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Numerical Investigation of Stimulation from the Injection Well at Utah FORGE Site

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ABSTRACT

A highly deviated injection well, 16A(78)-32, was drilled to a total depth of 10,987 ft at the Frontier Observatory for Research in Geothermal Energy (FORGE) site near Milford, Utah. The lateral tangent was maintained at 65° to the vertical. A series of injection testing was conducted in a 200 ft openhole section at the toe of this well. After a brief hiatus, stimulation by fluid injection will be carried out with three stages near the toe. Numerical modelling should be an essential tool for design and optimization of stimulation strategies that would connect the injection and production wells. These simulations use a lattice-based code, XSite™, which simulates fully coupled hydro-mechanical processes with explicit representation of a discrete fracture network (DFN). The DFN built from a vertical offset well, 58-32, has recently been updated using the image logs acquired while drilling the injection well 16A(78)-32 and data from another vertical offset well, 56-32. Pressure history matching of the injection testing carried out in well 16A(78)-32 provides the basis for refining the DFN. The simulations of stimulation include different pumping rates (10, 20, 40 bpm), different fluid viscosities (2 cP and 20 cP), and different DFN fracture strengths. For the base model with a pumping rate of 20 bpm for 30 minutes, sufficient increase in fluid pressure resulted in hydraulic fracturing, and failure of some area of the DFN, both in tension (opening) and shear (slip). A higher pumping rate of 40 bpm increases extent of hydraulic fracturing, and areas of open and slipping fractures.

1. Introduction

The U.S. Department of Energy selected a location in south-central Utah near the rural community of Milford to develop and test techniques for creating, sustaining, and monitoring Enhanced Geothermal System (EGS) reservoirs (Moore et al., 2019). This field laboratory is the Frontier Observatory for Research in Geothermal Energy (FORGE). From October 2020 to January 2021, the injection well of the injection-production pair, 16A(78)-32 (refer to Figure 1), was drilled, and injection testing including DFIT (Diagnostic Fracture Injection Test) and flowback test were carried out. Within the next two years, a production well of the pair will also be drilled. Both wells of the pair are highly deviated with bottom-hole temperatures near 230°C. After a brief hiatus to analyze reservoir characterization data from well 16A(78)-32, hydraulic fracturing will be carried out near the toe of that well before drilling the second well. Production well 16B(78)-32 will be drilled with a trajectory designed to intersect the microseismic cloud produced during stimulation. A key consideration is the geometry of these “near-toe” fractures in the injection well and the need to ensure effective hydraulic communication between the two wells.

This modeling is based on the distinct element method with an explicit representation of the discrete fracture network (DFN) (Damjanac et al., 2020). The numerical analyses from the pressure history matching for well 58-32 showed that the specifics of the 3D DFN are key to understanding injection pressure (Xing et al., 2021a). Xing et al. (2021b) conducted the preliminary analysis of the hydraulic fracturing treatments for well 16A(78)-32. Then, the DFN has been updated as a result of a detailed study and interpretation of the FMI logs from well 16A(78)-32 and the offset well 56-32.

In this study, the objective is to investigate the stimulation in well 16A(78)-32 using numerical modeling based on the updated DFN. The paper first provides the basic information of well 16A(78)-32, including drilling and injection activities. Then, pressure history matching of injections in well 16A(78)-32 is shown. Finally, simulation of potential stimulation scenarios based on updated DFN in well 16A(78)-32 is presented, and results are discussed. Parametric evaluations include DFN dilatancy, DFN strength, fluid type, and pumping rate.

2. Overview of Well 16A(78)-32

The injection well, 16A(78)-32, is highly deviated and is the first of its kind in granitic rock. Drilling of the well was completed in January 2021. The trajectory of well 16A(78)-32 is shown in Figure 1. The well kicked off (the location where directional drilling operations commence) at 5892 ft measured depth (MD) and started to build 5°/100 ft until it reached 65°. The production casing shoe is at 10,787 ft MD, and there is a 200 ft openhole section behind it. Total depth (TD) of the well is 10,987 ft. True vertical depth (TVD) at the toe is 8560 ft and the temperature at the bottomhole is on the order of 446 °F (230 °C). The horizontal offset is 4074 ft.

After drilling to TD and casing, injection testing, including pump-in/shut-in and pump-in/flowback tests, was conducted in the openhole section of well 16A(78)-32. Inferred closure stress gradients from these tests range from 0.71 to 0.75 psi/ft, which is within the range of those inferred from the openhole section of well 58-32 (Xing et al., 2021c).

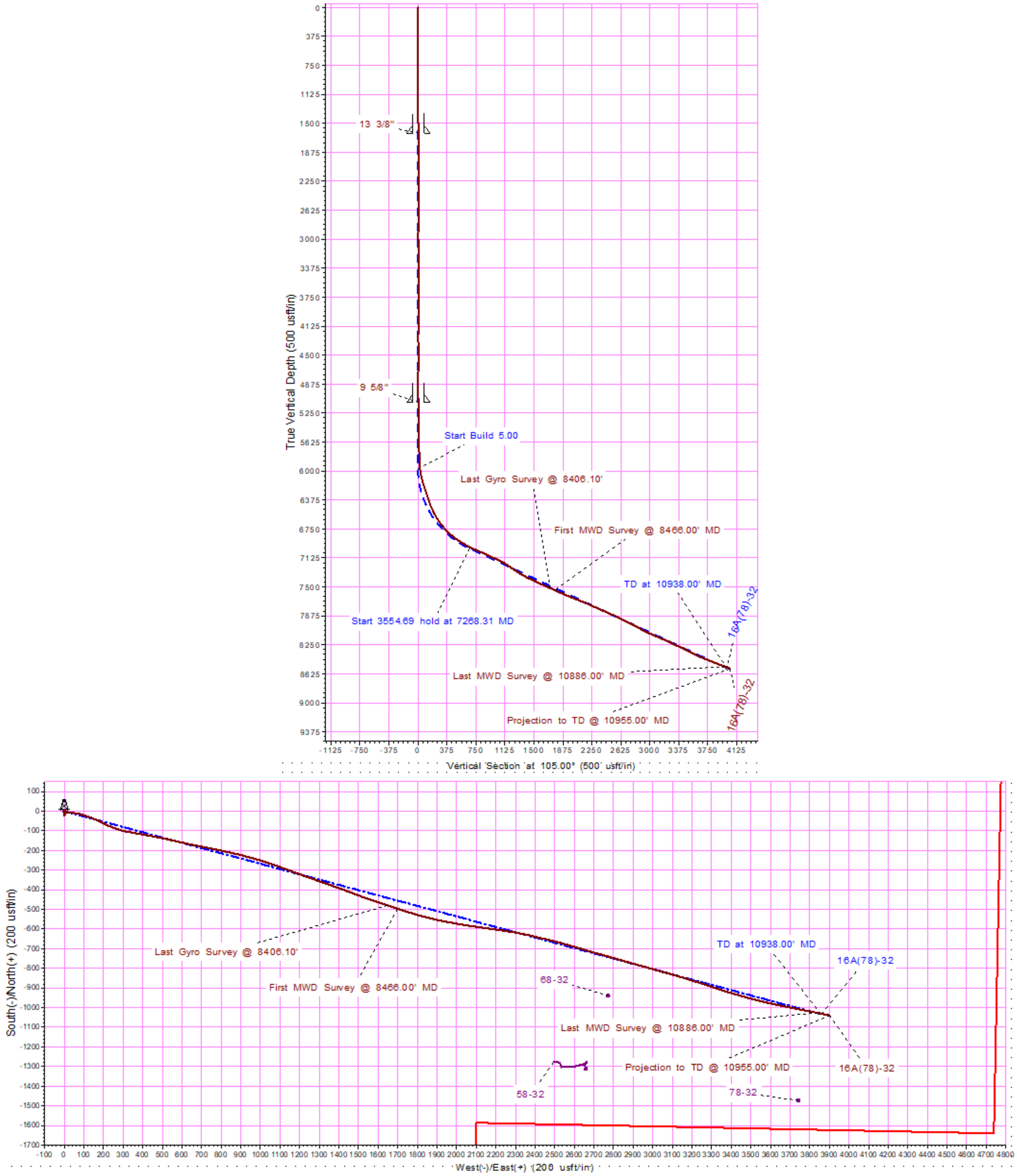

Figure 1. Trajectory of well 16A(78)-32. At the top is the directional profile (approximate elevation view) and at the bottom is the plan view of well trajectory at TD before coring.

2. Pressure History Matching of Injection Tests in Well 16A(78)-32

Pressure history matching of an injection test is often used to calibrate numerical models. There are three injection cycles conducted at the toe of well 16A(78)-32. The details and analyses of these injection tests are documented by Xing et al. (2021c). In this study, pressure history matching is carried out for the DFIT test in well 16A(78)-32. The material properties and initial stress conditions used by the numerical model are listed in Table 1 and Table 2. In this study, an updated DFN is used compared to the DFN used by Xing et al. (2021b). The initial apertures of DFN are shown in Figure 2, ranging from 50 – 200 μm. Discrete stochastic fractures provided in the DFNs have radius values in the 10 to 150 m range and have only four constant orientations.

Table 1. Material Properties used in Numerical Model

Parameter	Value
Young's modulus	55 GPa (8.0×10^6 psi)
Poisson's ratio	0.26
Fracture toughness	3 MPa$\times$m$^{1/2}$ (2740 psi$\times$in$^{1/2}$)
DFN friction angle	37^o
DFN cohesion	0
DFN tensile strength	0
Fluid viscosity	2 cP

Table 2. Initial conditions for well 16A(78)-32 (TVD 8490 ft, 2587.8 m)

Variable	Gradients	Magnitudes
Pore pressure	0.0093 MPa/m (0.41 psi/ft)	24.0 MPa (3481 psi)
Minimum horizontal stress	0.0174 MPa/m (0.73 psi/ft)	42.68 MPa (6190 psi)
Maximum horizontal stress	0.0189 MPa/m (0.84 psi/ft)	48.80 MPa (7078 psi)
Vertical stress	0.0243 MPa/m (1.07 ft/ft)	62.80 MPa (9108 psi)

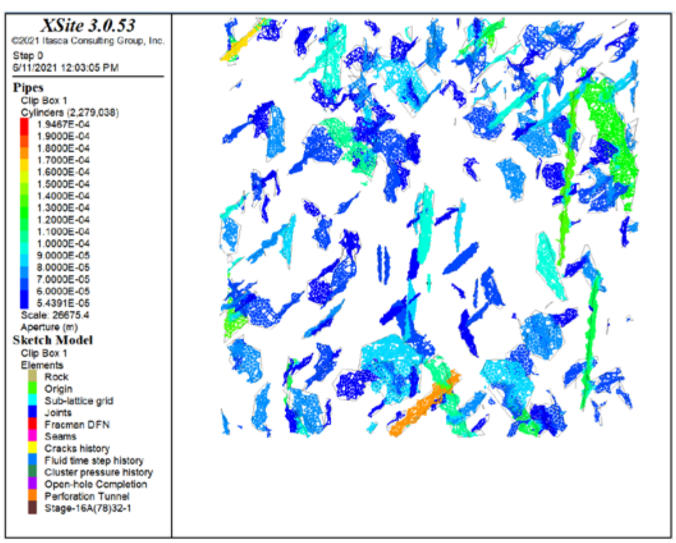

Figure 2. Initial apertures of the DFN.

For the pressure history matching, the model follows the injection procedure of DFIT conducted at the toe of 16A(78)-32. The simulated fluid pressure at the end of simulation (500 seconds after shut-in) is shown in Figure 3. Fluid penetrated the natural fractures that intersect the openhole section. As shown in Figure 4, the pressure history of the numerical results including both the injection and shut-in periods matches well with the field data.

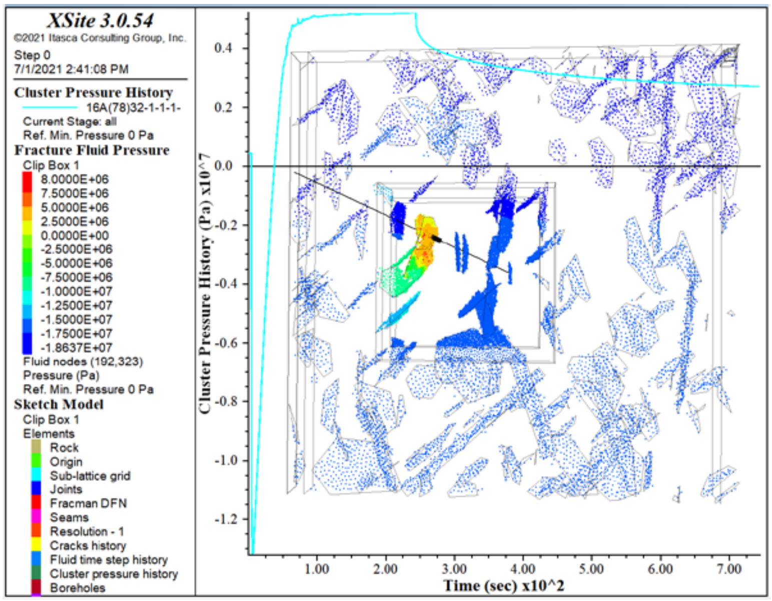

Figure 3. Simulation of the injection test for well 16A(78)-32.

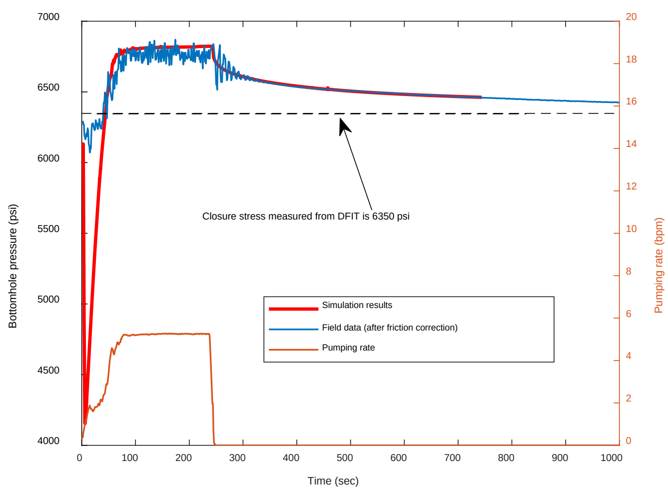

Figure 4. Comparison of the numerical results with the field data for well 16A(78)-32.

3. Simulation of Hydraulic Stimulation for Well 16A(78)-32

Creating a sustainable fluid flow pathway between injection and production wells is the key to the success of an EGS. Depending on the geological conditions and the pumping parameters, the stimulation mechanism can be hydraulic fracturing (failure of intact rock in tension, mode I), opening and slipping (hydro-shearing) of pre-existing joints, or their combination. All mechanisms are investigated. Stimulations in injection well 16A(78)-32 were investigated with the model calibrated by pressure history matching of injections in this well. The effects of DFN dilatancy, pumping rate, DFN strength, and fluid viscosity are investigated.

3.1 Simulation Results of Well 16A(78)-32

3.1.1 Base model

For the base model of simulation of the stimulation, the initial conditions and the material properties are the same as the model used in the pressure history matching. The pumping rate is 20 bpm and the pumping time is 30 minutes. In the base model, DFN is weak with zero cohesion and zero tensile strength. The simulation results of the base model are shown in Figure 5. The height of area with aperture greater than 0.2 mm after stimulation is 235 m above the injection point. The height of slipping fractures above the injection point is 93 m while the height of open fractures is only 73 m. The lateral extent of the stimulated area with aperture greater than 0.2 mm is 130 m. The net fluid pressure is 7.5 MPa.

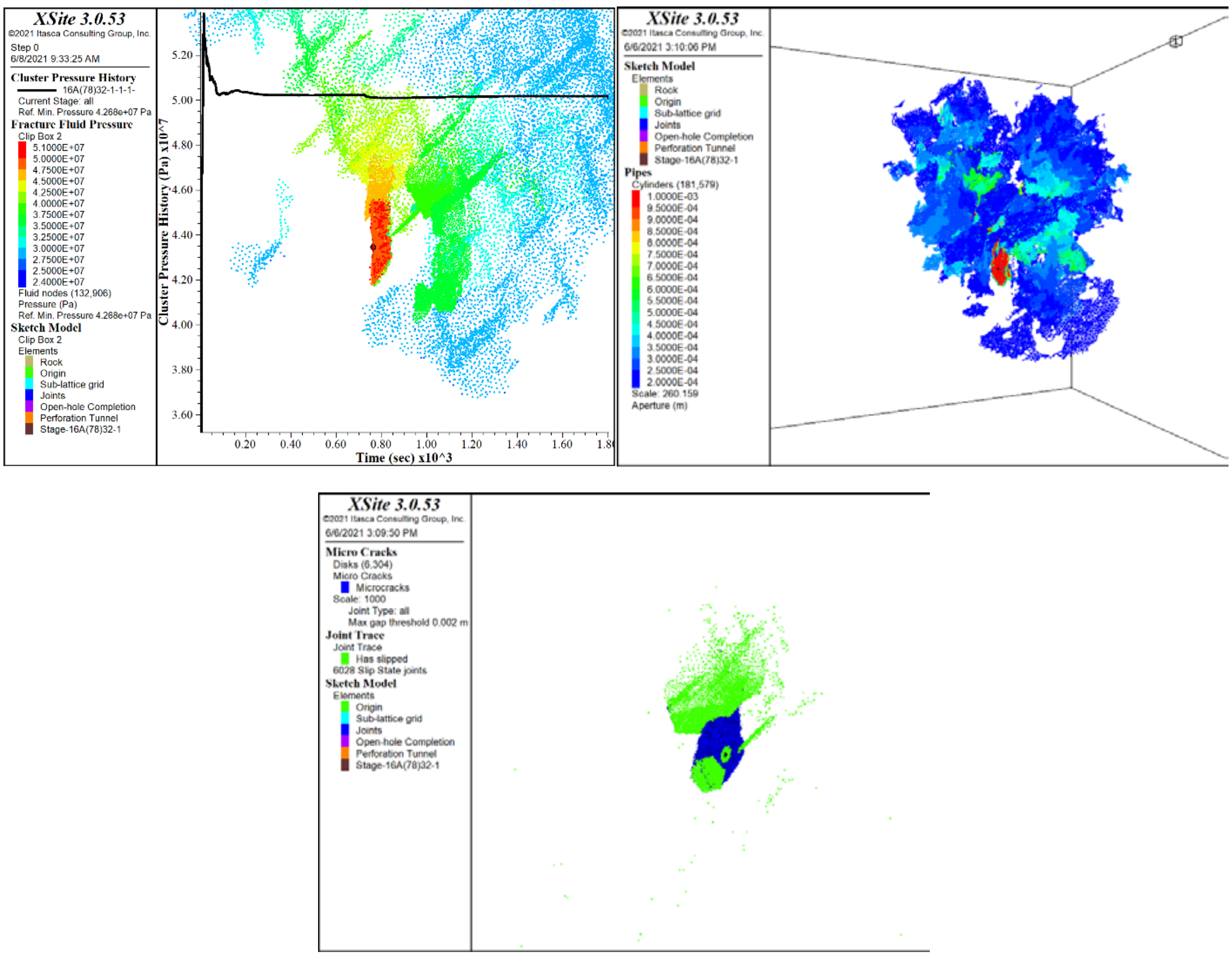

Figure 5. Simulation results of the base model (Case 1): 20 bpm for 30 minutes, no dilation of DFN. Top left: fluid pressure; top right: fracture aperture; bottom: newly created hydraulic fracture (blue) and natural fractures that have slipped (green).

3.1.2 Effect of DFN dilatancy

According to the pressure history matching for well 58-32, DFN dilatancy is a crucial factor that affects the stimulation. Figure 6 shows the simulation results of the case with a 2° dilation angle. As expected, the fluid pressure of the case with the 2° dilation angle is lower than the cases without dilatancy. The fracture apertures of the case with 2° dilation are larger. Due to dilation, the “permeability” of the slipping fractures increases, which results in a decrease in fluid pressure. The slipping area of DFN is similar to the base model without dilatancy but the open area of DFN is smaller.

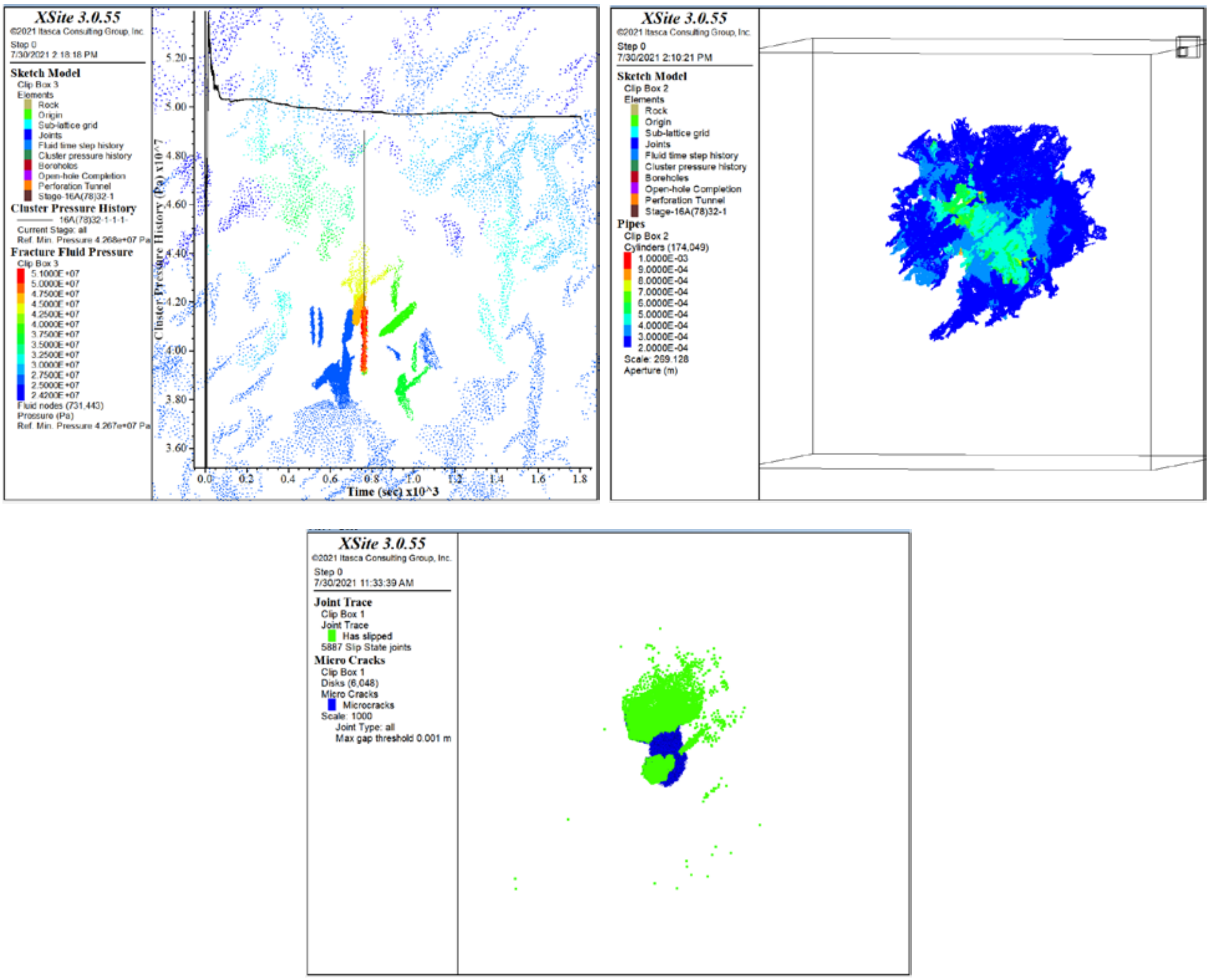

Figure 6. Simulation results of Case 2: 20 bpm for 30 minutes, 2° dilation of DFN. Top left: fluid pressure; top right: fracture aperture; bottom: newly created hydraulic fracture (blue) and natural fractures that have slipped (green). The aperture is larger compared to the no dilatancy case, but there is no preferential pathway.

3.1.3 Effect of pumping rate

Pumping rate could affect the hydraulic fracture and natural fracture interaction. Two cases with pumping rate higher and lower than the base model are investigated. Figure 7 shows the results of a case with a higher pumping rate, 40 bpm. The pumping time is 15 minutes. For the case with the higher rate, the pressure is higher, the fracture aperture is larger, and the slipping and open area of DFN is larger compared to the base case for the same pumped volume.

Figure 8 shows the results for the case with a lower pumping rate — 10 bpm. The pumping time is 60 minutes. As expected, the pressure of the case with the lower pumping rate is smaller. For the same pumping volume, the slipping area and open area of DFN are both smaller than the base model with the higher pumping rate. This trend is different than the one reported by Xing et al. (2021b) that the slipping area of the case with the lower pumping is larger. The difference is due to different DFN intensity and connectivity.

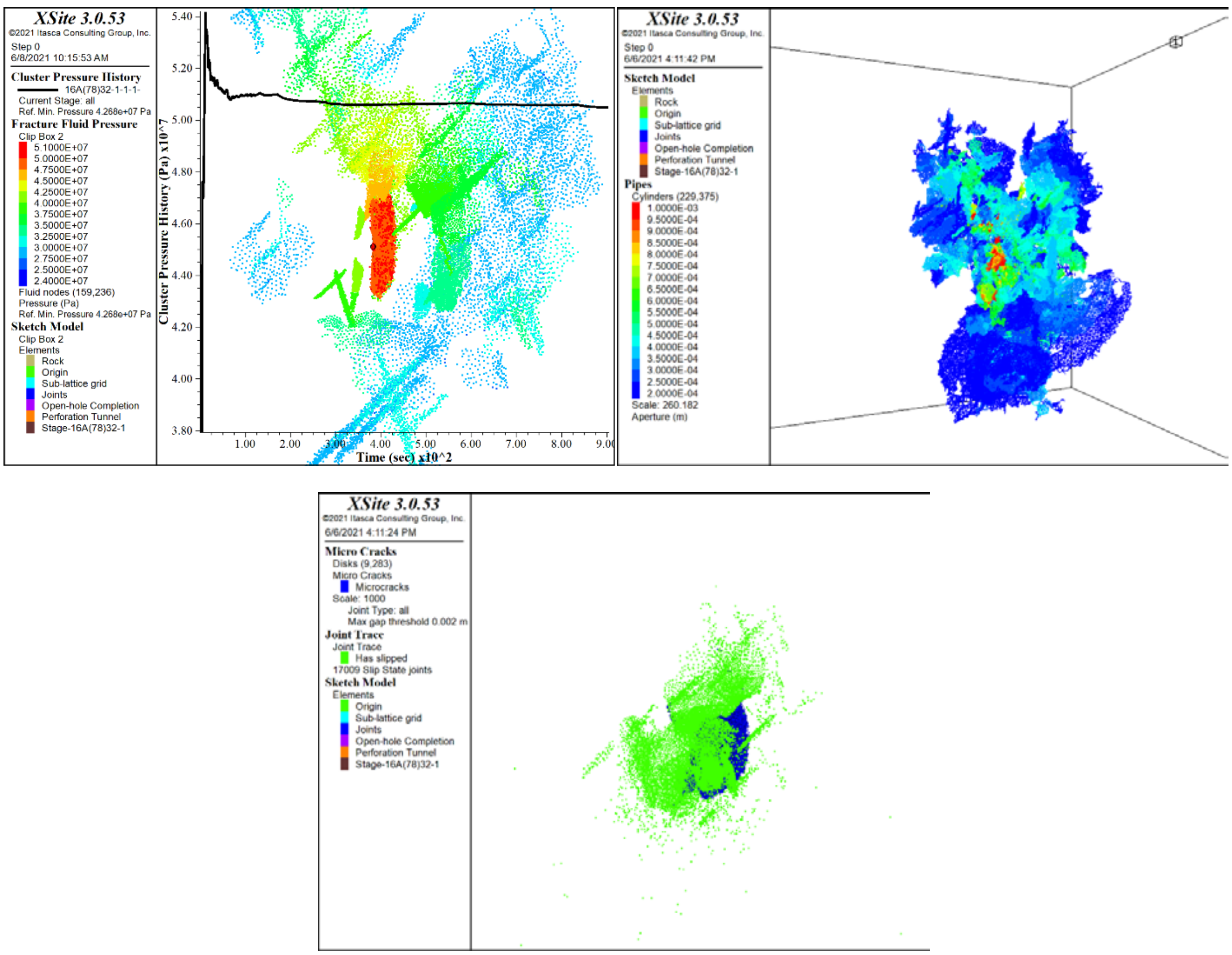

Figure 7. Simulation results of Case 3: 40 bpm for 15 minutes, no dilation of DFN. Top left: fluid pressure; top right: fracture aperture; bottom: newly created hydraulic fracture (blue) and natural fractures that have slipped (green).

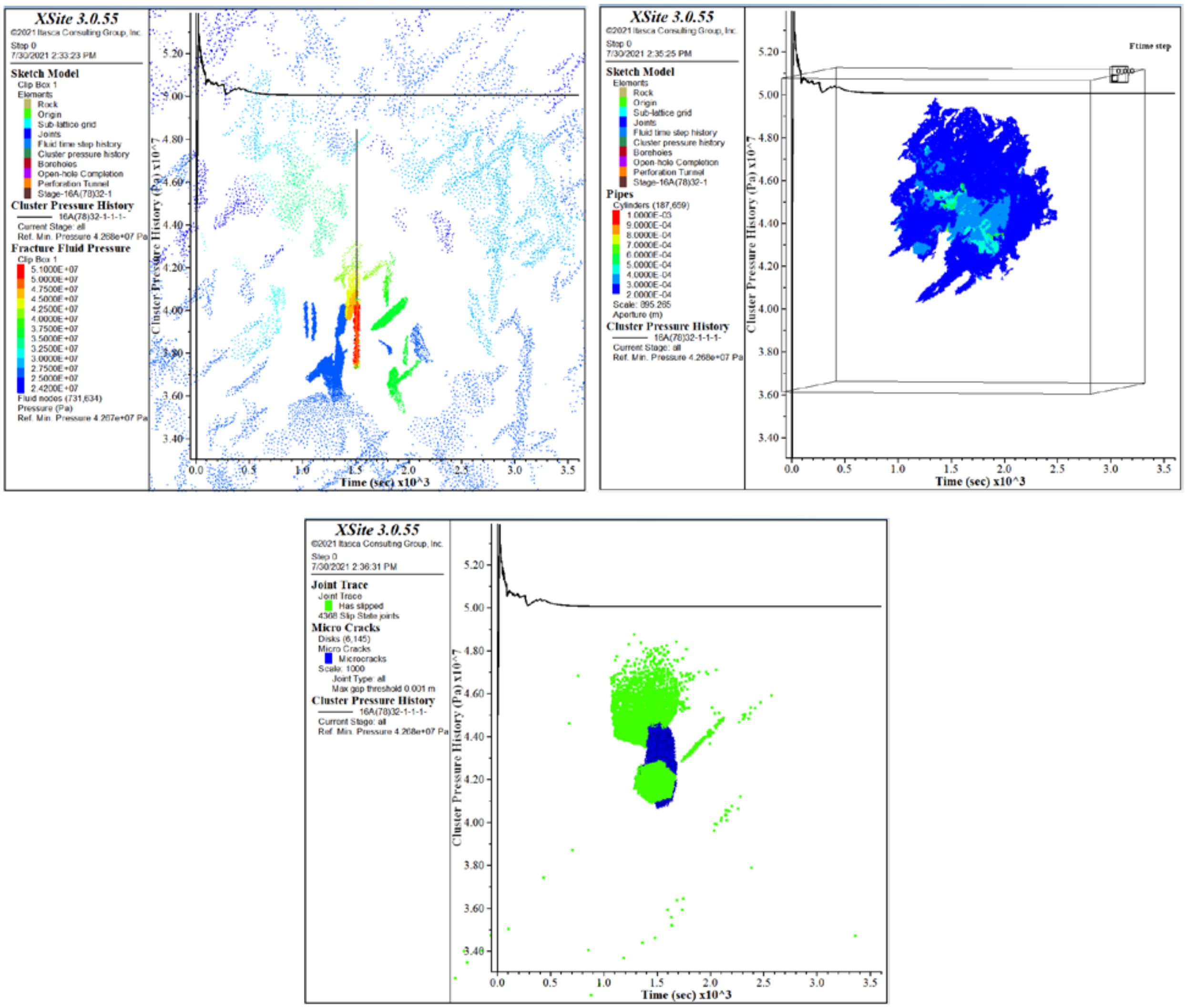

Figure 8. Simulation results of Case 4: 10 bpm for 60 minutes, no dilation of DFN. Top left: fluid pressure; top right: fracture aperture; bottom: newly created hydraulic fracture (blue) and natural fractures that have slipped (green).

3.1.4 Effect of DFN strength

There are uncertainties in the strength of DFN. In the base model, DFN is weak with zero cohesion and zero tensile strength. In this case, a stronger DFN with a cohesion of 10 MPa and tensile strength of 2 MPa is investigated. Friction angle is fixed as 37^{o}. The DFN is also assumed impermeable in-situ. The DFN fractures become permeable only after they fail in tension or shear. The results for stronger DFN are shown in Figure 9.

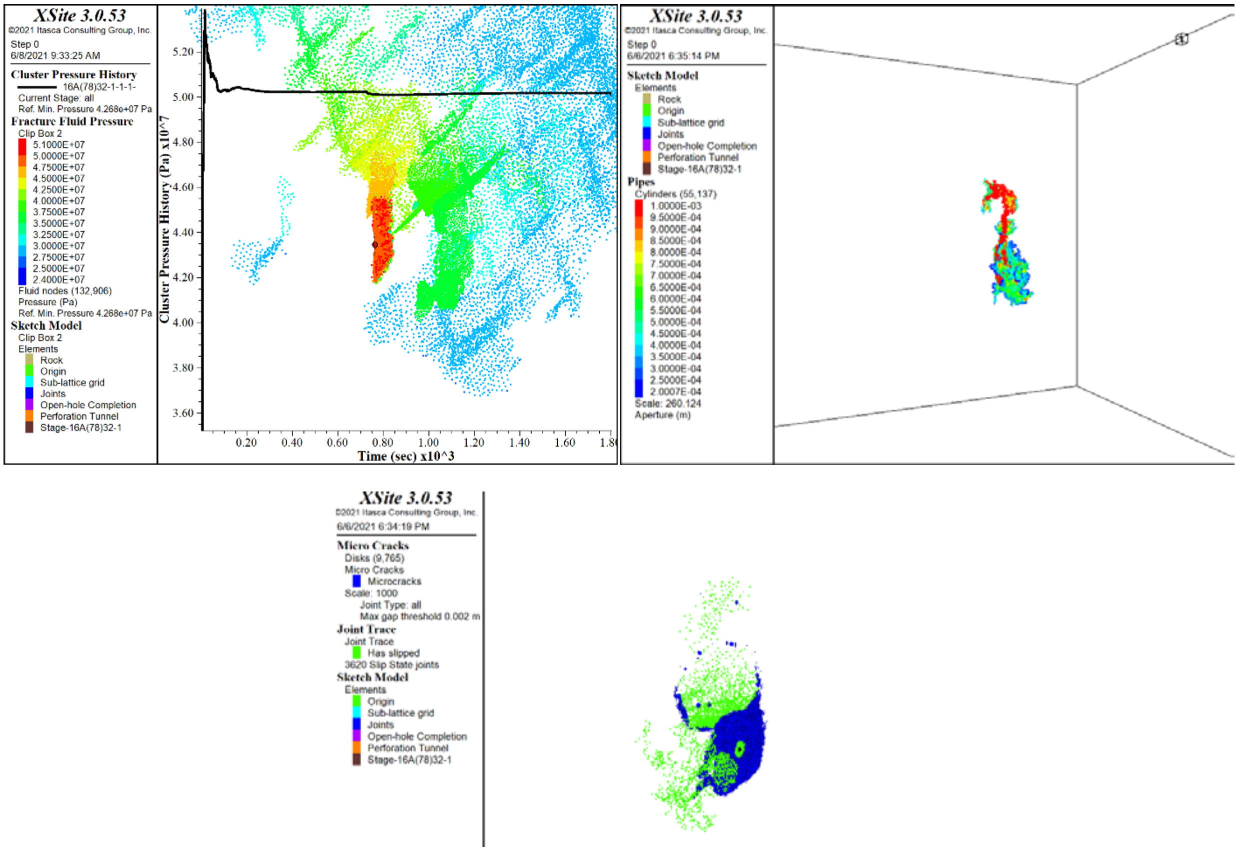

Figure 9. Simulation results of Case 5: 20 bpm for 30 minutes, no dilation of DFN, stronger DFN (cohesion 10 MPa, tensile strength 2 MPa). Top left: fluid pressure; top right: fracture aperture; bottom: newly created hydraulic fracture (blue) and natural fractures that have slipped (green).

The treatment pressure with “stronger” DFN is slightly lower than the case with weak DFN. The area of the fractures with induced apertures greater than 0.2 mm and the area of pressure change is much smaller than the cases with weak DFN. As expected, the area of slipping DFN fractures is smaller due to high cohesion. However, the area of open fractures is much larger than the cases with weak DFN and is even larger than the area of slipping DFN fractures.

3.1.5 Effect fluid viscosity

Fluid viscosity is another important parameter that can be varied during the injection. The viscosity in the base model is 2 cP. Figure 10 shows the results for a case with a larger fluid viscosity of 20 cP. The pumping rate is 20 bpm for 30 minutes. The areas of aperture greater than 0.2 mm and the area of pressure change are much smaller than for the cases with 2cP fluid viscosity because the fluid dissipation is slower for a fluid with higher viscosity (20 cP). However, the areas of both open and slipping fractures are much larger than the cases with smaller fluid viscosity.

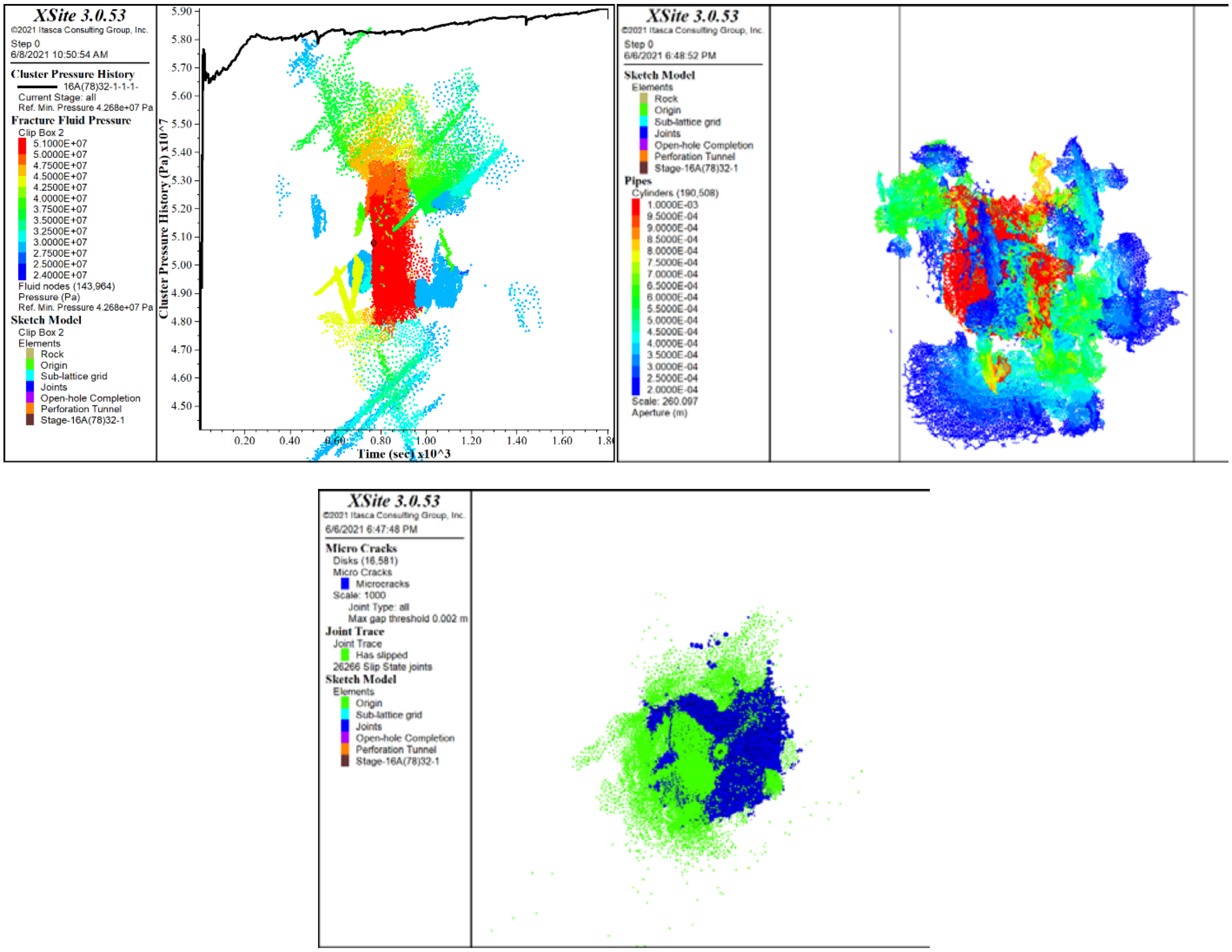

Figure 10. Simulation results of Case 6: 20 bpm for 30 minutes, no dilation of DFN, weak DFN, fluid viscosity 20 cP. Top left: fluid pressure; top right: fracture aperture; bottom: newly created hydraulic fracture (blue) and natural fractures that have slipped (green).

3.2 Summary and Discussion of the Results

A series of simulations for well 16A(78)-32 have been conducted. For the natural fracture networks considered, the formation response to injection was dominated by the DFN. For the base model, the pumping rate is 20 bpm, pumping time is 30 minutes, fluid viscosity is 2 cP. In the base model, the resulting net injection pressure is 7.5 MPa, the height above the injection point defined by induced apertures greater than 0.2 mm is 235 m and the height defined by open fractures is 30 m. The lateral extent of stimulated area with aperture greater than 0.2 mm is 130 m.

Table 1 summarizes fracture height, slipping fracture area, open fracture area, and lateral extent for all the cases. For the cases with a 2° dilation angle for DFN, the net fluid pressures are lower than those without dilatancy because natural fracture permeability increased due to aperture increasing during slip. Generally, the cases with DFN dilatancy resulted in a smaller area of DFN failing in tension but approximately the same slipping area compared to those simulations without dilatancy. Case 2 with weak DFN and dilation has the smallest area of open fractures.

For similar net pressure, slippage of natural fractures tends to impede the opening. Case 6 with higher viscosity (20 cP) has the largest area of slipping fractures and largest area of open fractures because it has much larger net pressure. Case 6 with higher fluid viscosity has the highest pressure and Case 3 with DFN dilation has the smallest pressure. Due to stronger DFN with high cohesion, Case 5 has the smallest area of slipping fractures. In this case the network of connected hydraulic fracture and open DFN extends more than 100 m above the injection point.

Table 1. Summary of the simulation results

Case	Height (m) of aperture > 0.2 mm	Area (m^2) of aperture > 0.2 mm	Height (m) of slip	Slip area (m^2)	Height (m) of open fracture	Open fracture area (m^2)	Lateral extent (m)
Case 1: 20 bpm, 600 bbl, 2 cP, no dilation, weak DFN	235	3.18E+05	93	9700	73	5730	130
Case 2: 20 bpm, 600 bbl, 2 cP, 2^o dilation, weak DFN	235	3.00E+05	93	9441	73	4123	134
Case 3: 40 bpm, 600 bbl, 2 cP, no dilation, weak DFN	193	2.87E+05	92	19356	73	9134	125
Case 4: 10 bpm, 600 bbl, 2 cP, no dilation, weak DFN	280	3.53E+05	75	4329	50	2529	131
Case 5: 20 bpm, 600 bbl, 2 cP, no dilation, strong DFN	110	1.26E+05	108	3999	108	8844	33
Case 6: 20 bpm, 600 bbl, 20 cP, no dilation, weak DFN	121	1.32E+05	93	30137	82	23897	88

There are three indices related to the height of the stimulated fractures above the injection point for the stimulation. The first one is defined by induced fracture apertures that are greater than 0.2 mm; the second one is defined by the slipping of DFN fractures; and, the third one is defined by the open state of fractures. For Cases 1 through 4 with weak DFN and smaller viscosity, the fracture heights defined by the aperture threshold are much greater than those defined by fractures slipping or open state. For Case 5 with stronger DFN, these three fracture height indices give similar results, and the fracture height defined by fracture open state is much larger than those cases with weak DFN.

4. Conclusions

Injection well 16A(78)-32 has been drilled at the FORGE site. Hydraulic fracturing will be carried out near the toe to create a sustainable hydraulic communication between the injection and production wells. Simulations of stimulation for injection well 16A(78)-32 have been conducted. These simulations are based on the DFN constructed from image logging and deep acoustic log interpretations from this well and the offset wells.

The model has been calibrated by pressure history matching the injection tests in well 16A(78)-32. The calibration helps constraining the material properties and initial stress conditions. The pressure trend during the injection is largely affected by the fluid flow and pressure dissipation in the DFN.

These simulations show forward predictions of the formation response to injection in well 16A(78)-32 for the current interpretation of the DFN. In all the cases, the formation response is dominated by the DFN, and failure is the combination of fracture open and natural fracture slipping. For the base model, the pumping rate is 20 bpm, the pumping time is 30 minutes, and the fluid viscosity is 2 cP. The resulting net treatment pressure is 7.5 MPa, the height of stimulated fractures above the injection point, defined by induced aperture greater than 0.2 mm, is 235 m, the lateral extent is 130 m, and the height of stimulated fractures defined by open fractures is 73 m.

For the cases with a 2° dilation angle for the natural fractures, the net fluid pressures are lower than those without dilatancy. Increasing the pumping rate from 20 bpm to 40 bpm resulted in a larger area of open and slipping fractures while decreasing the pumping rate from 20 bpm to 10 bpm resulted in a smaller area of open and slipping fractures. For the case with a “stronger” DFN (10 MPa cohesion), the area of slipping fractures is smaller but the area of open fractures is larger. Increasing fluid viscosity from 2 cP to 20 cP resulted in a much higher injection pressure and hence larger area of slipping and open fractures.

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