Hydraulic Fracturing Scenarios for Low Temperature EGS Heat Generation
From the Precambrian Basement in Northern Alberta

Hannes Hofmann¹, Tayfun Babadagli¹, and Günter Zimmermann²

¹Department of Civil and Environmental Engineering, University of Alberta
²GFZ German Research Centre for Geosciences, Potsdam, Germany

Keywords
Hydraulic fracturing, enhanced geothermal systems, sensitivity analysis, Athabasca oil sands, granite, hot-dry-rocks, hot water generation, reservoir simulation

ABSTRACT
Previous computer simulations identified the characteristics of a fracture network that would allow sufficient heat and fluid transfer for the sustainable and economic use of geothermal heat for oil sands extraction and processing in Northern Alberta (Pathak et al., 2012). Since this type of fracture system does not occur naturally in the region, hydraulic fracturing treatments are needed. In this paper, different hydraulic fracturing scenarios are modeled with a commercial fracturing simulator to examine the dimensions of fracture systems that could be obtained artificially by conventional gel-proppant, water- or hybrid-fracture treatments. The primary objective is to evaluate different treatment approaches for these applications to the conditions existing in Northern Alberta. Additionally, a sensitivity analysis is conducted to evaluate the influence of reservoir and treatment parameters on fracture properties.

Subsequent reservoir simulations show whether these fracture systems could make a sustainable and economical heat extraction possible. Overall, the integration of the results of both models leads to proposed hydraulic fracturing strategies suitable for the conditions expected in Northern Alberta.

1. Introduction
Production and processing of the Athabasca oil sands in Ft. McMurray in Northern Alberta, Canada, requires a considerable amount of hot water. Currently, river water is heated by burning huge amounts of natural gas. The question is whether the required hot water could alternatively be supplied by geothermal energy.

Geothermal heat is already produced on a large scale in regions with favorable conditions, where huge amounts of hot water are extracted from permeable formations at relatively shallow depths (e.g., Ragnarsson, 2005). However, in the Athabasca region, the conditions are more challenging. The temperature at a depth of 5000 m is expected to be between 70 and 120 °C (Marjorowicz and Moore, 2008), and the rocks at these depths are anticipated to be low permeability Precambrian granites.

Previous computer simulations identified the characteristics of the fracture network that would be needed for the sustainable and economical use of geothermal energy for oil sands extraction in Northern Alberta (Pathak et al., 2012). Since this type of fracture system does not occur naturally, we examine in this study the type of fracture systems that could be developed by hydraulic fracturing, using commercial fracture modeling software.

To create such an “Enhanced Geothermal System” (EGS), three main stimulation approaches exist: (1) conventional gel-proppant stimulation, (2) water stimulation, and (3) hybrid stimulation. In the past, water fracturing has been used, almost exclusively, to create EGS in low permeability basement rocks (e.g., Soultz-sous-Forêts (Schindler et al., 2008) and Cooper Basin (Wyborn et al., 2005)). Exceptions are gel-proppant stimulations of a granite in Rosemanowes (Parker, 1999) and of a sandstone formation in Groß Schönebeck (Zimmermann & Reinicke, 2010). However, Rushing & Sullivan (2003) observed that, compared to conventional waterfracs, longer effective fracture half-lengths and higher effective fracture conductivities could be achieved by the hybrid waterfrac technique used in the Bossier Tight Gas Sand Play. The basic parameters, advantages and disadvantages of the three methods, summarized by Reinicke (2009), are given in Table 1.

A sensitivity analysis of the hydraulic and mechanical parameters on the fracture properties was conducted, within the typical parameter range, for 5 km deep granites, to understand the relative importance of the different parameters and to identify further data acquisition needs. Additionally, the influence of the treatment parameters was investigated to identify the appropriate size and design of the treatments. Subsequently, eight different stimulation strategies were tested to determine the most suitable treatment design for two possible scenarios. The resulting fractures were used as input data for a thermal-hydraulic reservoir model to evaluate their effect on reservoir performance in terms of pro-
Table 1. Summary of the treatment parameters, advantages and disadvantages of the three main hydraulic stimulation methods (Reinicke, 2009).

<table>
<thead>
<tr>
<th>Treatment Parameters</th>
<th>Gel-Proppant Fracs</th>
<th>Water Fracs</th>
<th>Hybrid Fracs</th>
</tr>
</thead>
<tbody>
<tr>
<td>Frac fluid viscosity</td>
<td>≥ 100 cP</td>
<td>1 – 10 cP</td>
<td>≈ 100 cP</td>
</tr>
<tr>
<td>Proppant concentration</td>
<td>200 – 2,000 g/l</td>
<td>0 – 200 g/l</td>
<td>200 – 500 g/l</td>
</tr>
<tr>
<td>Fracture half-length</td>
<td>≤ 150 m</td>
<td>≤ 1000 m</td>
<td>≤ 250 m</td>
</tr>
<tr>
<td>Fracture width</td>
<td>1 – 25 mm</td>
<td>≤ 1 mm</td>
<td>1 – 2 mm</td>
</tr>
<tr>
<td>Fracture permeability</td>
<td>10 – 1000 D</td>
<td>10 – 1000 D</td>
<td>10 – 100 D</td>
</tr>
<tr>
<td>Fracture conductivity</td>
<td>0.01 – 25 Dm</td>
<td>0.0001 – 1 Dm</td>
<td>0.01 – 1 Dm</td>
</tr>
<tr>
<td>Reservoir permeability</td>
<td>1 – 1000 mD</td>
<td>≤ 0.1 mD</td>
<td>0.01 – 1 mD</td>
</tr>
</tbody>
</table>

Advantages
- Good control of stimulation results
- Special designs allow large fracture width
- Good control of fluid leak-off
- Stimulation success is difficult to predict
- Proppant placement problems
- Screen-out due to weak proppant transport
- Rapid fracture closure
- Good control of stimulation results
- Increases effective propped fracture length
- Reduced chemical loading of fluids

Disadvantages
- Incompatibility of reservoir fluid with complex frac fluid chemistry
- Ineffective clean-up
- Screen-out of proppant in the wellbore due to high proppant loads
- Stimulation success is difficult to predict
- Proppant placement problems
- Screen-out due to weak proppant transport
- Rapid fracture closure
- Incompatibility of reservoir fluids with frac fluid chemistry
- Ineffective clean-up
- Screen-out of proppant in the wellbore due to high proppant loads

In summary, the main goals of this study were to assess the desired EGS may be obtained by hydraulic fracturing and which fracturing strategy would be most appropriate, and to improve our understanding of how hydraulic stimulations should be undertaken to develop a sustainable source of geothermal energy in this particular depth and formation.

2. Model Parameters

All input parameters were taken from literature since no data is available for the Precambrian basement rocks at these great depths. The rock properties and stress parameters used for the fracturing simulation and the sensitivity analysis are summarized in Tables 2 and 3. The data used for the hydrothermal reservoir simulation is shown in Table 4. Most of the data were obtained from the European EGS research site in Soultz-sous-Fôrets. A permeability of 10⁻³ mD represents fractured granite, and 10⁻⁸ mD is the value taken for fresh granite (e.g., Geraud, 2010).

It is assumed that the vertical stress \( \sigma_v \) [MPa] is the maximum principle stress in a normal stress regime. Therefore, the resulting fractures will be vertical. The magnitude of the minimum horizontal stress \( \sigma_{\min} \) [MPa] was calculated using the following equation (Zoback, 2008):

\[
\sigma_{\min} = \frac{V}{1-V} (\sigma_v - P_p) + P_p , \text{ with Poisson's ratio } V = \frac{V_s^2 - V_p^2}{2(V_s^2 - V_p^2)} \text{ and the vertical stress } \sigma_v \text{ [MPa]} = \rho \text{ g z } g \text{ where } \rho \text{ [kg/m}^3] \text{ is the density of the overburden rocks, g [m/s}^2] \text{ is the gravity acceleration and z [m] is the thickness of the overburden. } V_p \text{ [m/s] and } V_s \text{ [m/s] are the compressional and shear wave velocities, respectively. }

Pore pressure \( P_p \) [MPa] is assumed to be equal to the hydrostatic pressure \( (P_p = \rho \text{ g z }) \). Maximum and minimum values of \( \sigma_{\min} \) were obtained by different Poisson ratios between 0.2 and 0.3 (Table 3). The direction of the induced fractures is perpendicular to \( \sigma_{\min} \) and parallel to \( \sigma_{\max} \), which is presumably NE-SW, as obtained from the world stress map (Heidbach et al., 2008).

Two scenarios were considered. Permeability, porosity, Young’s modulus, Poisson’s ratio and fracture toughness were kept constant over the whole reservoir in both scenarios.

However, in Scenario 1 pressures and stresses increase linearly with depth (Figure 1, left), and in Scenario 2 the stress increases stepwise (Figure 1, right). In both cases the reservoir is assumed to be infinite and homogeneous in the horizontal plane. The initiation depth for both cases is 5000 m, and the initial temperature is 100 °C.
3. Fracturing Simulation

For the fracturing simulations, the software package MFRAC was selected. The simulator is formulated between a pseudo-3D and full 3D model, including a coupling between fracture propagation and proppant transport (Meyer, 2011). The main reasons for this choice are the 3D modeling capabilities, an extensive material database, and the possibility to use the discrete fracture network (DFN) simulator MShale, which may be subject of future studies.

3.1 Sensitivity Analysis

MFRAC supports an auto-treatment design function which calculates a treatment schedule based on input parameters like fluid type, proppant type, and proppant concentration and based on a target parameter like a desired fracture half-length. The treatment schedules for the base cases of Scenarios 1 and 2 were derived by this auto-design function for target fracture sizes of 250 m for Scenario 1 and 500 m for Scenario 2. This function was also used for the sensitivity analysis of the treatment parameters to investigate which parameters should be used to most efficiently reach the target fracture size of 250 m in Scenario 1. The parameter range used for this analysis is given in Table 5.

The fracture width is the average width integrated over the whole fracture area. The studied parameter ranges are given in Tables 2, 3 and 5.

3.2 Treatment Designs for Reservoir Simulations

For Scenario 1, four gel-proppant treatment designs with different proppant concentrations, but the same flow rates and fluid volumes, were simulated to show the effect of different conductivities on the thermal and hydraulic behavior of the system.

For Scenario 2, three treatment designs were simulated (Table 5): (1) a gel-proppant design with high proppant concentrations and high viscosity cross-linked gel; (2) one waterfrac with a high flow rate of 9 m³/min, low proppant concentrations (100 kg/m³), light weight proppants (1.25 g/cm³) and a low viscous fluid (5 cp); and (3) two hybrid fracturing treatments with high (1,000 kg/m³) and average proppant concentrations (350 kg/m³) and water-based low viscosity (5 cp) fluid followed by high viscosity cross-linked gel (1000 cp).

The reservoir simulator input parameters from the fracturing designs are the propped fracture area $A_f$ [km²] that acts as the heat exchanger and the fracture conductivity $K_f$ [mDm] that enhances the flow. The fracture conductivity is the product of propped fracture width ($w$ [m]) and fracture permeability ($k_f$ [mD]): $K_f = k_f w$.

4. Reservoir Simulation

The thermal and hydraulic behavior of the reservoir was modeled using the thermo-hydraulic finite-difference reservoir simulator CMG STARS (CMG Manual, 2012).

A single porosity model was created, including one horizontal injection well (injection rate: 5,000 m³/d) at the center of the model, flanked by two horizontal production wells (production rate: 2,500 m³/d each) intersected by vertical fractures. This approach has not yet been executed in EGS applications, but is commonly used in shale gas production (e.g., Waters, 2009). The promising advantage is that more fractures can be developed in the same formation compared to vertical and inclined wells, which can greatly increase the size of the reservoir. The spacing between the fractures is 200 m to...
avoid significant thermal interference. To reduce boundary effects, a 3,200 m x 3,000 m x 750 m reservoir model was created, with a maximum size of the fractured volume of 2,000 m x 2,000 m x 443 m (Figure 2). The first fracture is located at the beginning of the open-hole section of the parallel horizontal wells, and the last fracture is located at the end of it. All fractures are perpendicular to the azimuth of the wells.

The thermal performance of the system was evaluated by the total heat produced from the reservoir and the bottomhole temperature (BHT) at production wells. The hydraulic performance was studied by the productivity index PI \([\text{m}^3/\text{h}/\text{MPa}]\) of the production wells, which was calculated by dividing the flow rate \(Q \text{ [m}^3\text{]}\) of the well by the pressure drawdown \(\Delta P\) of the bottomhole pressure after 30 years.

For each scenario, the number of fractures was increased from 4 to 10, in steps of 2, to extrapolate the influence of the number of fractures on the performance parameters. This makes it possible to determine the number of fractures needed to achieve the targeted results, which are a PI of 1 l/s/bar or 36 m³/h/MPa, and a BHT at the production well of 70 °C after 30 years of production and injection.

5. Results
5.1 Sensitivity Analysis
5.1.1 Treatment Parameters

First, the influence of the treatment parameters fluid type, proppant type, and proppant mass on the fracture properties has been studied using the auto-treatment design function of MFRAC for Scenario 1. The major observations are summarized in Table 6. Thereafter, for Scenario 2, a sensitivity analysis for all other treatment and reservoir parameters has been performed using manual treatment designs. The results are shown in Figures 5 and 6.

The simulations showed that higher gel concentrations (higher viscosities) are more appropriate for Scenario 1 since this leads to a lower height growth. Low viscosity water-based fluids that are used for waterfrac treatments, and the first pumping stage of hybridfrac treatments, lead to a significant height growth (Figure 3) of up to six times the fracture half-length. Another drawback of low viscosity fluids is that the fracture is not uniformly propped because of the fast settling of the proppants. With time, the horizontal and downward fracture growth slows, and the vertical upper fracture half growth increases significantly.

If the stress was constant over a depth of a couple of hundred meters (Scenario 2), a different fracturing fluid would be more appropriate, because this heavy fluid would lead to a more severe growth of the lower half of the fracture wing.

Performing waterfrac treatments with low viscosity fluids leads to a fast settling of the proppants (Figure 4, left). The heavier the proppant, the faster is the settling and the lower is the final propped area. That is why, for waterfracs, high strength, light weight proppants with densities of about 1.25 g/cm³ are more appropriate (Figure 4, right).

It was observed that the treatment parameters are very important for both fracture area and fracture width (Figure 5 and 6). For the area, the injected fluid volume is one of the main parameters that can be increased to increase the surface area of the fracture. Fracture width is mainly influenced by the fluid type. Higher fluid viscosities lead to an increase in fracture width of up to 166 %. But this would also lead to a decrease in fracture area of 11 %. High

![Figure 2. 3D reservoir model including the position of the horizontal injection well (I1, blue), the horizontal production wells (P1 and P2, red) and the vertical hydraulic fractures (grey).](image)

![Fracture Conductivity (FOEJ)](image)

Table 6. Major observations of the sensitivity analysis performed for the treatment parameters for Scenario 1 with the auto-treatment design function with constant reservoir properties (base case).

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Major Observations</th>
</tr>
</thead>
<tbody>
<tr>
<td>Fluid Type</td>
<td>Higher viscosities more appropriate for unconfined formations (Scenario 1)</td>
</tr>
<tr>
<td></td>
<td>Lower viscosities more appropriate for confined formations (Scenario 2)</td>
</tr>
<tr>
<td></td>
<td>Highest influence on fracture width</td>
</tr>
<tr>
<td>Proppant Type</td>
<td>HSP recommended because of high closure stress</td>
</tr>
<tr>
<td></td>
<td>LWP recommended for waterfracs because of better proppant distribution</td>
</tr>
<tr>
<td>Proppant Mass</td>
<td>Linear relation between proppant concentration and mass, width, permeability and conductivity</td>
</tr>
</tbody>
</table>

![Figure 3. Final fracture area and conductivity showing significant fracture height growth in unconfined reservoirs (Scenario 1) resulting from the use of low viscosity fluids.](image)
flow rates are favorable to increase both fracture area and width. The depth has more influence on the fracture area than on the width. A 20% bigger fracture area could be achieved with the same treatment design when stimulating at a depth of 4000 m as compared to 6000 m.

### 5.1.2 Reservoir Parameters

The fracture area is mainly controlled by the fluid leak-off behavior. Consequently, the hydraulic parameters which directly influence the fluid leak-off have the biggest influence on the fracture area. If the leak-off is high, a wall-building fluid should be used and high fluid volumes are needed. The influence of the hydraulic parameters on the fracture widths is smaller than on the fracture area. For the width, the mechanical parameters, especially Young's modulus, are more important.

The growth of fracture height is of particular interest because the goal is to induce a fracture which is long enough that the water pumped through this fracture from the injection to the production well has enough time to extract the heat from the rock.

Several different simulations show that the growth of the upper half is unconfined if the stress increases linearly with depth (Scenario 1) and the growth of the lower half is unconfined if the stress is constant. Height growth confinement is obtained if the stress is lower within the target formation than on top and at the bottom of the target formation. A stress difference of 5 MPa is a sufficient confinement for a low viscosity fluid in our simulations. This observation is independent of all reservoir parameters within their studied range. Only higher viscosity fluids have been able to overcome this confinement.
these height growth barriers. For them, a stronger confinement would be necessary.

5.2 Hydraulic Fracturing Simulations

Eight different fractures derived from different treatment designs were used for the reservoir simulations (Table 7). In the first four gel-proppant treatments, which were simulated in Scenario 1, only the fracture conductivity is different because of the different proppant masses used. The next four treatments were derived from different treatment types used in Scenario 2, resulting in different fracture conductivities and geometries.

5.3 Reservoir Simulations

These fractures were implemented in four different ways, as shown in Figure 7. In the first fracture system, the fractures of Scenario 1 were implemented with the production wells at the end of each fracture wing. In the fracture system 2, the fractures of Scenario 1 (250 m half-length) and Scenario 2 (500 m half-length) were implemented assuming that for Scenario 1 all three wells were fractured with the same treatment, and for Scenario 2 that only the injection well was fractured and the production wells are located in the middle of each fracture wing. Fracture system 3 was derived by implementing Scenario 2 fractures of the injection well, with the production wells located at the border of each fracture wing. For fracture system 4, Scenario 2 fracture treatments were implemented for injection and production wells.

In all scenarios, the productivity index (PI) increases linearly with the number of fractures (Figure 8). Higher permeability fractures increase the productivity and a lower number of fractures is needed. However, with only four fractures, the PI is lower than 30 m³/h/MPa for all cases. The fracture conductivity obtained by the water fracturing treatment (Scenario 2d) is too low to maintain a reasonable productivity. Therefore, this scenario was omitted from further investigation.

The final BHT at the production well and the cumulative produced heat increase when the heat exchanger area and fluid residence time are increased by increasing the number of fractures, the fracture height or the fracture length (Figure 9). It was also observed that lower flow rates and higher well separations increase the final BHT significantly.

The relationship between the total fracture area and the BHT, as well as the cumulative heat produced after 30 years, is shown in Figure 10. Most of the scenarios achieve a final BHT of more than

<table>
<thead>
<tr>
<th>Scenario</th>
<th>Treatment Type</th>
<th>Proppant Mass [t]</th>
<th>Half-Length [m]</th>
<th>Height [m]</th>
<th>Fracture Conductivity [mDm]</th>
</tr>
</thead>
<tbody>
<tr>
<td>1a</td>
<td>Gel</td>
<td>2520</td>
<td>250</td>
<td>400</td>
<td>986</td>
</tr>
<tr>
<td>1b</td>
<td>Gel</td>
<td>1536</td>
<td>250</td>
<td>400</td>
<td>581</td>
</tr>
<tr>
<td>1c</td>
<td>Gel</td>
<td>678</td>
<td>250</td>
<td>400</td>
<td>208</td>
</tr>
<tr>
<td>1d</td>
<td>Gel</td>
<td>222</td>
<td>250</td>
<td>400</td>
<td>96</td>
</tr>
<tr>
<td>2a</td>
<td>Gel</td>
<td>4600</td>
<td>500</td>
<td>443</td>
<td>783</td>
</tr>
<tr>
<td>2b</td>
<td>Hybrid</td>
<td>2630</td>
<td>500</td>
<td>208</td>
<td>933</td>
</tr>
<tr>
<td>2c</td>
<td>Hybrid</td>
<td>621</td>
<td>500</td>
<td>234</td>
<td>161</td>
</tr>
<tr>
<td>2d</td>
<td>Water</td>
<td>141</td>
<td>500</td>
<td>208</td>
<td>7.6</td>
</tr>
</tbody>
</table>

Figure 7. Top-view of the different kinds of fracture systems (gray lines) with the horizontal injection well (blue) in the middle, flanked by two horizontal production wells (red) with changing position.

Figure 8. Influence of the number of fractures on the productivity index for all eight scenarios and all four fracture systems.

Figure 9. Influence of the number of fractures on the bottomhole temperature at the production well (left) and the cumulative heat produced (right) after 30 years of production.

Figure 10. Relationship between the total fracture area and the BHT, as well as the cumulative heat produced after 30 years.
A significant increase in fracture area above 5 km$^2$ does not change the cumulative produced heat much more. The upper limit as constrained by the production rates is 1.6E16 J.

With the linear relationships between the number of fractures and the PI as shown in Figure 8, the number of fracture treatments which are needed to achieve a PI of 36 m$^3$/h/MPa was calculated for each scenario (Figure 11, left).

To create fracture system [2], obviously the least number of treatments is needed for Scenario 2. For fracture system [1] the least treatments are necessary for scenarios 1a and 1b. The number of fractures needed increases significantly with decreasing conductivity. Scenario 2a is an exception because here the fracture height is almost twice the size of Scenario 2b, reducing the number of fractures needed. The upper boundary of fracturing treatments that can actually be performed strongly depends on the possible length of the horizontal section because the fractures should be separated at least 200 m from each other to avoid too strong thermal interference.

Because horizontal drilling is expensive, the length of the horizontal section as shown in Figure 11 (right) was calculated by multiplying the number of treatments with the distance between two fractures (200 m). All cases with a length below 2,500 m (Scenarios 1a, 1b, 2a, and 2b) are assumed to be favorable.

Because the high strength proppants used in these scenarios are very expensive, the total amount of proppants needed was calculated as well (Figure 12). From this diagram, one may observe that, for the fracture system [1], the least amount of proppants is needed for Scenario 1. For Scenario 2, on the other hand, the least amount is necessary to create system [2]. System [2] (Scenario 1) and system [4] (Scenario 2) include the fracturing of all three wells, which results in much higher amounts of proppants.

The lowest number of treatments needed to achieve the desired PI were found for Scenario 2a and 2b to develop fracture system [2], and for Scenario 1a and 1b to develop fracture system [1] (Table 8). However, since the heat exchanger area is lowest in these scenarios due to the least amount of fractures and the flow rate through each fracture is higher than for scenarios with more fractures, the total produced heat as well as the final BHT at the production well are less than for most other cases. For Scenario 2a [2], almost twice as much proppants were used to obtain an area which is about twice as big as in Scenario 2b [2]. This leads to a significantly higher final temperature above 70°C. For Scenario 1 and fracture system [1] treatment design 1b may be preferred because less proppants are needed and more heat can be produced, as compared to design 1a, even though the horizontal section has to be at least 600 m longer.

**Table 8.** Simulated scenarios with the least number of treatments necessary to achieve a productivity index of 36 m$^3$/h/MPa.

<table>
<thead>
<tr>
<th>Scenario [Fracture System]</th>
<th>Number of Treatments</th>
<th>Total Proppant Mass [t]</th>
<th>Length of Horizontal Section [m]</th>
<th>Total Heat Produced [x 10$^{16}$ J]</th>
<th>Final BHT at Production Well [°C]</th>
</tr>
</thead>
<tbody>
<tr>
<td>2b [2]</td>
<td>6-May</td>
<td>13,150 - 15,780</td>
<td>1,000 - 1,200</td>
<td>0.96 - 1.06</td>
<td>63 - 67</td>
</tr>
<tr>
<td>2a [2]</td>
<td>6-May</td>
<td>23,000 – 27,600</td>
<td>1,000 - 1,200</td>
<td>1.21 - 1.29</td>
<td>74 - 78</td>
</tr>
<tr>
<td>1a [1]</td>
<td>8-Jul</td>
<td>17,640 - 20,160</td>
<td>1,400 - 1,600</td>
<td>1.23 - 1.29</td>
<td>75 - 78</td>
</tr>
<tr>
<td>1b [1]</td>
<td>12-Nov</td>
<td>16,896 - 18,432</td>
<td>2,200 - 2,400</td>
<td>1.41 - 1.44</td>
<td>84 - 86</td>
</tr>
</tbody>
</table>
6. Conclusions and Remarks

The aim of this study was to investigate the influence of treatment and reservoir parameters on the fracturing performance, and to propose stimulation concepts, for the existing conditions in Northern Alberta. Based on the sensitivity analysis and the reservoir simulations of eight different scenarios and four different fracture systems, some conclusions can be drawn with respect to the three main treatment types.

The following conclusions with impact on gel-proppant treatments were derived:

- Gel-proppant fracs are not recommended for confined reservoirs, because high viscosity fluids are more likely to overcome stress confinements.
- On the other hand, if the target formation is not confined, gel-proppant fracs should be used because of the lower height growth compared to the other treatment types.
- If short fracture lengths are sufficient (<250 m), gel proppant fracs may be suitable.
- Main advantages are a good control of the fracture growth and a good proppant distribution.
- The main disadvantage is the lower possible fracture area as compared to the other treatment types.

The following conclusions with impact on waterfrac treatments were derived:

- For waterfracs, light-weight (e.g., 1.25 g/cm³) high strength proppants are recommended to achieve a better proppant distribution within the fracture due to a reduction in proppant settling velocity.
- The fracture conductivity derived from the simulated waterfracs is too low to maintain high enough flow rates through the reservoir. This may be caused by a lack of an adequate modeling approach.
- It may be reasonable to use waterfracs if the reservoir is critically stressed and failure in shear is more important than tensile failure, and a self-propping is likely to occur.

The following conclusions on hybrid stimulation treatments were derived:

- Hybrid fracturing treatments are the recommended method to stimulate confined formations.
- Similar fracture areas, as developed by water fracturing and fracture conductivities from gel-proppant fracturing, can be developed by pumping low viscosity fluid first to create the fracture and high viscosity fluid with proppants afterwards to widen the fracture and transport the proppants.

Also the fracture development based on different stress scenarios was studied and the following observations on fracture development were made:

- The influence of stress barriers and leakoff-zones is very important for the fracture geometry.
- With constant stress, the fracture develops downwards because of the high density of the fluid-proppant mixture. To reduce this effect low viscosity fluids and light weight proppants may be used.
- If the stress increases linearly with depth the fracture develops upwards because of the lower stress at lower depth. To reduce this effect high density proppants and fluids may be used.
- If the fracture height growth is constrained by stress barriers or leakoff zones, the fracture will develop horizontally and high half-lengths can be obtained.
- Only the treatment fluid changed the influence of the stress barrier. All other parameters don’t change it significantly.

The reservoir performance was studied using a commercial three-dimensional thermal-hydraulic reservoir simulator. Based on the simulations of different fracture types and systems, the following observations on reservoir performance were made:

- For the temperature of the produced fluid the fracture surface area, flow rates and well separations are the most important variables; fracture conductivity has no influence.
- For the pressure development and therefore the productivity of the wells, the fracture conductivity is the crucial parameter. Fracture area has less influence here.
- Productivity index and injectivity index increase linearly with the number of fractures.
- Sustainable EGS triplets could be simulated for 30 years with the following minimum parameters: 5 separate treatments, 250 m half-length and well spacing, 500 mDm fracture conductivity, 10,000 t total proppant mass, 1.6 km² fracture surface area, 1,000 m horizontal well section, 200 m fracture separation, 5,000 m³/d injection and 2,500 m³/d production rate per well.
- The productivity of the two production wells should be enhanced by smaller treatments to improve the near wellbore permeability rather than conducting the same treatments for all three wells.
- It is most efficient if first the injection well is drilled and fractured, and afterwards the two production wells are drilled near the borders of the induced fractures.
- The simulations show that it is possible to design a fracture system which leads to a sustainable heat production applicable for oil sands processing in Northern Alberta.

It was shown that a detailed knowledge about the stress state is most important for planning stimulation treatments in Northern Alberta basement rocks. Without a more detailed knowledge about the stress state no particular treatment design can be suggested. Additionally, information about stress state, natural fractures, permeability, porosity and the Young’s modulus have to be collected by surface geophysical methods (seismic, MT), geophysical logs, hydraulic well tests and core measurements for a detailed planning of a stimulation treatment since these parameters showed the highest sensitivities on the fracture geometry within their proposed range. The influence of the treatment parameters on the final fracture properties is high enough that unfavorable reservoir conditions can be handled efficiently by choosing different treatment parameters if the main properties of the reservoir are known in sufficient detail.
Three different treatment concepts were tested. The results of the waterfrac treatments showed that not enough fracture conductivity can be obtained considering only tensile opening of new fractures. Because this kind of treatment has already provided very good results in the geothermal and gas industry, the self-propelling effect of sheared fractures seems to be significant and that is the reason why the fracturing simulator used is not appropriate to model water fracturing treatments. Therefore, future studies will focus on the influence of natural fractures, self-propelling and waterfrac treatments for Precambrian basement rocks in the Athabasca region using a different approach.

Acknowledgements

This study was conducted under the Helmholtz Alberta Initiative (HAI) project. The authors are grateful for the financial support provided from the Alberta Government through this initiative. We thank Mayer & Associates for providing the fracturing software and CMG for providing the reservoir simulator for research purpose.

References


