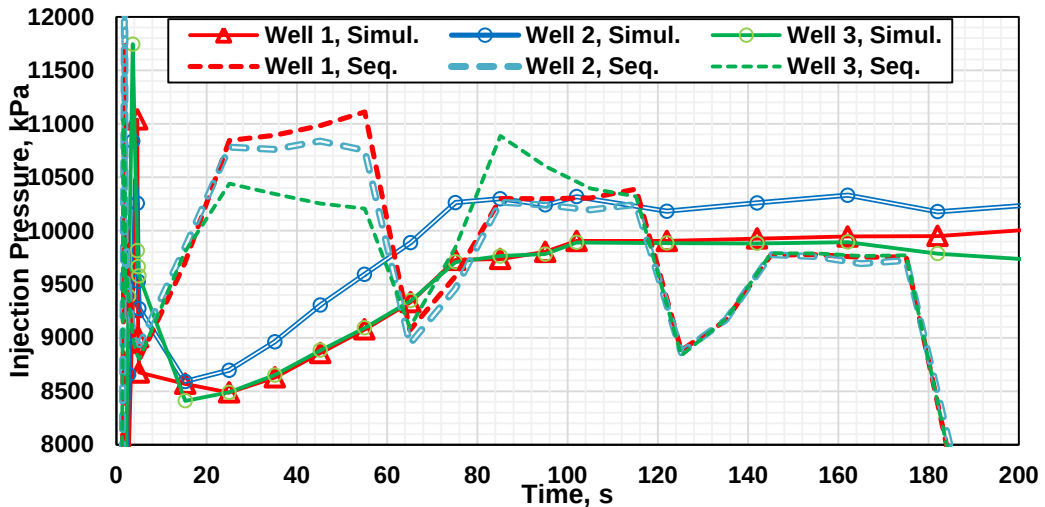


Figure 12. Injection pressure profile through time for multiple wellbores and different stimulation scenarios. “Simul.” and “Seq.” in the legend refer to the simultaneous and sequential fracturing scenarios.

4. Summary and Conclusions

We proposed a novel universal hydraulic fracturing model incorporating the essential components of a developed shale formation such as perforation tunnels, natural fractures and intersections, horizontal wellbores, plug and perf (via connector elements), and external stimulation scenarios (via user subroutines).

Our study on the synthetic simultaneous and sequential fracturing cases shows that sequential fracturing provides more control on the cluster stimulation especially in the presence of the non-uniform perforation tunnel lengths and the perforation connection through the wellbore. Fractures preferentially initiate from the most compliant perforation tunnels which are the longest ones, and the small perforation tunnels may not receive any fracturing fluids leading to lower perforation efficiencies.

5. References

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