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Two-dimensional numerical modelling of strategies to avoid thermal stress induced flow channeling in fractured geothermal reservoirs

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Abstract

Thermal drawdown induced flow channeling in fractured geothermal reservoirs has been found to be inevitable in previous work. This hypothesis is questioned and found not to be true for all scenarios. We investigate flow in a simple two-fracture network to investigate the basic behavior of thermal drawdown induced flow pattern changes, using a Thermo-Hydro-Mechanical (THM) numerical model. In addition, we propose two operational interventions to mitigate the negative effects of uneven flow on geothermal production. We found that uneven flow is not inevitable, but dependent on several factors, including initial fracture aperture, the actual value of the aperture, and the total injection rate. A small difference in aperture, a higher aperture value and a larger total injection rate are all factors improving the chances for even flow. The operation interventions include variable injection rates, and sequential injection in the fractures before normal production. Both are shown to improve the chances for even flow and better production. Overall, changes in stress and pressure as a result of cooling, are found to have significant effects on flow pattern and production values, underlining the need for advanced numerical models capable of THM modeling for accurate geothermal production analysis in low permeability fracture networks.

Keywords: Geothermal; Enhanced geothermal systems; Flow channelling; THM model; MDEM; Thermal breakthrough

1. Introduction

Unconventional geothermal resources have the potential to revolutionize the energy landscape, but face several challenges in order to become a serious alternative on a global scale (Tester et al., 2006). Enhanced (or Engineered) Geothermal Systems (EGS) must be stimulated to be economically viable. This can include hydraulic fracturing, or shear stimulation of pre-existing fractures, in order to establish fluid flow pathways in the low permeability rock. The nature of the fracture network should provide sufficient surface area so as to access an adequate volume of hot rock. From a geothermal production standpoint, a large fracture surface area is needed for sustained high temperature fluid production. Due to the poor thermal conductivity of rocks, an even distribution of flow pathways within the rock volume will promote longer field life by delaying thermal breakthrough. This poses several challenges for both stimulating the fracture network and maintaining production flow. Various methods to stimulate low-permeability rock have been trialled but are still insufficient for EGS to present a serious energy alternative (Regenauer-Lieb et al., 2015; Jung, 2013). Jung (2013) carried out a review of previous EGS projects, including the stimulation method used, and concluded that the concept of activating the pre-existing fracture network seemed inadequate. They proposed stimulating multiple parallel wing cracks that connected two wells as a possible way forward. The effect of production related cooling on such crack configurations is the focus of this study.

In a review of previous EGS projects, Grant (2016) found that flow was generally confined to a very small fraction of the stimulated volume. Flow channeling, or uneven flow, refers to the phenomenon where fluids are concentrated in a small portion of the flow network (Fu et al., 2016). In order to optimize stimulation and production methods, and to accurately estimate production outcomes, it is important consider changes in flow patterns. For instance, Fox et al. (2013) studied the recovery times for an EGS with multiple parallel fractures, however, they did not account for thermal stress and aperture changes of the fractures. Vik et al. (2018) investigated the effect of thermoelastic interaction between multiple fractures on production data, but assumed equal flow in all fractures. Using a 3-D model, they were able to investigate the effects of flow channeling within a single fracture, as well as the stress interaction between multiple fractures. However, by assuming a constant injection rate within each fracture, they did not investigate the effects of flow channelling between fractures, i.e., where one fracture takes more fluid because its permeability has increased

relative to the other. Xia et al. (2017) presented finite element simulations of heat production from sets of wing cracks, but assuming a constant permeability in the fractures.

Several 3D thermo-hydro-mechanical (THM) models have been applied to study aperture changes as a result of heat extraction, within a single fracture. Ghassemi and Zhou (2011) used the displacement discontinuity (DD) approach to couple a FEM flow and heat transport model for the fracture through a displacement discontinuity approach to a thermo-poroelastic model for the rock matrix. The planar fracture surface was the only discretized part of their model. They found that the short term behavior in terms of fracture pressure and aperture was controlled by leak-off induced poroelastic effects, while thermoelastic effects controlled the long term behavior. Cooling of the rock mass hence led to an increase in aperture with time. Pandey et al. (2017) confirmed this observation using a 3D FEM where the fracture was mimicked as a thin equivalent porous medium with stress dependent stiffness enabling quantification of the aperture change. The thermal gradient from injector to producer caused fracture opening to decline with distance from the injector, in cases leading to closure near the producer. The authors also pointed to the strong sensitivity of their results to the thermal expansion coefficient, which was substantiated by Salimzadeh et al. (2018a). They suggested to use an effective value for this coefficient in between undrained and drained, to account for the combined effect of thermal (undrained) and poroelastic (drained) response. Salimzadeh et al. (2018b) used a 3D THM FEM model for a single fracture embedded in impermeable and permeable reservoirs. In the latter case they found that the initial fracture aperture had a primary control on cold fluid flow, which may lead nearby fractures to become potential pathways (“flow channeling”). They also showed that stress redistribution reduces the probability for fracture opening but increases the likelihood of triggering shear displacements. Various other studies have been conducted investigating heat extraction with the effect of well placement, number of wells, the long term effect on hydrothermal processes (Chen and Jiang, 2015; Yang and Yeh, 2009; Blöcher et al., 2010; Shaik et al., 2011). The studies referred above properly accounted for permeability changes due to thermal stress but being largely focused on the impact of single fractures, the effects of thermal stress changes on flow pattern between fractures were not addressed.

Flow channeling, or uneven flow, may refer either to variability in fracture permeability in an equilibrium state, or as a process where flow becomes channelized over time, due to for example thermal drawdown induced aperture changes (Fu et al., 2016; Tsang and Neretnieks, 1998). The

poroelastic and thermoelastic response of a single pre-existing fracture to cooling was investigated by Ghassemi et al. (2008). They showed that, as the rock surrounding a fracture cools, compressive stresses around the fracture are reduced, which results in an aperture increase and a change in flow pattern. The flow patterns affect subsequent thermal and poroelastic stresses, hence the problem is tightly coupled.

Fu et al. (2016) observed that flow can become localized in a few channels in a fracture network during heat production as a result of thermal drawdown induced stress changes, and can significantly affect production estimates. Guo et al. (2016) investigated thermal draw down induced uneven flow in a single fracture, and concluded that it was inevitable. In addition, they quantified the effect of thermal stress on uneven flow and on production values. Salimzadeh et al. (2019) found that unfavorable flow pathways due to stress changes can occur during heat extraction. Several other studies have shown that thermal draw down induced stresses can increase injectivity or decrease injection pressure (Koh et al., 2011; Hicks et al., 1996; Grant et al., 2013; Dempsey et al., 2015).

Although uneven flow has been shown to have a significant effect on geothermal production, there is still room to improve our understanding of its basic mechanisms in a fracture network. This includes understanding how many fractures in a network receive flow, their initial conditions, their location and characteristics relative to each other, and the evolution of channelization over time. Comprehension of the underlying physics could help improve EGS production estimates, and provide some insight into how stimulation and production treatments should be optimized.

When cold water is circulated through a fracture network, the fracture receiving the most fluid tends to cool most rapidly. This suggests a self-amplifying phenomenon where the fracture with the largest permeability receives the highest permeability increase as a result of cooling. However, this is a simplistic view of the problem. First, the flow distribution between two pathways of equal pressure gradient is not dependent on the difference between the apertures but rather the ratio. This means that one pathway can have a larger increase in aperture than the other over time, but still receive less and less fluid. It is the aperture increase relative to the initial value that matters. Second, the rate of aperture increase tends to decline over time. The wider aperture may reach a steady-state while the other narrower one continues to increase (and receive more flow) with time. Thus, thermal draw down induced changes in flow patterns may not result in uneven flow for all cases at all times. An observation that may support this hypothesis – a tracer test at Fenton Hill EGS showed that

flow patterns became more diffuse with time, accessing more of the reservoir (Brown, 2009).

The evolution of EGS flow patterns over time is a thermo-hydro-mechanical (THM) problem. Chemical effects have been shown to have an effect on fracture permeability in geothermal reservoirs (Ameli et al., 2014; Taron and Elsworth, 2009; Pandey et al., 2014, 2015; Salimzadeh and Nick, 2019). Mineral precipitation and dissolution can significantly alter permeability, especially close to the injection well and over long periods of time (years) (Taron and Elsworth, 2009). However, these effects are expected to be minor in crystalline formations that are the typical target of EGS projects. Hence, we have excluded chemical effects. Stimulation of new fractures have been shown to occur in EGS projects, and could have an impact on flow pattern changes during heat extraction (McClure and Horne, 2014). The focus of this work is on a simplified set-up in order to investigate the basic mechanisms of flow pattern changes in an understandable manner. Propagation of fractures and activation of natural fractures during production is therefore not included.

In this paper, we use a THM model to investigate flow patterns changes in an EGS type scenario with pre-existing parallel fractures. We focus on the basic processes of uneven flow during production, the rate at which it occurs, and methods to mitigate it and promote more even flow. The model used is a hybrid finite-discrete element rock mechanics model called MDEM (Modified Discrete Element Method) coupled with the fluid flow simulator TOUGH2 (Pruess et al., 1999). A sub-gridscale model has been developed to allow finer scale resolution of thermal gradients in TOUGH2 (Pruess et al., 1999) compared to MDEM. This results in reasonable computational speeds while still capturing detailed temperature and pressure gradients needed to accurately resolve thermal stresses and fluid cooling. It is emphasized that the focus is on basic processes of flow pattern changes during heat extraction, and aims to build confidence with MDEM’s capability to model THM effects. This study does not consider the original formation of the fractures or their extension during production, but this could be included in future work with MDEM.

2. Numerical modeling

The rock mechanical model used in this study is an implementation of the hybrid finite element method/discrete element method (FEM/DEM) called MDEM. MDEM is capable of modeling hydraulic and shear fracture initiation and growth, and is controlled by physical criteria, enabling for

144 non-planar fractures. The 2D version of this code has been coupled to the geothermal reservoir
 145 simulator TOUGH2 (Pruess et al., 1999). The coupling is two-way explicit sequential, and is im-
 146 plemented such that permeability and pressure fields are sent from MDEM to TOUGH2, flow is
 147 calculated and a new pore pressure field is sent back to MDEM. MDEM then solves for displace-
 148 ments and checks for failure, uses this to update the permeability field (see Fig. 1 for an overview of
 149 the coupling) and then hands back to TOUGH2. MDEM uses linear triangular elements, and acts
 150 in FEM mode before failure initiation, whereas failed elements are converted to a cluster of discrete
 151 elements. The frictional failure of an element is based on the Mohr-Coulomb failure criterion. When
 152 the failure criterion is reached, the mechanical behavior and properties of the element are changed
 153 to match that of a fracture. This includes an alteration of the stiffness matrix of the DEM clusters,
 154 resulting in the cluster having no resistance to opening, but resistance to further closure. Based on
 155 the pressure in the failed element and on the local stress state, displacements are calculated, which
 156 are used for fracture aperture calculations. Mass balance is accounted for, and the aperture is then
 157 used to calculate a permeability that can be exported to TOUGH2. There is no direct representation
 158 of the actual fracture in the mesh, and flow is based on the assumption that it is located somewhere
 159 within the failed element. The permeability of the element is therefore modified such that flow
 160 through the element is equivalent to that of a fracture extending through the element of its given
 161 aperture. Porosity and pore pressure of failed elements are altered to conserve mass balance under
 162 aperture changes. For more information on MDEM and its coupling to TOUGH2 see (Rongved et
 163 al., 2019; Lavrov et al., 2014; Alassi et al., 2011).

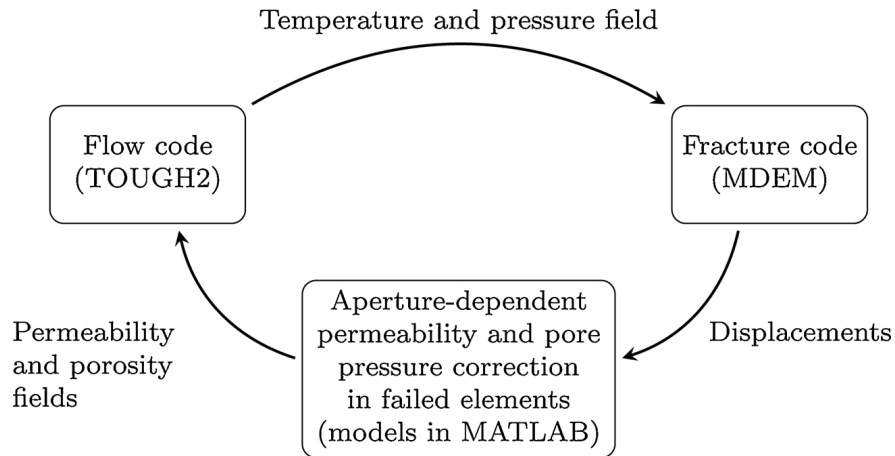


Fig. 1. An overview of the coupling between MDEM and TOUGH2.

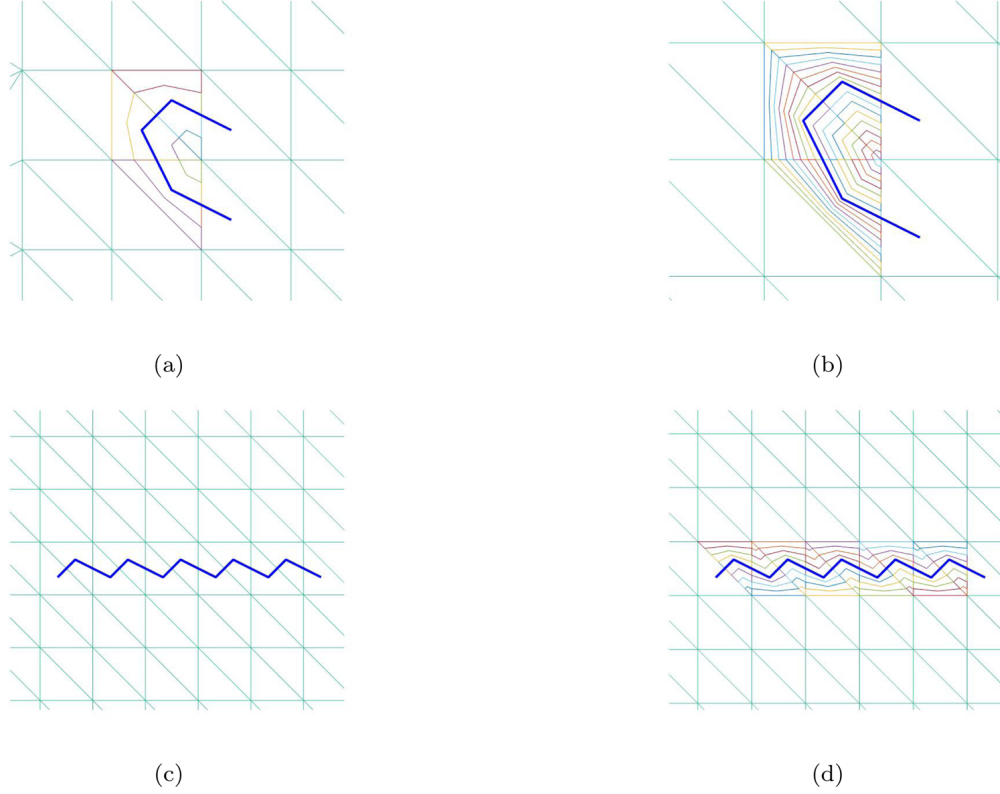


Fig. 2. Illustrations of various sub-grid implementations and resolutions, with a resolution of 4 sub-grid elements in (a) and 16 in (b). Fracture before the sub-grid implementation is illustrated in (c) and (d) shows a the fracture with the sub-grid implementation (colors are for illustration purposes only). (For interpretation of the references to color in this figure legend, the reader is referred to the web version of this article.)

2.1. TOUGH2 and coupling to MDEM

MDEM makes use of irregular triangular meshes. TOUGH2 does not explicitly use the geometric shape of an element, only its volume, and the contact area and centroid to surface distance with an adjoining element. As there is no direct representation of the fracture in MDEM, several assumptions are made regarding fracture surface area and length, based on the size of the failed element.

Modeling of thermal effects in the vicinity of a fracture poses some challenges with the DEM formulation and coupling with TOUGH2. Prior to our modifications, MDEM and TOUGH2 used the same mesh, which means that the TOUGH2 fracture element had the same geometric characteristics as the failed element in MDEM. This has implications on the fracture surface area and fracture volume, both important for detailed modeling of leak-off and heat transfer from the reservoir to the

production fluid. The failed element is large and contains considerable heat and mass. TOUGH2 views it as a single porous and highly permeable block, and distributes flow evenly throughout. This effectively results in an unrealistically high contact surface area relative to its volume, and the heat is quickly drained away. From a modeling perspective, this results in overestimated production fluid temperature at early time. Later, once the failed elements have been cooled to the injectate temperature, the volume of the failed element relative to the contact area with the reservoir is very small. This leads to an underestimate of heat transfer from the reservoir and production fluid temperature. The larger the elements used in the simulations, the larger the difference between the geometric dimensions used by TOUGH2 relative to the actual fracture growing through the element. This increases the size of the errors related to resolution of temperature gradients around fractures and the heat contained within failed elements. Which impacted our ability to compute thermal stresses, aperture changes, and geothermal production. MDEM has been used successfully for modeling a leak-off test in a constant temperature environment, employing a stress dependent fracture permeability which is described in more detail by Lavrov et al. (2016a)

2.2. Sub-grid geometry and connections

Our sub-gridding routine divides an element into several smaller elements (sub-grid elements) once a fracture has completely transected it. The sub-grid elements are finite volume elements, which are the only kind used in TOUGH2. The principal difference are their dimensions and connectivity relative to the fracture, which enable discretization of sharp temperature gradients near the face. A user-defined number of sub-grid elements is chosen, and the sub-elements are constructed on the assumption that the fracture grows between the centroids of adjacent triangular elements (see Fig. 2). While MDEM continues to use the original mesh, TOUGH2 now uses the finer-scale mesh for pressure and temperature calculations. In addition, the fracture can now be directly represented as an element in the TOUGH2 mesh, with a permeability coming from aperture calculations in MDEM. The temperature is exported to MDEM by taking a volume-weighted average of temperatures of all the sub-grid elements. The pressure of the sub-grid fracture element is exported to MDEM as the failed element pressure, as this is the pressure that would be applied to the fracture wall, required by the FEM-DEM code.

2.3. Thermal diffusion and stress

In this work, TOUGH2 calculates both advection and conduction in the porous media (Pruess et al., 1999). The thermal stress is calculated by MDEM and is based on Timoshenko and Goodier (1970). MDEM is based on explicit finite-element method (FEM), where thermal strains are accounted for in the load vector. The principle of virtual work in the Galerkin formulation of two-dimensional thermoelasticity reads as follows:

$$\int_A \mathbf{B}^T \boldsymbol{\sigma} dA = \oint_L \mathbf{N}^T \mathbf{t} dL + \int_A \mathbf{N}^T \mathbf{b} dA \quad (1)$$

where A is the domain occupied by the body; L is the boundary of the domain; $\mathbf{t}$ is the traction vector; $\mathbf{b}$ is the body force vector; $\mathbf{N}$ is the shape function matrix; $\mathbf{B}$ is the gradient of $\mathbf{N}$; $\boldsymbol{\sigma}$ is the stress column-matrix. In thermoelasticity, the stress column-matrix is given by:

$$\boldsymbol{\sigma} = \mathbf{D}\boldsymbol{\varepsilon} - \mathbf{D}\boldsymbol{\varepsilon}_0 \quad (2)$$

with $\boldsymbol{\sigma} = [\sigma_{xx}, \sigma_{yy}, \sigma_{xy}]^T$, $\boldsymbol{\varepsilon} = [\varepsilon_{xx}, \varepsilon_{yy}, \varepsilon_{xy}]^T$. In Eq. (2), $\mathbf{D}$ is the stiffness matrix and $\boldsymbol{\varepsilon}_0$ is the thermal strain column-matrix. From Eq. (1) and (2) we get the thermal strain contribution to the body force vector given by:

$$\mathbf{f}_0 = \int_A \mathbf{B}^T \mathbf{D} \boldsymbol{\varepsilon}_0 dA \quad (3)$$

A linear triangular element is used in MDEM, and for this type of element the gradient of the element shape function matrix $\mathbf{B}^e$, is given by

$$\mathbf{B}^e = \frac{1}{2A} \begin{bmatrix} y_j - y_k & 0 & x_k - x_j \\ 0 & x_k - x_j & y_j - y_k \\ y_k - y_i & 0 & x_i - x_k \\ 0 & x_i - x_k & y_k - y_i \\ y_i - y_j & 0 & x_j - x_i \\ 0 & x_j - x_i & y_i - y_j \end{bmatrix} \quad (4)$$

216 In Eq. (4), it is assumed that numbering of nodes i, j, k is counter-clockwise. A is the element
 217 area and x, y are coordinates of the nodes. Plane strain is assumed in this study, and $\mathbf{D}$ therefore
 218 becomes

$$\mathbf{D} = \frac{E}{(1+v)(1-2v)} \begin{bmatrix} 1-v & v & 0 \\ v & 1-v & y_j - y_k \\ y_k - y_i & 0 & 0 \\ 0 & 0 & \frac{1}{2}(1-2v) \end{bmatrix} \quad (5)$$

219

$$\boldsymbol{\varepsilon}_0 = \alpha_T(1+v)\Delta T \begin{bmatrix} 1 \\ 1 \\ 0 \end{bmatrix} \quad (6)$$

220 where E is the Young's modulus, v is Poisson's ratio, α_T is thermal expansion coefficient, and ΔT
 221 is the change in temperature.

222 Hence, Eq. (3) yields the following thermal element force vector in plain strain:

$$\mathbf{f}_0 = \frac{\alpha_T E \Delta T}{2(1-2v)} \begin{bmatrix} y_i - y_k \\ x_k - x_j \\ y_k - y_i \\ x_i - x_k \\ y_i - y_j \\ x_j - x_i \end{bmatrix} \quad (7)$$

223 The column matrix given by Eq. (7) reads as follows:

224 –Entries 1 and 2 yield the x - and y - component of the nodal force at node i, respectively.

225 –Entries 3 and 4 yield the x - and y - component of the nodal force at node j, respectively.

226 –Entries 5 and 6 yield the x - and y - component of the nodal force at node k, respectively.

227 **2.4. Aperture change due to temperature change in failed elements**

228 In MDEM, the aperture of a failed element is based on node displacement or change in element
 229 area. An increase in area leads to increased aperture, and vice versa. The aperture is dependent
 230 on the element fluid pressure, and on the compressive stresses acting on it. If the pressure exceeds

the stresses, the element expands, and the aperture increases. If the pressure is lowered below the stresses or the stress increases, it contracts, and the aperture decreases.

A challenge when modeling thermal stresses with the DEM formulation in MDEM is how variations in temperature affect aperture changes of failed elements. The fracture is located somewhere within the failed element, which means that cooling of the failed element should result in contraction of the matrix on either side of the fracture plane, and an increase of the aperture. However, when the fracture is not explicitly represented, the contraction is applied to the entire failed element, resulting in an aperture decrease. We avoid this issue by, for the failed elements, neglecting the force vectors that would otherwise be added due to internal temperature changes. Instead, we separately calculate an area change based on the temperature change gathered from the sub-grid elements of the TOUGH2 model. This area change is then added to the aperture of the failed element.

The aperture of a failed element then becomes

$$\omega = \omega_n + \omega_s + \omega_t + \omega_0 \quad (8)$$

where ω is the total aperture, ω_n is the aperture due to normal displacement, ω_s is the aperture due to shear displacement, ω_t is the aperture due to temperature change of the failed element, and ω_0 is the initial aperture. MDEM calculates the aperture based on the pre-existing aperture (if present), tensile opening due to mode I displacement caused by stresses acting normal to the fracture face, and shear dilatancy induced fracture opening. (Lavrov et al., 2014, 2016b). A benchmark of MDEM against an analytical Khristianovic-Geertsma-de Klerk model can be found in Rongved et al. (2019).

2.5. Model validation

Our improved ability to resolve near-fracture heat conduction and thermal stresses is validated by comparing our simulations to analytical solutions.

2.5.1. Validation of heat conduction

Resolution of near-fracture temperature gradients due to matrix heat conduction is tested using an analytical solution for the linear flow of heat in a solid between two parallel planes as given by Carslaw and Jaeger (1959). The case examined is the solution for a solid of region $0 < x < L$

256 between two parallel planes kept at constant temperatures T_1 and T_2 respectively. The solid has an
 257 initial temperature $f(x) = t_2$. The solution for the temperature at x for a time t is given as:

$$\begin{aligned}
 T(x) = T_1 + (T_2 - T_1) \frac{x}{L} + \frac{2}{\pi} \sum_{n=1}^{\infty} \frac{T_2 \cos n\pi - T_1}{n} \sin \frac{n\pi x}{L} \exp \frac{-\kappa n^2 \pi^2 t}{L^2} \\
 + \frac{2}{L} \sum_{n=1}^{\infty} \sin \frac{n\pi x}{L} \exp \frac{-\kappa n^2 \pi^2 t}{L^2} \int_0^L f(x') \sin \frac{n\pi x'}{L} dx'
 \end{aligned}
 \tag{9}$$

258 Where $\kappa = \frac{K}{\rho c}$ is the thermal diffusivity, K is the thermal conductivity, c is the specific heat, and ρ
 259 is the density of the solid.

260 A numerical representation of the problem was constructed by creating two elements representing
 261 the parallel plates with a third element representing the solid between them. An illustration of the
 262 setup, with an example of 9 sub-grid elements can be seen in Fig. 3. The distance, L , between the
 263 center of the two constant temperature plates is 4.7 m, and the solid between the plates (in orange)
 264 is 2.4 m which is divided in a predefined number of sub-grid elements with equal thickness. The
 265 contact surfaces between adjacent sub-grid elements are set equal to be comparable to the analytical
 266 solution, although this would not generally be the case for triangular elements. The two elements
 267 representing the plates from the analytical solution are set at constant temperatures 22° (plate 1)
 268 and 40° (plate 2) at each side of the solid. The sub-grid elements (orange) are given an initial
 269 temperature of 40° . Fig. 4 shows dividing the middle element into 9 sub-grid elements give a good
 270 fit to the analytical solution. This shows that TOUGH2 is able to model the heat flow and capture
 271 the temperature gradient at this mesh resolution.

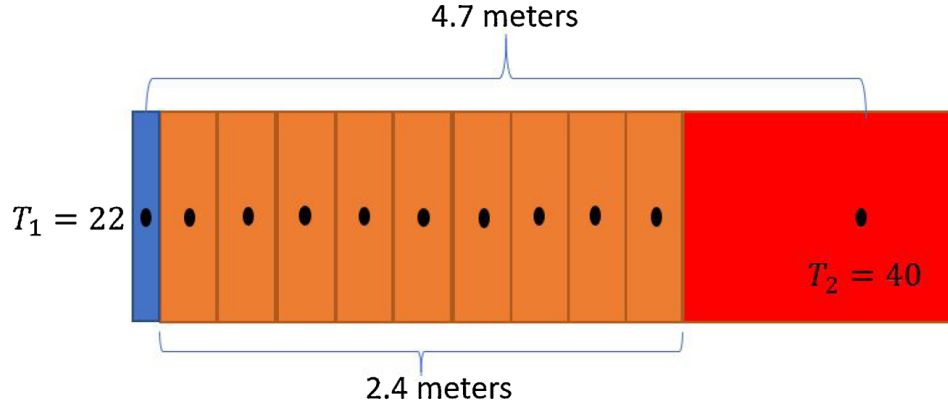


Fig. 3. Visualization of the mesh used for the heat flow simulations as seen in Fig. 4. The blue element (to the left) holds a constant temperature of 22° and the red element (to the right) holds a constant temperature of 40° . The orange elements are the sub-grid elements, and have an initial temperature of 40° . (For interpretation of the references to color in this figure legend, the reader is referred to the web version of this article.)

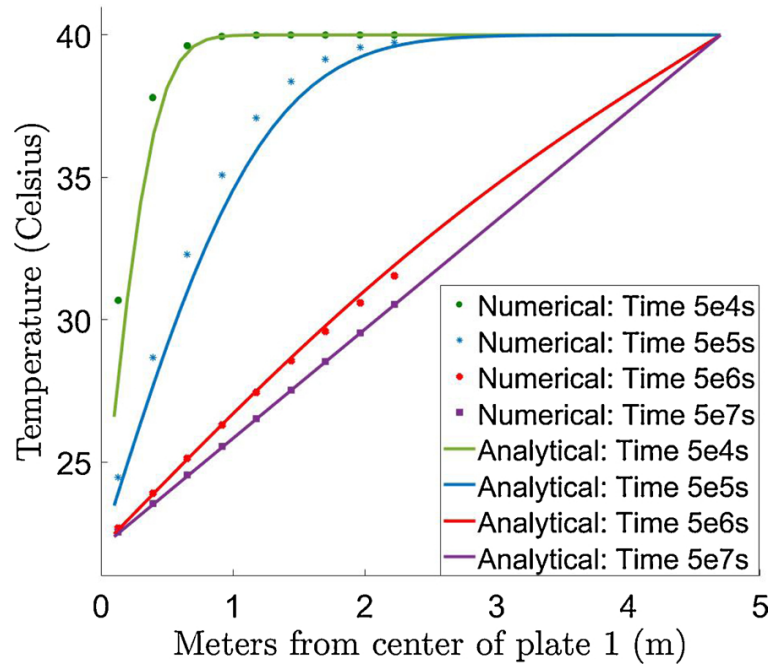


Fig. 4. Comparison between analytical solution (solid line) and simulation (dots) of heat flow using 9 sub-grid resolutions.

2.5.2. Validation of thermal stress

Thermal stress calculations in MDEM are validated by numerically modeling the stresses induced by cooling of a circular inclusion, and comparing this to the available thick-bed solution presented in Perkins et al. (1984).

The model setup is given in Fig. 5a, where a circular inclusion is uniformly cooled to a temperature of 10° , from an initial reservoir temperature of 100° . The maximum principle internal stress in the inclusion is given by

$$\Delta\sigma_{\text{Hi}} = \frac{E\alpha_T\Delta T}{(1-\nu)},$$

where E is Young's Modulus, ν the Poisson's ratio, α_T is the linear coefficient of thermal expansion, and ΔT is temperature change, in this case -90° . Internal and external to the inclusion are represented by i and e as subscripts respectively.

The radial stress external to the inclusion is

$$\Delta\sigma_{\text{re}} = \Delta\sigma_{\text{Hi}}(r_a/r)^2,$$

where r_a is the radius of the inclusion and r is the radius from the center. The tangential stress external to the inclusion is

$$\Delta\sigma_{\theta\text{e}} = -\Delta\sigma_{\text{Hi}}(r_a/r)^2.$$

For more information and complete derivation of equations see Perkins et al. (1984).

As can be seen in Fig. 5b, there is a good fit between numerical results and the analytical solution. The slight oscillation in the numerical results is due to the center of the triangular elements slightly oscillating across the x -axis. The mesh used consist of 75704 triangular elements.

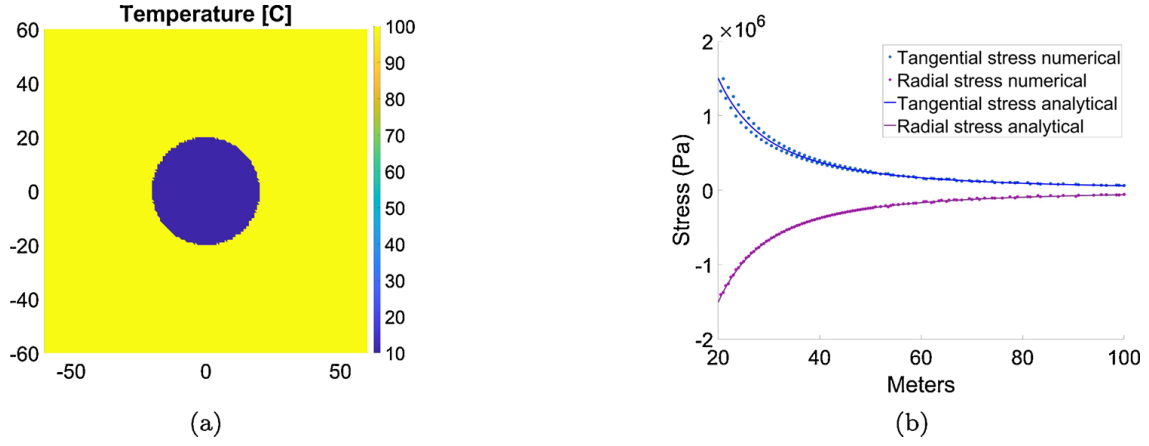


Fig. 5. (a) Final temperature of the cooled inclusion (from 100° to 10°). (b) Comparison of analytical solution (lines) and numerical results (dots).

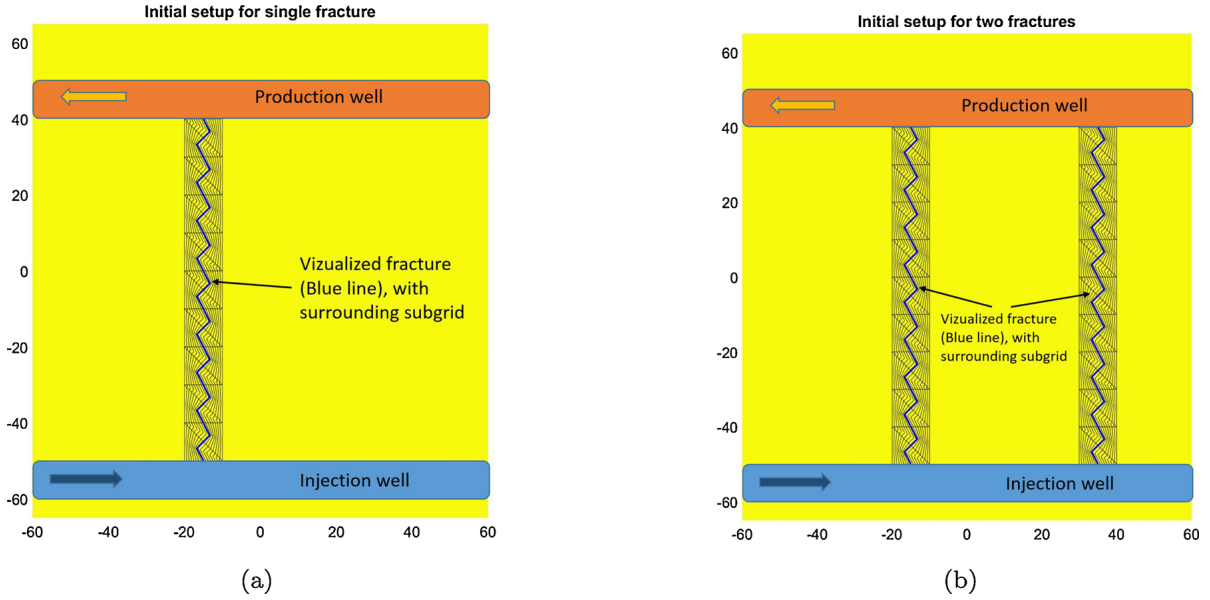


Fig. 6. Scenario configuration for the (a) the single fracture test, and (b) two parallel fractures. With the x - and y -axis, being the horizontal (at $y = 0$) and vertical (at $x = 0$) axes, respectively.

Table 1

Input granite material properties based on previous EGS projects (Björnbsson and Bodvarsson, 1990) and production parameters (standard water properties as used in TOUGH2).

Property	Value
Young's modulus (GPa)	30
Poisson's ratio (in 2D)	0.15
Tensile Strength (MPa)	infinite
Cohesion (MPa)	infinite
Density (kg/m ³)	2700
Porosity (%)	2
Permeability (m ²)	10 ⁻¹⁸
Initial Stresses (σ_x and σ_y (MPa))	30 and 35
Initial pore pressure (MPa)	20
Initial reservoir temperature (C)	150
Initial fracture permeabilities (m ²)	10 ⁻⁹ , $1.5 \cdot 10^{-10}$ or 10 ⁻¹¹
Injection fluid	Water
Injection fluid temperature (C)	2
Injection rate per unit height (m ² /s)	10 ⁻³ , 10 ⁻⁴ or 10 ⁻⁵

2.6. Numerical setup

To study the effects of fracture and flow behavior during production in an EGS scenario, two general set-ups are used (see Fig. 6). An injection well and a production well are connected by either one or two parallel fractures. Selected material properties are listed in Table 1, and the different cases simulated are given in Table 2. A constant injection rate (given as the rate per unit out-of-plane distance) is used for all cases except one (case 8), and a fixed pressure sink is used for production. The wells consist of elements of very high permeability, resulting in a vanishing pressure gradient within each well. The wells have no flow connections to the reservoir except to the failed elements. This is to minimize well effects, and focus on fracture behavior. The distance between the wells is 90 m and, for the two fracture scenario, there is 40 m between the fractures. The fractures are

predefined, and no failure during production is allowed (the fractures are assigned infinite strength).
The fracture geometry is created on the basis that it grows from element center to center. Since the
mesh consist of triangles organized in a regular manner, the fracture does not grow in a straight line

3. Results and discussion

In this section the effect of production on flow patterns in a simplified EGS set-up is investigated.
The main objectives are to look at governing processes and factors of flow channelling, how they
affect production values, and propose operational interventions to minimize flow channelling.

Table 2

Overview of the different cases.

Case number	Number of fractures	Additional info/case focus	Injection rate	Initial fracture permeability
Case 1	Single fracture	The only case with no sub-grid	$10^{-4} \text{ m}^2/\text{s}$	$1.0 \times 10^{-9} \text{ m}^2$
Case 2	Single fracture	Effect of sub-grid	$10^{-4} \text{ m}^2/\text{s}$	$1.0 \times 10^{-9} \text{ m}^2$
Case 3	Two fractures	Effect of fracture permeability	$10^{-4} \text{ m}^2/\text{s}$	$5 \times 10^{-10} \text{ m}^2$
Case 4	Two fractures	Effect of fracture permeability	$10^{-4} \text{ m}^2/\text{s}$	$1.5 \times 10^{-10} \text{ m}^2$
Case 5	Two fractures	Effect of fracture permeability	$10^{-4} \text{ m}^2/\text{s}$	$1.0 \times 10^{-11} \text{ m}^2$
Case 6	Two fractures	Effect of injection rate: Low	$10^{-5} \text{ m}^2/\text{s}$	$1.5 \times 10^{-10} \text{ m}^2$
Case 7	Two fractures	Effect of injection rate: High	$10^{-3} \text{ m}^2/\text{s}$	$1.5 \times 10^{-10} \text{ m}^2$
Case 8	Two fractures	Variable rate	10^{-3} and $10^{-5} \text{ m}^2/\text{s}$	$5.0 \times 10^{-10} \text{ m}^2$
Case 9	Two fractures	Sequential injection	$10^{-4} \text{ m}^2/\text{s}$	$1.0 \times 10^{-11} \text{ m}^2$

3.1. Single fracture: aperture change due to cooling and the effect of sub-gridding (Case 1 and 2)

We first investigate the response of a single fracture to production related cooling to understand its basic behavior and to illustrate the improvement in accuracy due to use of a sub-grid. The effect of sub-gridding on simulated production fluid temperature can be appreciated by comparing cases 1 (no sub-grid) and 2 (sub-grid with varying levels of refinement, Fig. 7). Without the sub-grid, heat contained in the failed elements is rapidly extracted, resulting in a sustained period of high initial production temperatures. Once the failed elements have been cooled, the production fluid temperature drops drastically. In contrast, when flow is simulated using a sub-grid, the production fluid temperature starts dropping almost immediately, and this effect is captured for even relatively coarse resolution. Thus, the principle effect of using a sub-grid gives an improved estimate of when thermal breakthrough occurs in these systems.

An overview of the temperature distribution after one year of flow for the two cases can be seen in Fig. 8. The principal differences are in the temperatures of the failed element, and the position of the cooling front, which has traveled further from the fracture for the simulation without a sub-grid. These differences are significant and impact the estimated thermal stresses, the cooling-related aperture changes, and the production temperature. The effect of dividing an element up in an increasing number of sub-grid elements is shown in Fig. 9. It can be seen that with more than 6 subgrid elements the effect of increasing the number of subgrids flattens out (Fig. 9). Although a sub-grid with 8 elements appears sufficient to capture thermal breakthrough (Fig. 7), for the remaining simulations in this study, we use a sub-grid with 16 elements.

As the temperature in the matrix decreases, both the pore fluid and matrix contract. The difference in thermal contraction between the two is such that a fluid underpressure develops in these blocks. This cooling leads to significant stresses developing around a single fracture as can be seen for the normal (x -)stress in Fig. 10a, and shear (xy -)stress in Fig. 10b, both after one year of production. Fig. 10c shows the pressure distribution around the single fracture (case 2) after one year of production. The region of pressure decrease extends beyond the cooled zone. This indicates that the low pressure in the cooled zone creates an influx from the surrounding rock of higher pressure, i.e., the region of low pressure migrates further from the fracture. This decrease in fluid pressure will

335 also tend to increase effective normal stresses and may inhibit further fracturing (see Fig. 11a and b
 336 for temperature and stress distribution, respectively, at various time during production). As was seen
 337 above, significant shear stresses evolve and may lead to shear displacement or shear fracturing, in
 338 agreement with Salimzadeh et al. (2018a). Fig. 11c, shows the pressure along the x -axis for various
 339 times. As can be seen, the pressure is higher than in the surroundings close to the fracture due to
 340 leak-off. This increase will tend to reduce the aperture, but will be small compared to thermo-elastic
 341 effects in low permeability rocks (Ghassemi et al., 2008). The matrix permeability used in these
 342 simulations are quite low (10^{-18} m²), and poro-elastic effects related to leak-off within the sub-grid
 343 elements are ignored for this study. Poro-elastic effects outside the subgrid elements are accounted
 344 for, but are negligible because of the low permeability. See Fig. 11b, for the effective stresses normal
 345 to the fracture for various times at a distance normal from the middle of the fracture.

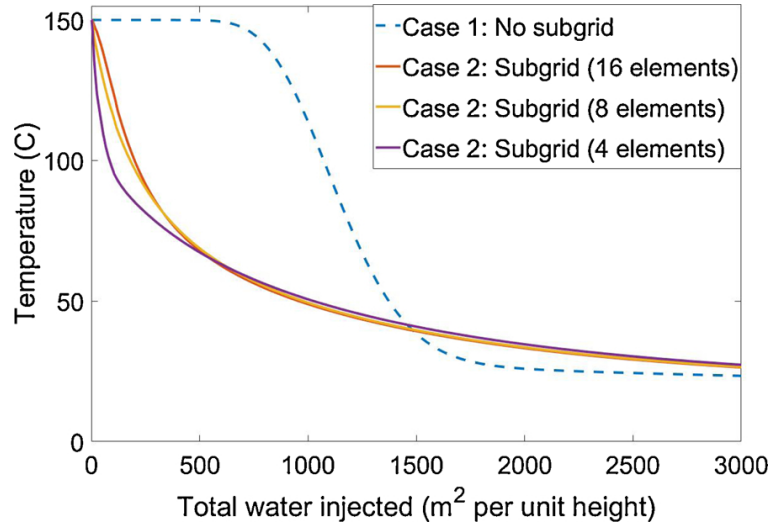


Fig. 7. Temperature of production fluid for case 1 (blue, no sub-grid) and 2 (yellow, orange and purple, varying sub-grid resolutions). (For interpretation of the references to color in this figure legend, the reader is referred to the web version of this article.)

346 **3.2. Two fracture system: thermal drawdown induced changes in flow pattern**

347 In this section, we investigate the effect of cooling on flow pattern changes through a simple case
 348 with two-fractures connecting two wells (see Fig. 6b). This is to compare effects of different factors
 349 on production values in a simple way, and to allow for a simple investigation of increased recovery
 350 techniques.

3.2.1. Flow distribution between two fractures and thermal drawdown induced flow pattern changes

Thermal draw-down induced changes in flow pattern are not found necessarily to result in uneven flow for all cases. This can be illustrated by an analytical simplification. Flow between two parallel plates is given by

$$Q = \frac{\Delta P \omega^3}{12\mu}, \quad (10)$$

where Q is the flow rate, ΔP is the pressure difference, ω is the aperture and μ is the viscosity. By assuming equal pressure gradient for the two fractures the flow for the individual fractures (fracture A and B) can be found by

$$Q_A = Q \frac{1}{1 + (\omega_B/\omega_A)^3}, \quad \text{given } Q = Q_A + Q_B. \quad (11)$$

Eq. (11) simplifies the problem through an assumption of flow between parallel plates based on the fracture's average aperture, but it is clear that the ratio between the apertures govern flow distribution in this simplified setup. For flow distribution to change in favor of one fracture over the other, the ratio between them has to change. For uneven flow to occur is not enough that the difference $\omega_{max} - \omega_{min}$ between the apertures increases, but the ratio $\frac{\omega_{min}}{\omega_{max}}$ has to decrease (where ω_{max} is the fracture with larger aperture between two competing fractures, and ω_{min} is the fracture with a smaller aperture). Therefore the following conditions can be defined for this two fracture system:

$$\frac{\partial \frac{\omega_{min}}{\omega_{max}}}{\partial t} < 0 \quad \rightarrow \quad \text{Uneven flow} \quad (12)$$

$$\frac{\partial \frac{\omega_{min}}{\omega_{max}}}{\partial t} > 0 \quad \rightarrow \quad \text{Even flow} \quad (13)$$

For a ratio to change in favor of one fracture over a given time, it must have a higher percentage wise increase than its neighbor. This can be illustrated by defining an aperture multiplier representing the growth factor for the aperture over a given time step. If a given time step is defined by $\Delta t = t_{n+1} - t_n$, the change in aperture over that time step can be written as $\Delta\omega = \omega_{n+1} - \omega_n$. An aperture multiplier γ can then be included through the relation as follows:

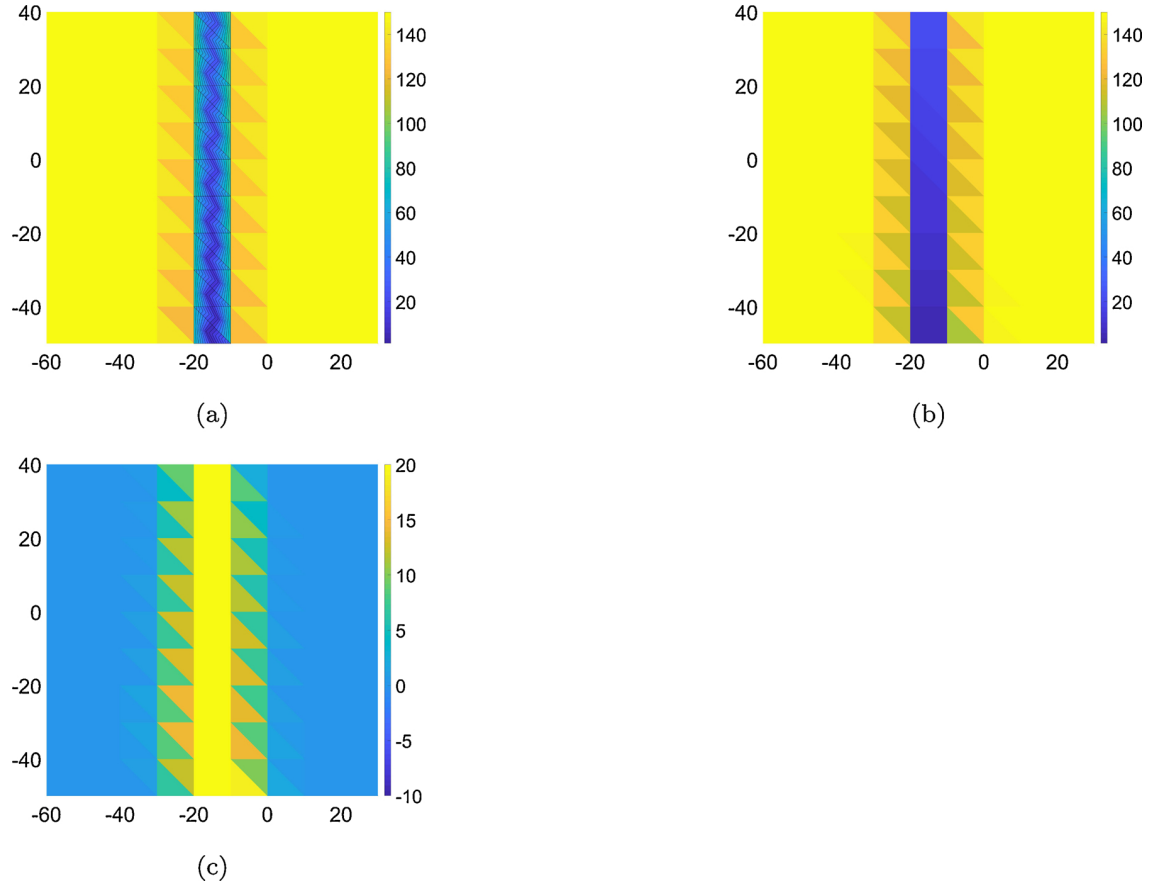


Fig. 8. Temperature profile after one year of production for: (a) case 2 (with sub-grid using 16 elements) and (b) case 1 (no sub-grid). (c) Temperature difference between (a) and (b).

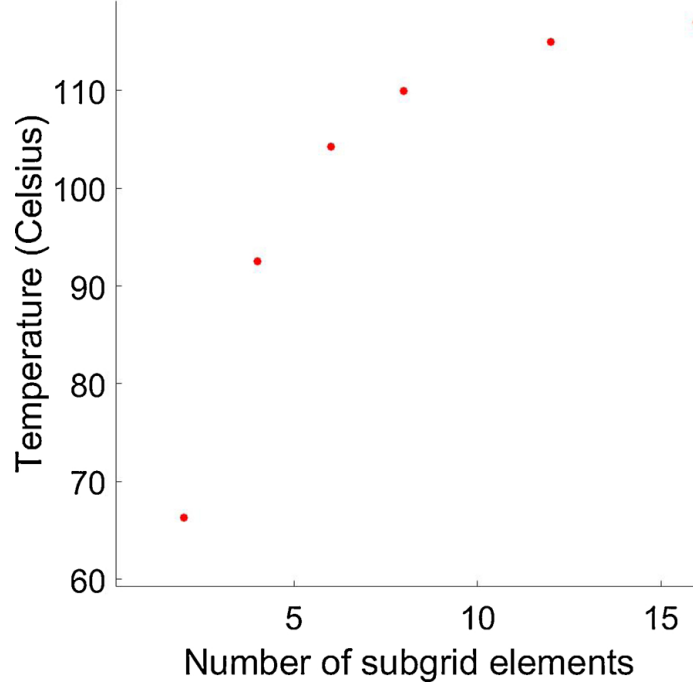


Fig. 9. Shows the production fluid temperature after 16 days, with varying number of sub-grid elements.

$$\omega_{n+1} = \gamma_n \cdot \omega_n \quad (14)$$

373 The change in aperture ratio over a given time step then becomes,

$$\Delta \frac{\omega_{\min}}{\omega_{\max}} = \frac{\gamma_{\min,n} \cdot \omega_{\min,n}}{\gamma_{\max,n} \cdot \omega_{\max,n}} - \frac{\omega_{\min,n}}{\omega_{\max,n}} \quad (15)$$

374 The condition in Eqs. (12) and (13) for a given time step can then be written as

$$\gamma_{\max} - \gamma_{\min} > 0 \quad \rightarrow \quad \text{Uneven flow} \quad (16)$$

375

$$\gamma_{\max} - \gamma_{\min} < 0 \quad \rightarrow \quad \text{Even flow} \quad (17)$$

376 Therefore, if the aperture multiplier of the narrower fracture over a given time step is larger than
 377 that of the wider fracture, flow will even out and vice versa.

3.2.2. Effect of initial aperture

Three cases are presented that vary the initial fracture permeabilities (Table 2). The fractures have an initial hydraulic aperture, where the aperture is equal to $\omega = (k_f \cdot 12)^{\frac{1}{2}}$ where k_f is the initial permeability of the fractures, but are mechanically closed. This means that the fractures will have to overcome the minimum principal stress to open further. The fractures have the same initial conditions but, due to irregularities in the mesh (approximating variability in natural systems), one fracture will receive slightly more flow than the other. In addition, the two fractures slightly interact through some stress shadowing, adding some variability, especially in the high flow rate case (case 7) where the fracture pressure is higher (Fisher et al., 2004).

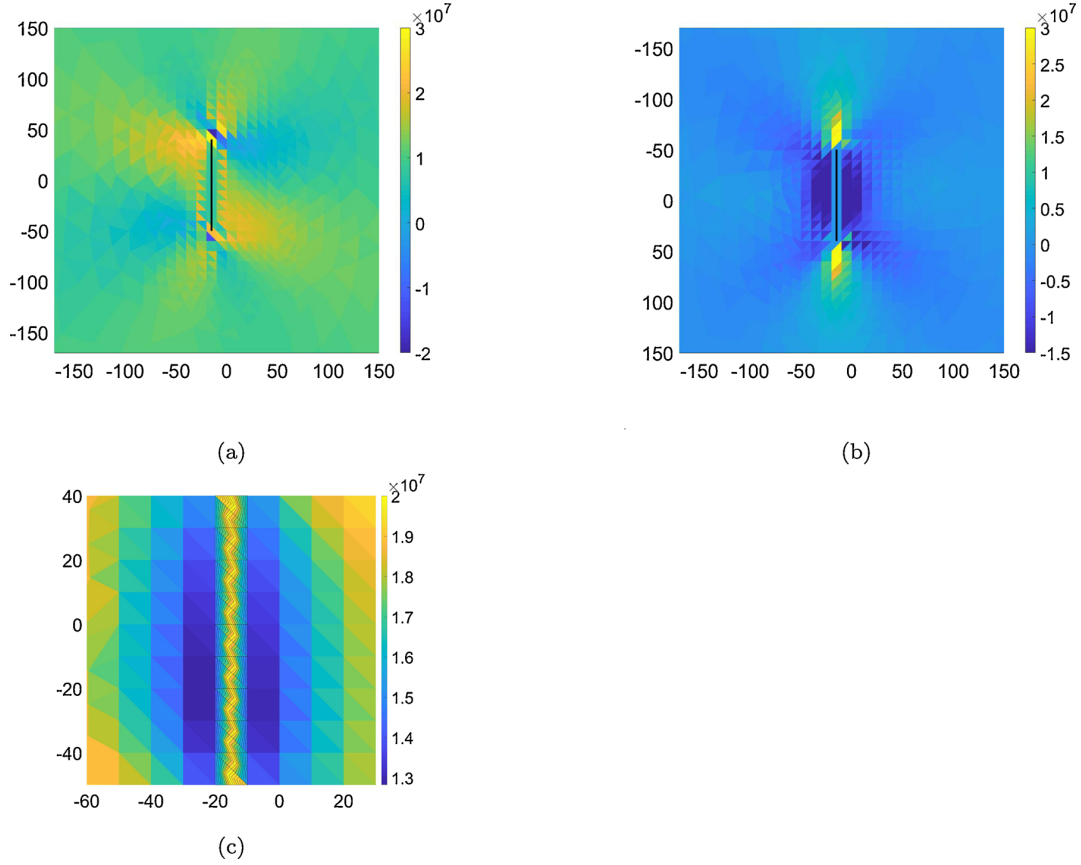


Fig. 10. Case 2 (with sub-grid): (a) Effective stress in x -direction after one year of production. (b) Effective stress in xy -direction after one year of production. (c) Pressure profile after one year of production.

A larger difference in aperture will result in a larger difference in flow distribution and the actual values of the apertures will affect how the flow pattern develops over time. Since the change in

aperture due to cooling is independent of the initial aperture (except to the extent that it governs initial flow distribution), the initial value will affect how the ratio between the apertures develop over time during production. For larger initial apertures, there will be a smaller percentage wise aperture increase due to cooling.

Case 3 is the case with highest initial fracture permeability of $5 \times 10^{-10} \text{ m}^2$, where both fractures are initially sufficiently open to facilitate significant flow. As can be seen in Fig. 12a and b, these conditions cause relatively even flow from the beginning, resulting in close to equal aperture increase for both fractures, and even cooling of the reservoir.

The temperature field after one year production and aperture development of case 4 (initial permeability of $1.5 \times 10^{-10} \text{ m}^2$) can be seen in Fig. 12c and d respectively. With a lower initial aperture, this case experiences some initial uneven flow with varying increase in aperture between the fractures. But the flow pattern changes and, after some time, the difference in apertures evens out and flow evens out.

Case 5 has a low initial permeability of 10^{-11} m^2 . As a result of this low permeability, the fractures must open significantly to accommodate the injection rate under a given stress state. In the beginning, the fractures compete for fluid. Eventually, one fracture receives more fluid and cools more than the other, increasing its aperture. After a couple of days, this fracture receives most of the flow. Fig. 12e shows that the rock surrounding the fracture to the right has been cooled, whereas the temperature around other fracture is largely undisturbed. The temperature of the production fluid drops quicker compared to the base case, indicating a significant reduction in energy production as a result of uneven flow (Fig. 13). Fig. 14 shows the flow distribution as a function total water injected for case 3, 4 and 5. As can be seen, case 3 has little variation in flow distribution with close to equal flow, case 4 goes from initial uneven flow to more even flow, ending up with close to equal flow after some time, and case 5 experiences strong initial uneven flow that dominates the remainder of the simulation.

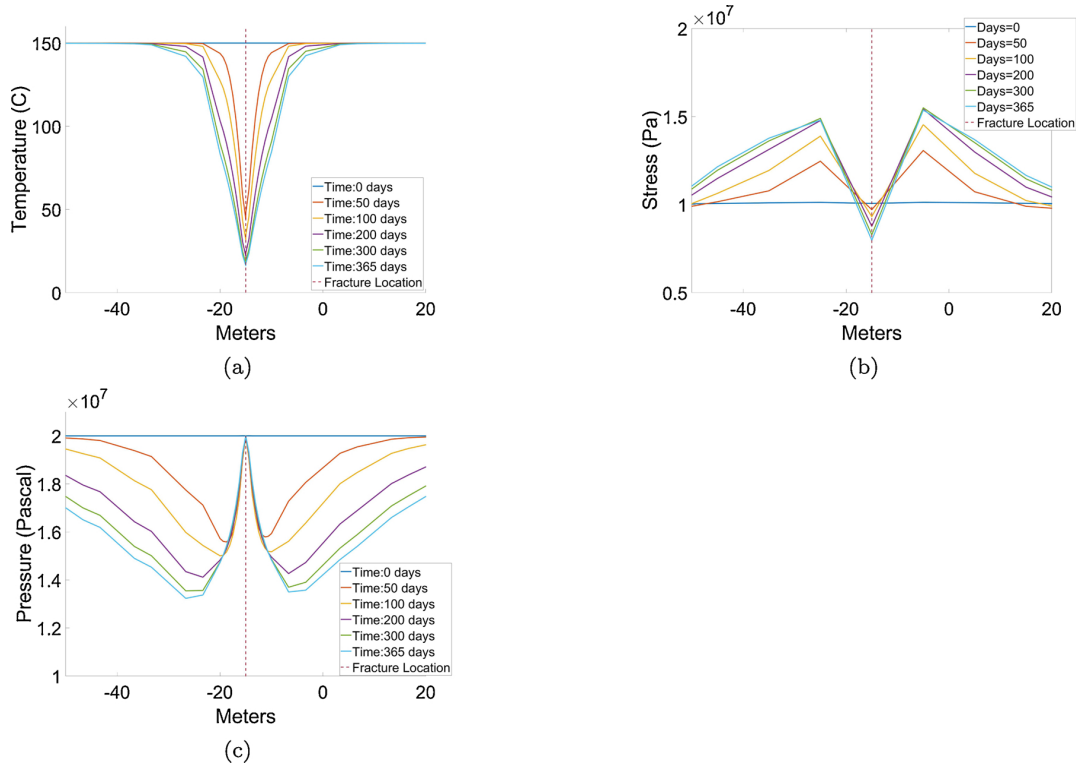


Fig. 11. Case 2 (with sub-grid): (a) Temperature, (b) effective compressive stress and (c) pressure along the x -axis (as described in Fig. 6) at different times during production. Stippled line represents the fracture position.

These results indicate that the initial apertures are of importance in the changes in flow patterns during heat production. Higher initial apertures and smaller differences between them are beneficial for the flow to even out over time, and smaller initial apertures with greater difference between them result in uneven flow. In addition, it is shown that uneven flow can occur initially, but that the flow can even out over time, dependent on initial conditions. Because we have only simulated two parallel fractures in an idealized reservoir, we must be cautious in extrapolating to EGS through a complex fracture network. However, we suggest that as more fractures are added to a network, permeability homogeneity becomes increasingly unlikely, and the likelihood of flow channeling could increase.

3.2.3. Effect of total flow rate

Change in total flow rate can have significant impacts on flow pattern changes over time. By increasing the total flow the aperture increases quicker for both fractures, but this change may be

uneven. Fig. 15 shows the aperture increase as a function of flow rate for the given reservoir after 50 days of production. As can be seen, aperture increase as a function of rate is not linear, which means that the narrower fracture can experience a larger percentage wise aperture increase than the wider one, with for example, a doubling of rate for a given time. If this is the case, it will improve the chances of even flow.

At low rates where the flow is not enough to cause significant cooling, the impact of a flow rate increase on the aperture will be small. For high rates, where there is already enough flow to keep a low temperature throughout the fracture, the effect of flow increase is also not as significant. In between these low and high rates, the effect of flow rate change is large. This indicates that, depending on the pre-existing flow rate distribution, an increase in total flow rate can be used to improve chances for even flow. It is beneficial that the wider fracture already receives high enough flow rate to cool significantly, and that the narrower fracture is in, or close to the region where an increase in flow has a large impact on aperture increase.

Case 4, which led to even flow over time, and quite even cooling of the reservoir at a flow rate of $10^{-4} \text{ m}^2/\text{s}$, was re-run with a lower total rate of $10^{-5} \text{ m}^2/\text{s}$ (case 6) and with a higher total rate of $10^{-3} \text{ m}^2/\text{s}$ (case 7). As can be seen in Fig. 16, the lower rate of case 6 resulted in uneven flow and uneven cooling of the reservoir, indicating poor production. While the higher rate of case 7 resulted in even flow after some slight initial uneven flow, with even cooling of the reservoir, indicating good production. Fig. 17 shows the flow distribution over total water injected for case 4, 6 and 7. Case 4 (medium total flow rate) has close to equal flow, case 6 (low total flow rate) experiences strong initial uneven flow and close to all flow quickly goes through one of the fractures, and case 7 (high total flow rate) experience initial uneven flow, but flow evens out over time, and close to equal flow is obtained after some time. For case 7, the higher rate results in a fracture pressure increase, and therefore a stronger stress shadow cast from the fractures. This interaction leads to initial uneven flow in fracture 1. As can be seen in Fig. 18, case 7 has a higher well pressure than case 6, which again leads to a slight difference in fracture pressure between the two cases. The fracture pressure affects the stress shadow and therefore the interaction between the fractures. The difference in compressive stress normal to the fracture before significant cooling occurs (only pressurized fractures) between case 6 and 7 can be seen in Fig. 19. This difference is, however, small, and as the well pressure drops the stress shadow exerted by the fractures decreases. This implies that stress shadowing has some

initial effect at high injection rates, affecting initial fracture interaction and flow distribution, but has little effect after some time as the fracture pressure drops.

Case 7 also experience a lower aperture increase per volume injected, as the higher injection rate results in a higher velocity of the fluid through the fracture, which reduces the time for heat exchange. This effect can also be seen in Fig. 20, which shows the total stress (normal to the fracture) over time in the middle between the fractures, where case 7 experience a much smaller decrease in total stress per unit of water injected. The total stress decreases as a result of pore pressure decrease from a decreasing temperature in the rock matrix. With a lower injection rate, there is a greater heat exchange per unit of injected water, and therefore the total stress decrease more per unit of injected water with a lower injection rate. These results show that the total flow rate affects thermal draw-down induced changes in flow pattern and higher flow rates improve chances for even flow and even flow over time.

3.3. Operational mitigation techniques against uneven flow

In this section, we address the negative impact of uneven flow on geothermal production by proposing alternative stimulation techniques aimed at increasing recovery. As shown in the previous section, an increase in fracture permeability/aperture decreases the chance of uneven flow and its negative impact on heat production. A higher flow rate can be used to operationally mitigate the negative effects of uneven flow on production. This indicates that methods to increase the apertures of the fractures before starting normal production can improve the chances of more even flow. Two methods are proposed, focused on increasing the aperture of both fractures before normal production, involving variable flow rates, and sequential injection.

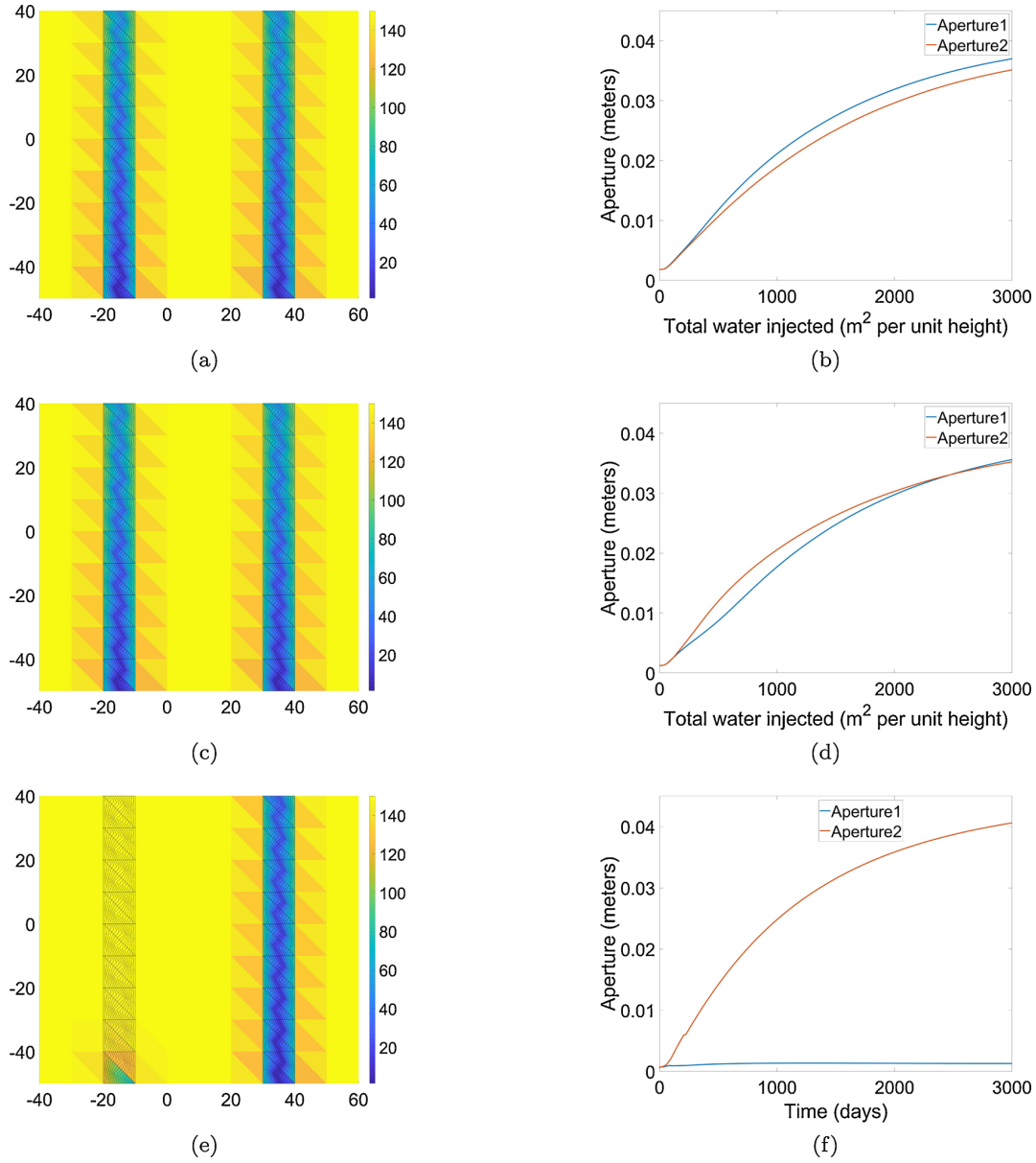


Fig. 12. The temperature field after a year of production and average aperture over total water injected for: Case 3 (initial fracture permeability of $5 \cdot 10^{-10} \text{ m}^2$) in (a) and (b), Case 4 (initial fracture permeability of $1.5 \cdot 10^{-10} \text{ m}^2$) in (c) and (d), Case 5 (initial fracture permeability of 10^{-11} m^2) in (e) and (f). Aperture 1 is for the fracture to the left and Aperture 2 is for the fracture to the right.

3.3.1. Effect of variable flow rate

The results from the previous section suggested that higher flow rates could be used to mitigate uneven flow. As higher rates normally implies higher pumping costs, variable flow rates could be tested as a way to force narrower fractures that are on the limit to contributing over the edge. If a

high rate is used in the start phase, and flow evens out over some time, the difference between the apertures will decrease. The flow rate may then be lowered, and still be enough to maintain even flow.

The setup involves a two-fracture scenario with the same initial conditions as in case 5 with an initial permeability of 10^{-11} m². Case 5 led to uneven flow with a rate of 10^{-4} m²/s as presented in Section 3. It is of interest to test if it is sufficient to use a higher total rate for a limited time, before lowering the rate and see if the flow distribution stays even between the fractures. For the first 30 days a total flow rate of 10^{-3} m²/s is used, before lowering it to 10^{-4} m²/s. As can be seen in Fig. 21a, the fractures are quite evenly cooled after 30 days with the high rate stimulation, indicating that flow is even between the fractures. Fig. 21b, shows the aperture change over time where the flow rate is changed at 30 days. The even distribution of flow is maintained after the flow rate change. The reason for the increase in change in aperture with a lower rate, is because its plotted with aperture change over total water injected. The less water that is injected the slower it moves through the fracture, and the greater the heat exchange. Therefore, a faster increase in aperture per volume of water injected is found when lowering the rate.

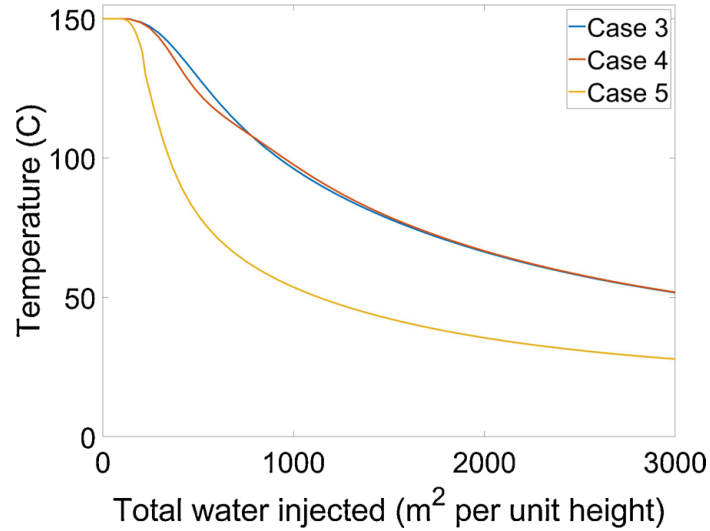


Fig. 13. Temperature of production fluid over total water injected for case 3, 4 and 5. Illustrates the effect of initial aperture on production data.

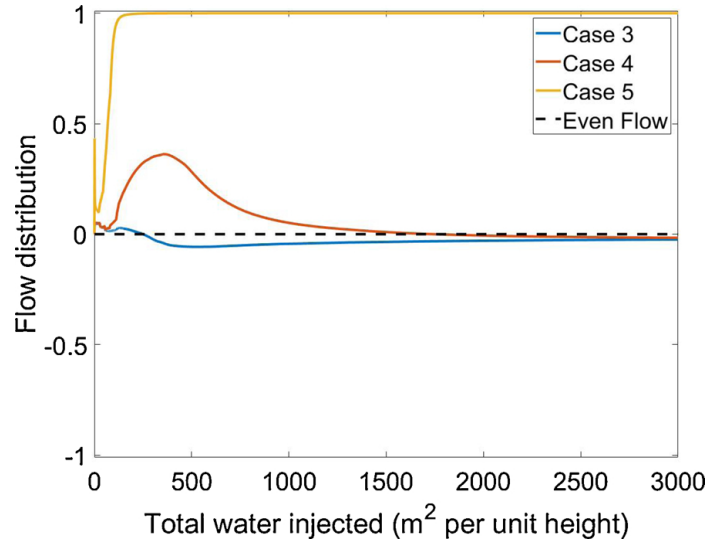


Fig. 14. Flow distribution over time for case 3, 4 and 5 (calculated as $1 - 2 \cdot \frac{q_a}{q_{tot}}$, where q_a is the flow going through fracture a, and q_{tot} is the total flow rate). -1 representing all the flow going through fracture 1, 0 representing even flow distribution between the fractures, and 1 representing all the flow through fracture 2.

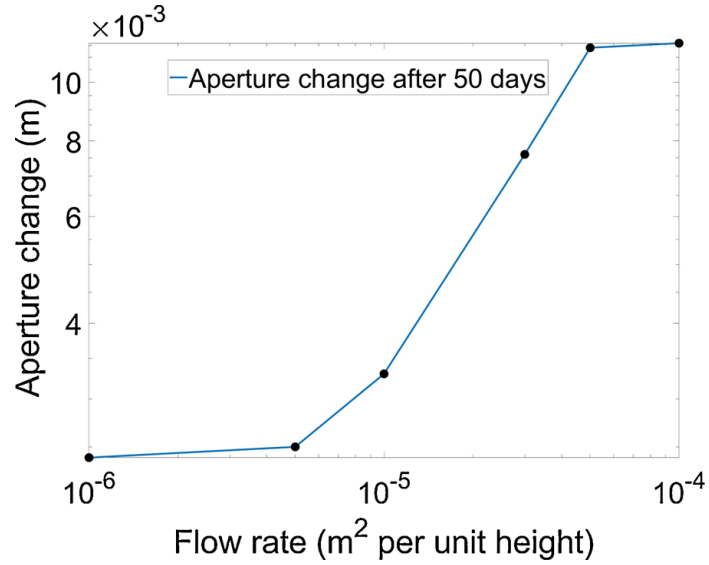


Fig. 15. Shows the average change in aperture for a 90 m fracture after 50 days as a function of flow rate on a log plot (the dots representing the numerical values and the line the trend).

496 Fig. 22 shows the comparison of production fluid temperature over the first year between the
 497 base case (case 5) and variable flow rate (case 8). As can be seen, the production fluid temperature
 498 decreases drastically at the higher rate, and it could be beneficial to minimize time spent at this
 499 rate. In addition, there is a temporary increase in temperature while injecting during the high

rate phase. This is due to the flow pattern change from uneven to even flow (see Fig. 23 for flow distribution and Fig. 24 for well pressure), which results in more fluid passing through the second, hotter, fracture. These results show that a higher rate can be used in the start phase to increase the aperture of both fractures, and when the rate is lowered the apertures are sufficiently open to allow for even flow. This suggests an operation means to improve flow connectivity of the reservoir, and hence production performance.

3.4. Effect of sequential flow

Here, a sequential flow through phase of the fractures is proposed to mitigate uneven flow and improve production. Fig. 25 shows the temperature profile at the end of each stage in a sequential injection. For the first 100 days, all the flow is directed through fracture A, after which the flow is directed for another 100 days through fracture B. Afterward, both are opened to flow. The result is that when flow is forced through the fracture, the fracture cools, and aperture and permeability increases (see Fig. 25). This is done for both fractures, increasing the permeability of both prior to the start of normal production. Fig. 25d shows the aperture change experienced by the two fractures over time. Fig. 22 compares the temperature of the production fluid to the base-case and variable flow rate intervention. Fig. 23, shows the flow distribution over time for the same three cases. As can be seen, close to even flow is obtained after the sequential injection, compared to case 5 where uneven flow is dominant from the beginning. These results indicate that sequential injection could be used as a tool to increase heat recovery from an EGS, where time spent in each stage can be minimized through trial and error. It might also be applicable for fracture networks, where certain parts of the network are injected into sequentially, but this would require further investigation.

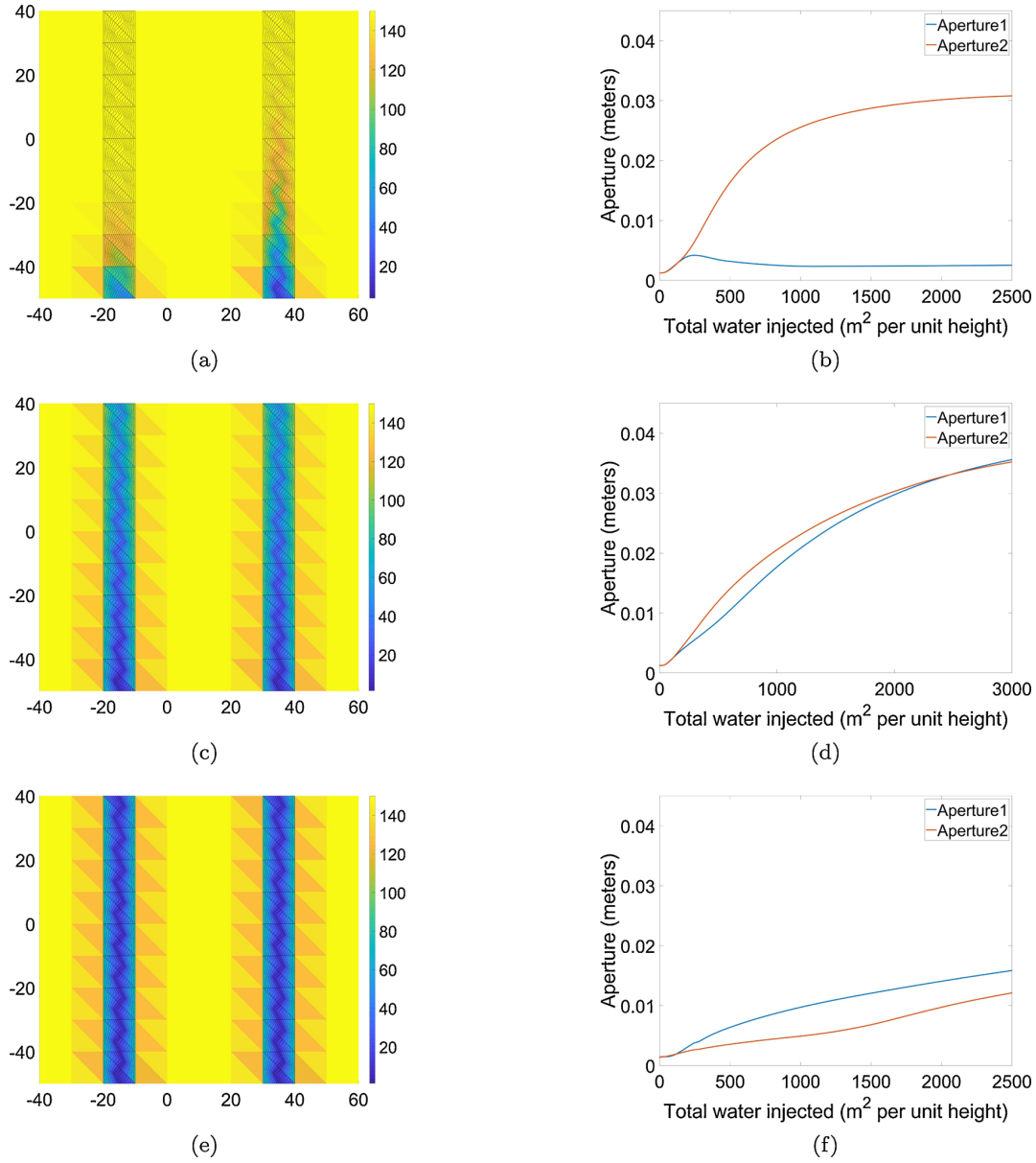


Fig. 16. The temperature field after a year of production and average aperture over total water injected for: Case 6 (total flow rate of 10^{-5} m²/s) in (a) and (b), Case 4 (total flow rate of 10^{-4} m²/s) in (c) and (d), Case 7 (total flow rate of 10^{-3} m²/s) in (e) and (f). Aperture 1 is the fracture to the left and Aperture 2 is the fracture to the right.

4. Discussion and conclusion

This study has shown that cooling related to EGS production does not necessarily result in uneven flow. The development of flow patterns during production depends on several factors, including the

ratio between fracture apertures, their values, and the total injection rate. A small difference in aperture, large aperture values and a large injection rate are all factors that increase the chance to avoid uneven flow. It was also found that flow behavior can transfer from initial uneven flow, to even flow over time, where the fracture that initially receives less fluid, can still have bigger relative aperture increase than its neighbor.

In order to minimize the negative effects of uneven flow on EGS production, two operational interventions were proposed and investigated; variable injection rates and sequential stimulation of the fractures. By injecting at a higher flow rate in the initial phase, before lowering the rate, even flow and better production was achieved, compared to uneven flow and poor production by injecting at a constant low rate. The higher initial flow rate allowed for significant increase in both fractures aperture, which facilitated even flow, compared to uneven flow when injection was performed at a constant low rate. Sequential stimulation of the fractures was found to facilitate even flow and good production. This is a concept where water is directed preferentially through each fracture in turn, increasing both apertures, before reverting to injection in both and an even flow regime.

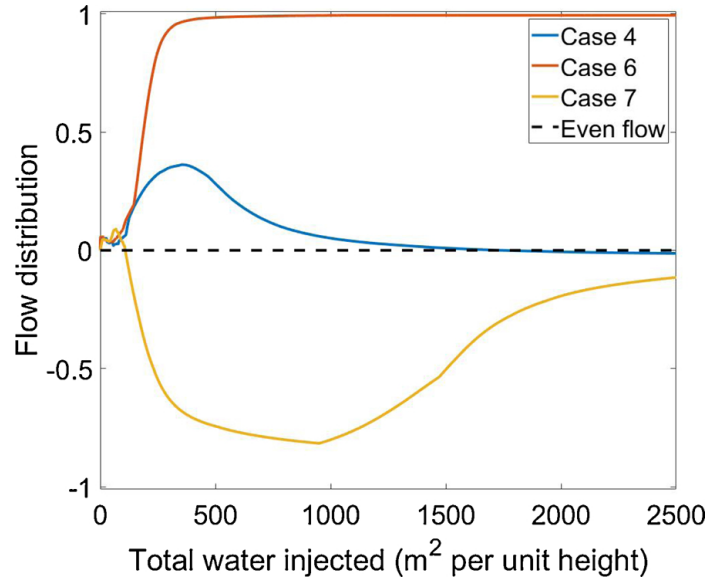


Fig. 17. Flow distribution over time for case 4, 6 and 7 (calculated as $1 - 2 \cdot \frac{q_a}{q_{tot}}$, where q_1 is the flow going through fracture 1, and q_{tot} is the total flow rate). -1 representing all the flow going through fracture 1, 0 representing even flow distribution between the fractures, and 1 representing all the flow through fracture 2.

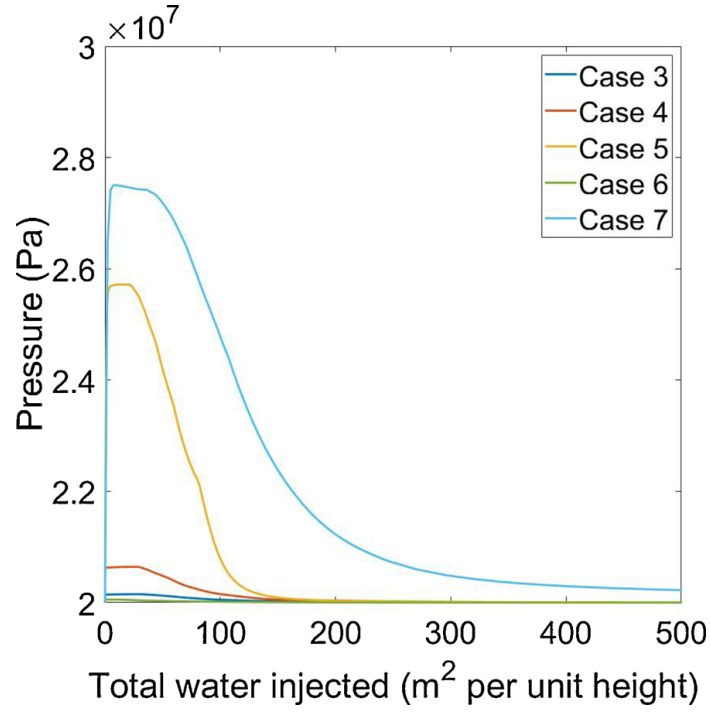


Fig. 18. Well pressure over total water injected (m^2 per unit height) for case 3 to 7.

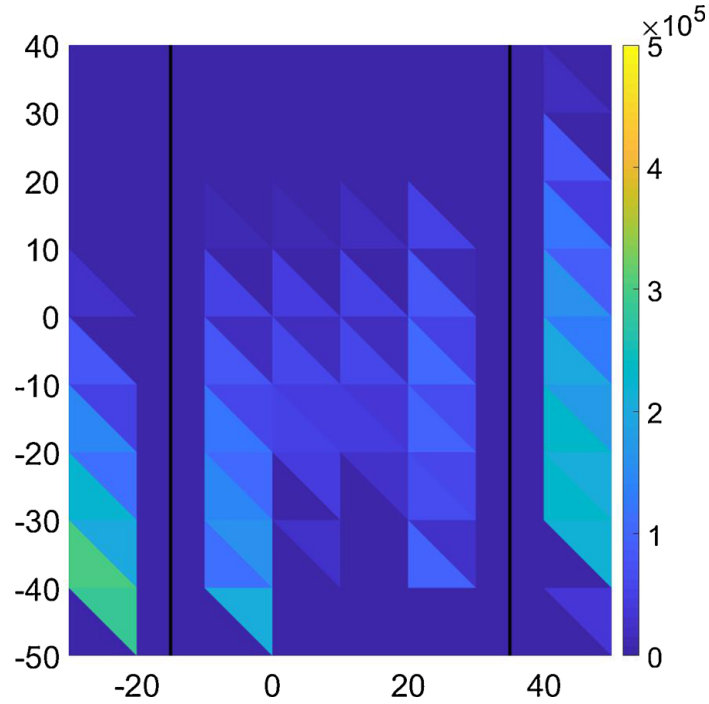


Fig. 19. Difference in compressive stress in x -direction with pressurized fractures at day 0 between case 7 (high injection rate) and case 6 (low injection rate). This illustrates the stress shadow exerted by the fractures in case 7 in comparison, as this is before significant cooling has occurred.

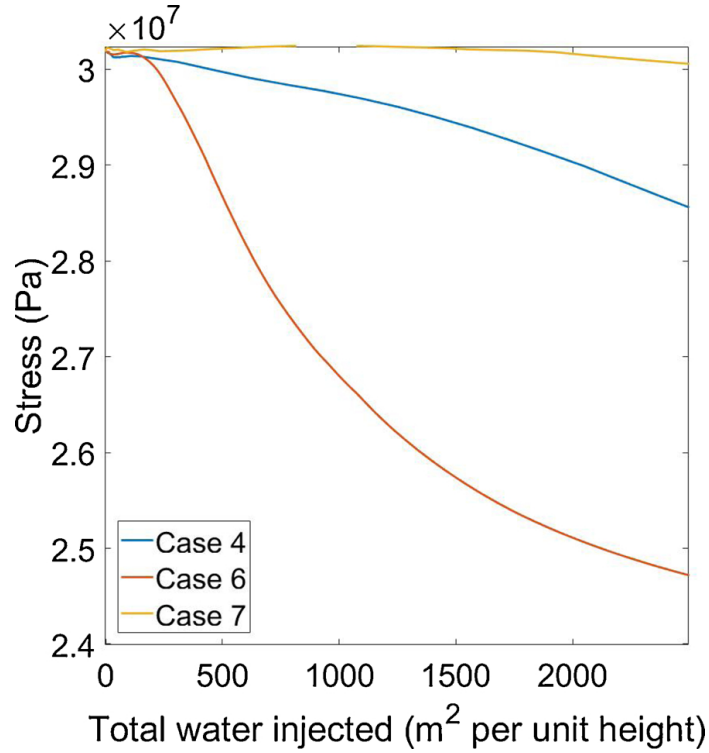


Fig. 20. Total stress in the middle between the fractures over time. The stress is normal to the fractures (x -stress), and results are shown for case 4 (medium injection rate), case 6 (lower injection rate) and case 7 (higher injection rate). Notice that the time scale is different for the cases, as they have different rates and are plotted over volume injected.

In addition, this study illustrates the need for advanced numerical models, taking into account THM processes, to accurately investigate thermal drawdown induced flow pattern changes, and to run geothermal production analysis on low permeability fracture networks. Changes in the stress state and pressure as a result of cooling, with its effect on fracture permeability, significantly affects flow pattern behavior, and therefore also production values.

The work presented here is performed within a 2D model. The main purpose has been to illustrate effects of the interaction between two fractures in a simplified way, demonstrating the feasibility of incorporating such effects into more complex schemes. The 2D model enables processes to be studied as such, whereas a 3D model obviously is required if the objective is to simulate real reservoir behavior. Having said that, it is worthwhile to point out that even if the modelling scheme is 3D, fractures in commonly used models are almost exclusively planar and placed by the modeler in a predefined way. Although that was also done here, the main motivation has been to

study flow distribution in a simplified setting before linking it to the ability of a discrete element
geomechanical code (like MDEM) where tortuous fractures controlled by the local stress field and
rock heterogeneities can be generated and propagated, eventually in 3D.

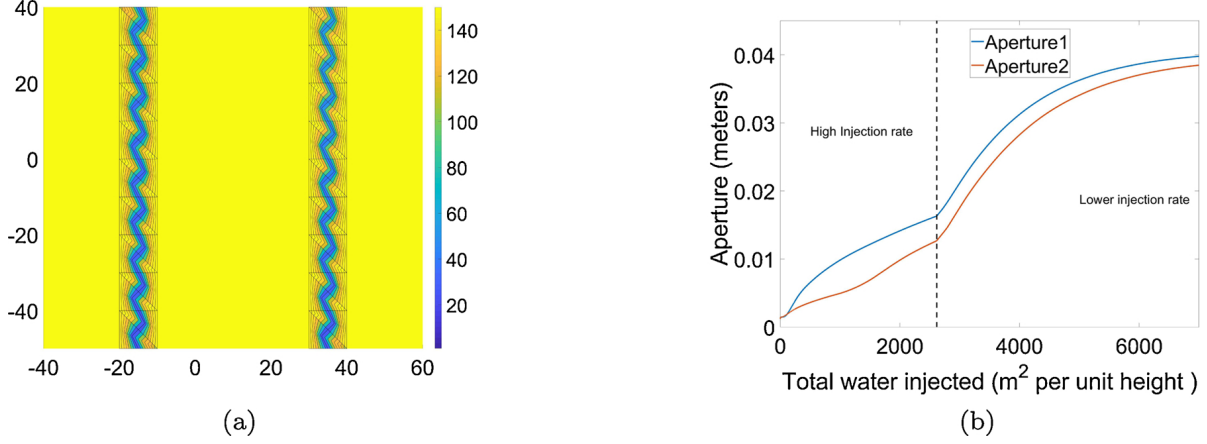


Fig. 21. (a) Temperature field after 30 days of high rate production (start of lower rate). (b) Change in aperture over time, where the rate is lowered by a factor 10 after 30 days. Aperture 1 is the fracture to the left and Aperture 2 is the fracture to the right.

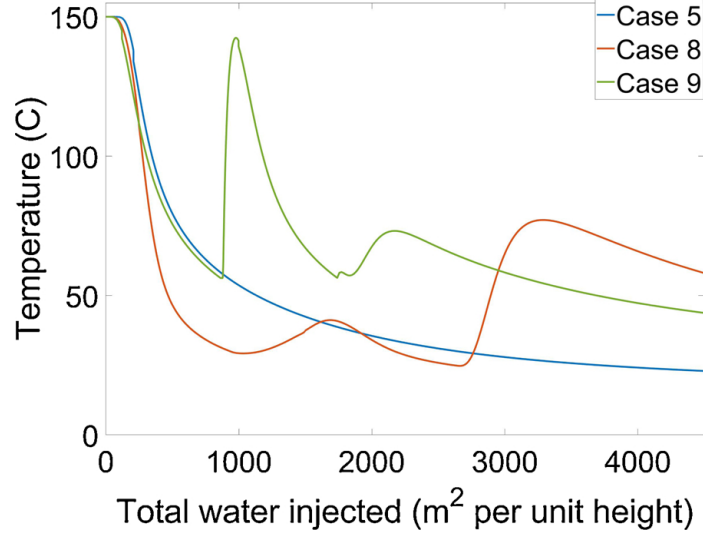


Fig. 22. Temperature of production fluid for case 5, 8 and 9. Illustrates the effect of variable flow rate and sequential flow as operational techniques to mitigate uneven flow and improve recovery.

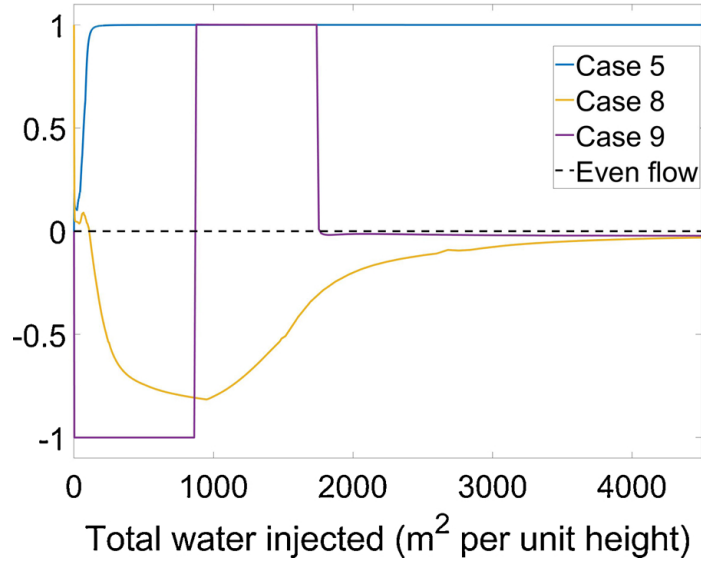


Fig. 23. Flow distribution over time for case 5, 8 and 9 (calculated as $1 - 2 \cdot \frac{q_a}{q_{tot}}$, where q_1 is the flow going through fracture 1, and q_{tot} is the total flow rate). -1 representing all the flow going through fracture 1, 0 representing even flow distribution between the fractures, and 1 representing all the flow through fracture 2.

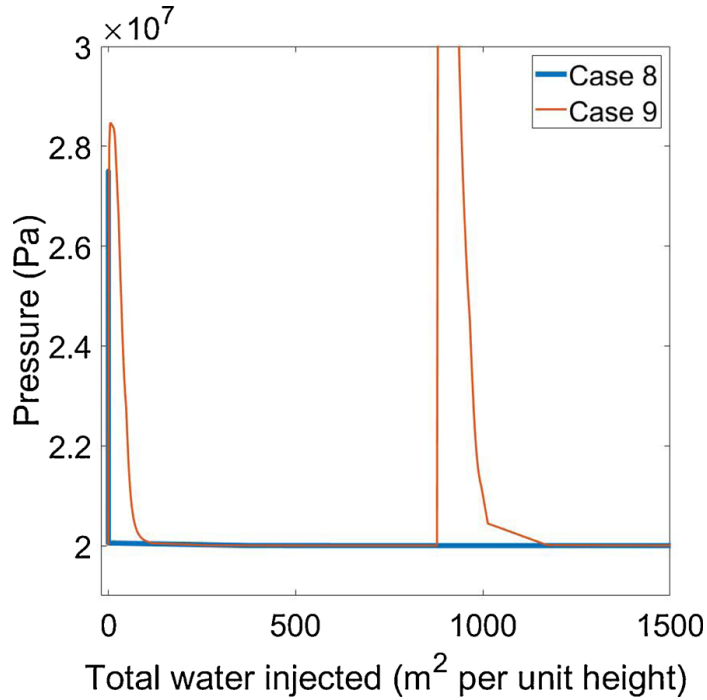


Fig. 24. Well pressure over total water injected (m^2 per unit height) for case 8 and 9.

553 In a complex natural fracture network with a large number of fractures, it seems reasonable that
554 there will always be some uneven flow, where low permeability pathways do not receive enough flow

555 to cool and increase in aperture, and therefore continue to receive less flow. There is, however,
556 a chance that a series of higher permeability fractures will receive enough flow to cool, and that
557 flow will even out between these fractures, and not necessarily concentrate to one large one. These
558 results, also show that it could be possible to increase the number of contributing fractures by
559 wellhead interventions prior to the start of normal production, either through sequential injection or
560 through variable injection rates. A focus for future work will be to include a more complex fracture
561 network between two wells, and investigate the effects of sequential injection on increased recovery.

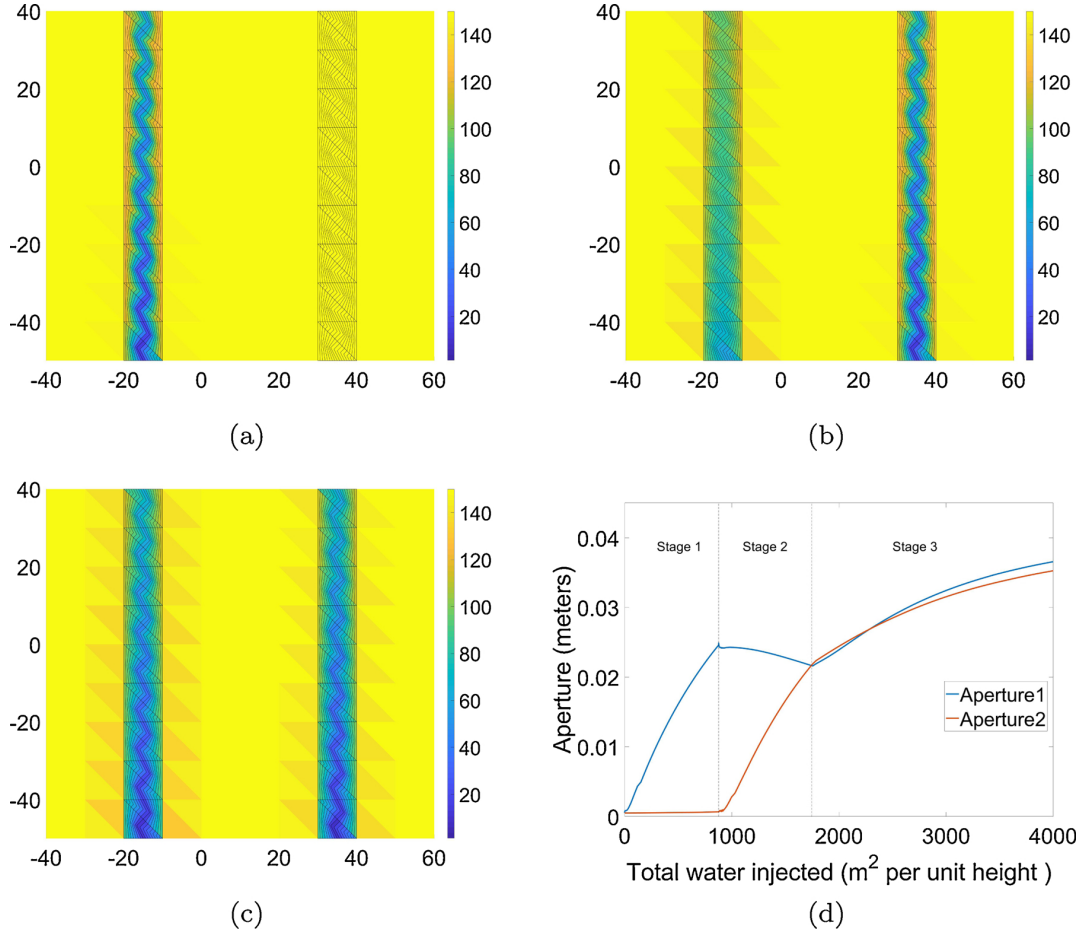


Fig. 25. Temperature field after each stage in sequential stimulation case (case 5, see Table 2 for more info) with: Stage 1 (after 100 days) in (a), Stage 2 (after 200 days) in (b) and Stage 3 (after 300 days) in (c). The aperture change for both fractures over total water injected is plotted in (d). Aperture 1 is the fracture to the left and Aperture 2 is the fracture to the right.

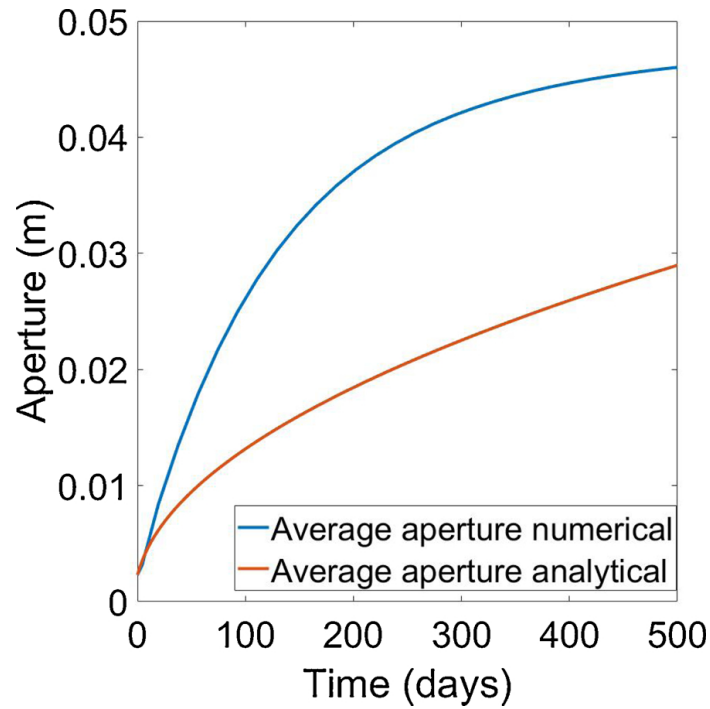


Fig. 26. Average aperture of the fracture in case 2 over the first 500 days of production. Numerical (in blue) vs. analytical (in red) solution. (For interpretation of the references to color in this figure legend, the reader is referred to the web version of this article.)

Declaration of interests

None declared.

Declaration of Competing Interest

The authors report no declarations of interest.

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Appendix A. Model validation: an analytical comparison of the stress shadow from a 2D fracture

The aperture increase over time is compared to an analytical solution presented by Ghassemi Ghassemi et al. (2008). The analytical solution used is for an impermeable rock, where the aperture at a distance $\mathbf{x}$ from the injection point at a time $\mathbf{t}$ after injection start is given as

$$\omega(x, t) = \xi_1 \exp(-\xi_2 x^2) - \xi_3 x \operatorname{erfc}(x \sqrt{\xi_2}) + \omega_0 \quad (18)$$

where

$$\xi_1 = \frac{4\chi T^\Delta \sqrt{K_r t}}{\sqrt{\pi \rho_r c_r}}, \quad \xi_2 = \frac{K_r \rho_r c_r}{(q_0 c_f \rho_f)^2 t}, \quad \text{and} \quad \xi_3 = \frac{4\chi T^\Delta K_r}{q_0 \rho_f c_f}.$$

Here $\chi = \alpha_T(1 + \nu)/(1 - \nu)$, ν is the Poisson's ratio, α_T the linear coefficient of thermal expansion, T^Δ the difference in temperature between the injection fluid and reservoir, K_r the rock's thermal conductivity, ρ_r the rock's density, c_r the specific heat of the rock, ρ_f the injection fluid density, c_f the specific heat of the injection fluid and q_0 the injection rate. For more details on the solution see Ghassemi et al. (2008). Fig. 26 shows the aperture comparison between MDEM and the analytical solutions. The rapid increase in the beginning is due to the big difference in temperature between the injection fluid and the surrounding rock. Heat exchange is greater with a larger difference in temperature, resulting in the early drastic increase in aperture. Later, as the rock cools, the difference in temperature between the rock and the fluid is smaller, and the rate of aperture change decreases. There is a quantitative difference between the analytical model and MDEM, however, with similar sized aperture increase over similar time scales, where MDEM models a larger aperture than the analytical model. The difference is due to several differences in assumptions and model complexity: The analytical model not taking into account fracture stiffness, assuming one-dimensional heat flow and rock displacement, assuming that the fracture is already open under in-situ stress and pressure, and does not couple the hydraulic changes over time in response to geomechanical development. In the numerical setup with MDEM the initiation process of pressurizing and opening the fracture is modelled. An initial aperture is given to the fracture in MDEM, however, this is a hydraulic aperture, allowing for some flow, but the fractures are mechanically closed under the combination of stress and pressure. During the initiation process the pressure in the fracture may have to exceed the minimal

principal stress to facilitate for the given rate. The fractures will then open, and the aperture will not only be dependent on cooling. As the fracture opens up due to cooling with a constant injection rate, the pressure in the fracture drops. This changes the pressure distribution within the fracture. In addition, a fixed pressure sink equal to the pore pressure is used for production modelling. During production, the in-situ stress might drop below the original pore pressure, but the pressure in the fracture will not drop below the production pressure. The fracture will therefore open more than if fracture was just open under combination of pressure and in-situ stress. The fracture does not infinitely open without resistance due to the fracture and reservoir stiffness. These differences may explain the higher apertures modelled by MDEM compared to the analytical model. The flow rate going through the fracture will also influence the increase in aperture, both the average aperture but also the aperture profile. Lower rates may only be enough to cause aperture increase at the very start of the fracture, while very high rates will give a more even aperture increase across the whole fracture.

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