EGS Reservoir Modeling for Developing Geothermal District Heating at Cornell University

Preprint

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1 National Renewable Energy Laboratory
2 Cornell University

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EGS Reservoir Modeling for Developing Geothermal District Heating at Cornell University

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Keywords

District Heating, Cornell University, Earth-Source Heat, EGS, Reservoir Modeling

ABSTRACT

Cornell University is pursuing development of an enhanced geothermal system (EGS) for providing heating to its main campus in Upstate New York. A ~3 km deep vertical observation well ("CUBO") was drilled in 2022 to characterize the subsurface using wellbore logging, borehole imaging, fluid sampling, mini-frac tests, coring, and drill cutting analysis. Down-hole temperatures measured at 3 km depth are about 80°C, sufficiently high for direct-use heating. The well drilled through generally low porosity and low permeability Paleozoic sedimentary formations and into metamorphic basement rock, encountered at about 2.8 km depth.

Leveraging subsurface data obtained through CUBO, we investigated technical feasibility and design requirements of a doublet well system with horizontal laterals connected to a fracture network created through hydraulic fracturing. The EGS reservoir is sized to provide a nominal heat output in the range 5 to 10 MW_{th} of continuous heating over a 15-year lifetime with limited thermal drawdown. We applied the Gringarten multiple parallel fractures model, the Cornell Discrete Fracture Simulator FOXFEM, and the commercial simulator ResFrac to estimate required heat transfer area and design a potential hydraulic stimulation treatment. Reservoir simulations indicate that, depending on fluid flow rate and injection temperature, 2 to 3 km^2 of effective fracture heat transfer area is required to supply the target heat output of 5 to 10 MW_{th} over 15 years.

1. Introduction

Cornell University aspires to become a carbon-neutral university by 2035 through its Climate Action Plan. A key pillar of this plan is decarbonizing the bulk of the heating load of the university's main campus in Ithaca, New York, with deep geothermal energy or "Earth Source Heat" (Tester et al., 2023). Over the past decade, various studies have been conducted to characterize the subsurface, investigate designs to integrate the geothermal system with the existing campus energy infrastructure, and assess the overall technical and economic feasibility. In the summer of 2022, a 9,791 ft (2,984 m) deep exploratory well, named CUBO (Cornell University Borehole Observatory) was drilled to provide insights on the mechanical, thermal and hydrologic subsurface conditions using data collected through logging, coring, borehole imaging, mini-frac tests, assessing drill cuttings, and fluid sampling (Fulton et al., 2024). CUBO was drilled through about 9,400 ft (2,865 m) of Paleozoic sedimentary formations overlaying low-grade metamorphic basement rocks. Bottom-hole subsurface temperatures (after correcting for cooling due to drilling fluid circulation) are around 80°C, corresponding to a geothermal gradient of about 23°C/km. Analysis of mini hydraulic fracture testing combined with density logging suggests a strike-slip stress regime, i.e., the maximum and minimum principal stresses are horizontal and the intermediate principal stress is vertical.

Given the recent advances in EGS technology (e.g., by Fervo Energy and FORGE), this study explored developing a doublet system with long horizontal laterals at about 3 km vertical depth intersected by a large number of parallel vertical fractures created using multi-stage hydraulic stimulation (Figure 1). We leveraged three subsurface simulation models to explore potential reservoir designs capable of producing 5 to 10 MW_{th} of heat with limited thermal decline over a 15-year lifetime. Study objectives were (1) estimating the required number of fractures and required fracture area to sustain long-term heat production, (2) designing a potential hydraulic stimulation treatment program, and (3) comparing predicted reservoir performance across reservoir simulators.

2. Methodology

The three models applied to explore EGS reservoir performance are (1) the multiple parallel vertical fractures model by Gringarten et al. (1975) (Section 3), (2) the FOXFEM finite element simulator for heat transfer in fractures developed by Cornell (Fox, 2016; Hawkins, 2017; Section 4), and the commercial simulator ResFrac, allowing for simulating both hydraulic simulation and long-term fluid circulation (Section 5). The analytical Gringarten heat transfer model considers uniform flow through multiple parallel fractures. It does not calculate the pressure field, only the temperature field of the fluid. We applied the model as implemented in Python in GEOPHIRES (Beckers and McCabe, 2019; Ross and Beckers, 2023) and available on GitHub (NREL, 2024.). The model is easy to apply and provides a quick solution but assumes a simplified flow field with the fluid sweeping the entire area of the fracture with identical velocity.

The thermal-hydraulic FOXFEM simulator calculates the velocity field and corresponding pressure distribution of the fluid within the fracture, in addition to the fluid temperature field, thereby more accurately capturing the heat sweep with flow through a fracture. It can account for a variable aperture distribution but does not account for gravity (i.e., buoyancy effects due to difference in fluid density) and simulates only a single, discrete fracture. The tool is implemented in MATLAB and applies Green's functions in the Laplace domain to rapidly calculate the heat transfer between the fluid and the rock.

The thermal-hydraulic-mechanical simulator ResFrac is an advanced, commercial simulator that simulates both hydraulic stimulation to create fractures and long-term fluid circulation to estimate heat extraction. It is the most advanced simulator of the three applied, capable to simulate all relevant physics at play but has a steeper learning curve and simulations take a longer time (hours vs. seconds with the Gringarten model and minutes with the FOXFEM model).

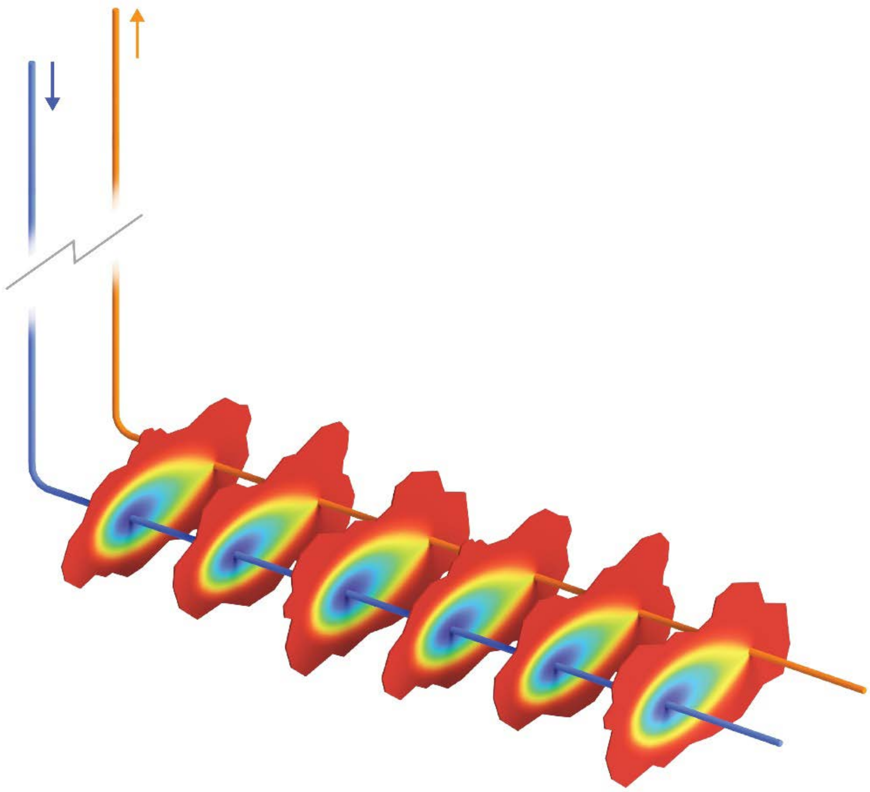


Figure 1: Simplified diagram of doublet EGS reservoir with multiple parallel vertical fractures connecting long horizontal laterals.

3. Thermal Simulations using Gringarten Multiple Parallel Fractures Model

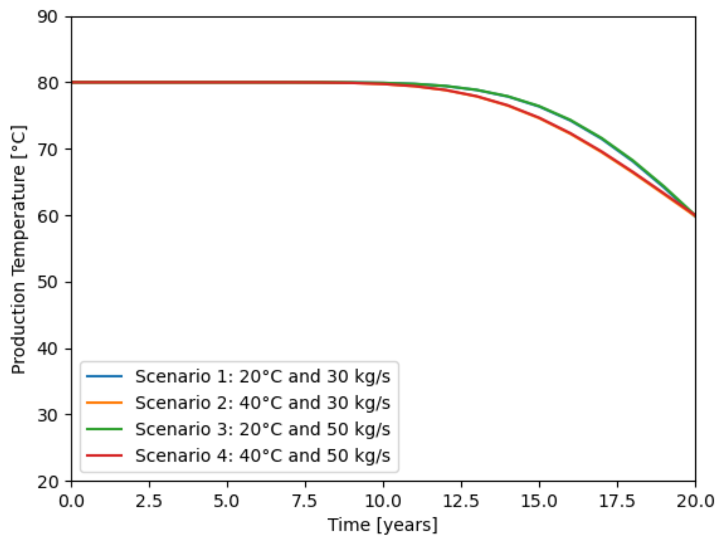
We applied the analytical Gringarten et al. (1975) multiple parallel fractures model to investigate the required fracture heat transfer area to sustain heat production over a ~15-year lifetime. We considered four scenarios, exploring two different flow rates (30 and 50 kg/s) and two different injection temperatures (20° and 40°C). The design assumes two horizontal laterals spaced relatively close together at 150 m and with a fracture height of 150 m. The fracture spacing is set to 15 m. For comparison, Project Red in Nevada had a lateral well spacing of about 110 m (Norbeck and Latimer, 2023). For each scenario, we calculated the required number of fractures and corresponding lateral length to limit the temperature decline to 20°C after 20 years. The initial rock temperature is set to 80°C. All input parameters are listed in Table 1.

The required number of fractures (and corresponding lateral length and total heat transfer area) and initial and final thermal output for each scenario are presented in Table 1. All four scenarios have a similar production temperature profile (Figure 2a) but show a wide range in thermal output, with the initial thermal output ranging from 5 to over 12 MW_{th}, depending on the injection temperature and flow rate (Figure 2b). The lateral length required falls in the range of 1,200 to 2,300 m, and the number of fractures lies in the range of 85 to 157. For comparison, Project Red had a lateral length of about 1 km and about 100 perforation clusters in total (over 16 stages) (Norbeck and Latimer, 2023). The high thermal output scenario (Scenario 3) required the longest lateral length and highest number of fractures with a total fracture area of about 3.5 km^2. When flowing at only 30 kg/s instead of 50 kg/s (Scenario 1), a fracture heat transfer area of 2.1 km^2 is sufficient to maintain a production temperature above 60°C. However, decreasing the flow rate also decreases the thermal output (initial thermal output drops from 12.5 to 7.5 MW_{th}).

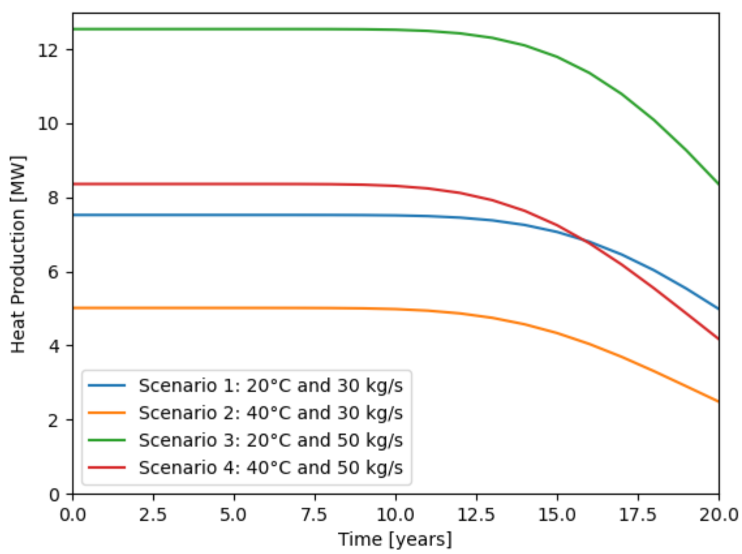
Table 1: Input parameter and simulation results using Gringarten multiple parallel fractures model.

	Scenario 1	**Scenario 2**	**Scenario 3**	**Scenario 4**
Simulation Input Parameters				
Rock initial temperature	80°C			
Fluid injection temperature	20°C	40°C	20°C	40°C
Fluid flow rate	30 kg/s		50 kg/s	
Fluid density	1,000 kg/m3			
Fluid specific heat capacity	4,180 J/kg/K			
Rock thermal conductivity	2.8 W/m/K			
Rock density	2,800 kg/m^3			
Rock specific heat capacity	1,000 J/kg/K			
Fracture length = lateral spacing	150 m			
Fracture height	150 m			
Fracture spacing	15 m			
Number of fractures	94	85	157	142
Simulation Results				
Initial heat production	7.5 MW_{th}	5.0 MW_{th}	12.5 MW_{th}	8.4 MW_{th}
Heat production at 20 years	5.0 MW_{th}	2.5 MW_{th}	8.4 MW_{th}	4.2 MW_{th}
Production temp. at 20 years	59.8°C	59.8°C	60.0°C	60.0°C
Lateral length	1,380 m	1,245 m	2,325 m	2,100 m
Total heat transfer area	2.1 km^2	1.9 km^2	3.5 km^2	3.2 km^2

The required fracture geometry, and temperature and heat production results provided in Table 1 and Figure 2 are high-level estimates, given the simplifications in the Gringarten model. In Section 4, a more advanced simulator (FOXFEM) is applied, which calculates both the fluid velocity field and corresponding pressure distribution, in addition to the fluid temperature field.



(a)



(b)

Figure 2: Production temperature (a) and corresponding heat production (b) for the four scenarios listed in Table 1. In all four scenarios, the number of fractures (and lateral length) was set to limit the production temperature decline to 20°C after 20 years of continuous operation. The heat production scales with the flow rate and difference between production and injection temperature, causing the wide range in heat production among the four scenarios. In (a), scenarios 1 and 3, and 2 and 4 overlap.

4. FOXFEM Thermal-Hydraulic Simulations

We applied the FOXFEM simulator, developed at Cornell, to estimate more accurately the heat extraction with fluid flow through a fracture located in a conduction-only medium. The tool only simulates a single fracture but simulates both the temperature and velocity field of the fluid, and can account for a variable aperture distribution.

We ran a simulation for a single fracture with FOXFEM to compare the heat sweep and effective heat transfer area with the Gringarten model, which for a single fracture simplifies to an error function. The fracture modeled is a circular fracture with a 160-m radius, with injection and production points spaced 150 m apart (Figure 3a). Rock and water properties are listed in Table 1, with water flow rate through the fracture set to 3 kg/s and injection temperature set to 20°C. The fluid temperature field after 20 years of operation is characteristic for a dipole flow field and indicates regions of the fracture with limited heat extraction from the rock (Figure 3b: yellow-colored regions). The production temperature for this case is shown in Figure 4 with the blue line, showing a temperature decline of about 30°C after 20 years. The same fracture area (0.081 km^2) with a uniform flow field as simulated with a modified Gringarten model for a single fracture shows a temperature drop of only 18°C after 20 years (red curve in Figure 4). The equivalent area with uniform flow to obtain the same temperature decline as with a dipole model is 0.054 m^2 (yellow line in Figure 4). This translates to roughly 66% heat sweep efficiency for a dipole model compared to the idealized uniform flow fracture model (assumed in Gringarten model). The heat sweep efficiency value can be different for different fracture geometries, flow rates, etc.

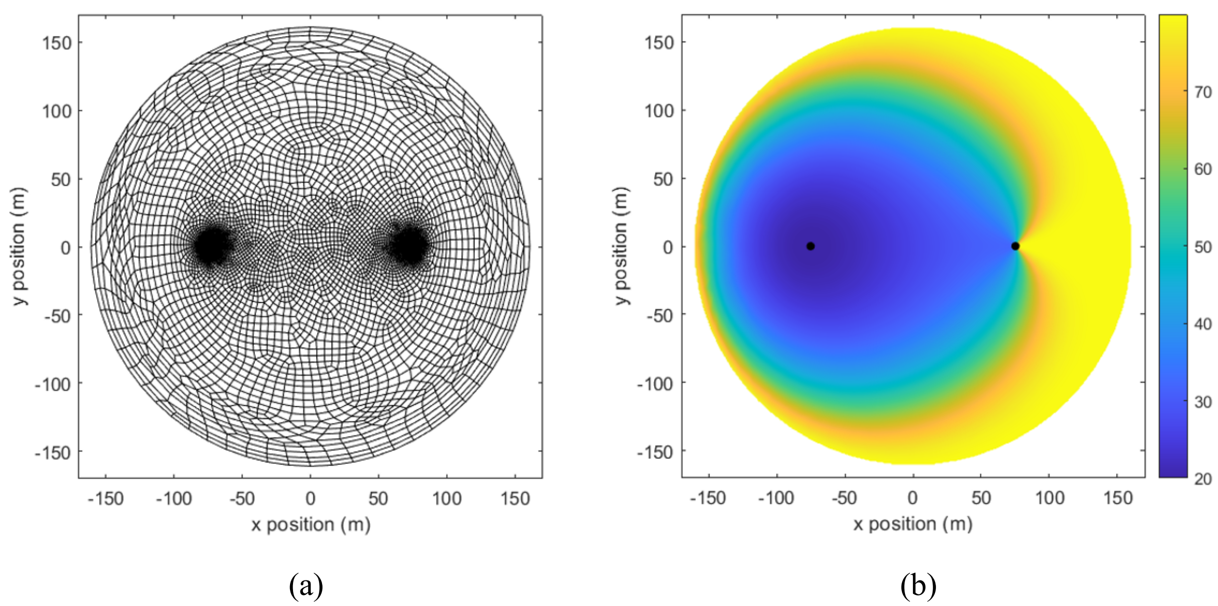


Figure 3: Mesh (a) and fluid temperature field after 20 years of operation (b) for single fracture flow simulated with the FOXFEM simulator. Fracture has radius of 160 m with injection (left black dot) and production (right black dot) spaced 150 m apart.

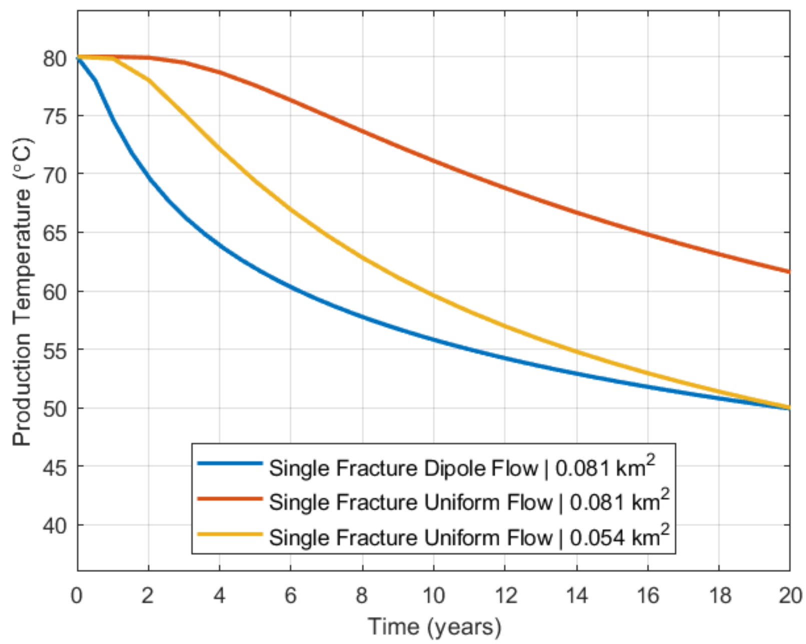


Figure 4: Production temperature profile for three scenarios: (1) single fracture dipole flow simulated with FOXFEM (as in Figure 3), (2) uniform flow in rectangular fracture for same fracture area, and (3) uniform flow in rectangular fracture with 34% reduction in fracture area.

The results shown in Figure 4 assume a uniform aperture field. Next, we explored the impact of the aperture distribution on the temperature field and production temperature. We considered three additional scenarios: a random aperture distribution between 0.5 and 2 mm (case 2), a high aperture flow path representing a "short-circuit" (case 3), and a low aperture blockage positioned in between the injection and production point (case 4). The aperture field and temperature field after 20 years for these three cases are shown in Figure 5. The production temperature profiles are presented in Figure 6. This analysis indicates the aperture field can have significant impact on the production temperature, particularly in the case of a channeled flow path, which concentrates the heat extraction along the flow path resulting in a low sweep efficiency. In real EGS reservoirs, proppants can be used to keep fractures open to facilitate obtaining high sweep efficiencies. Tracer testing can help with characterizing the effective heat transfer area. Techniques are currently being developed to mitigate high aperture flow paths, e.g., using temperature-dependent swelling particles.

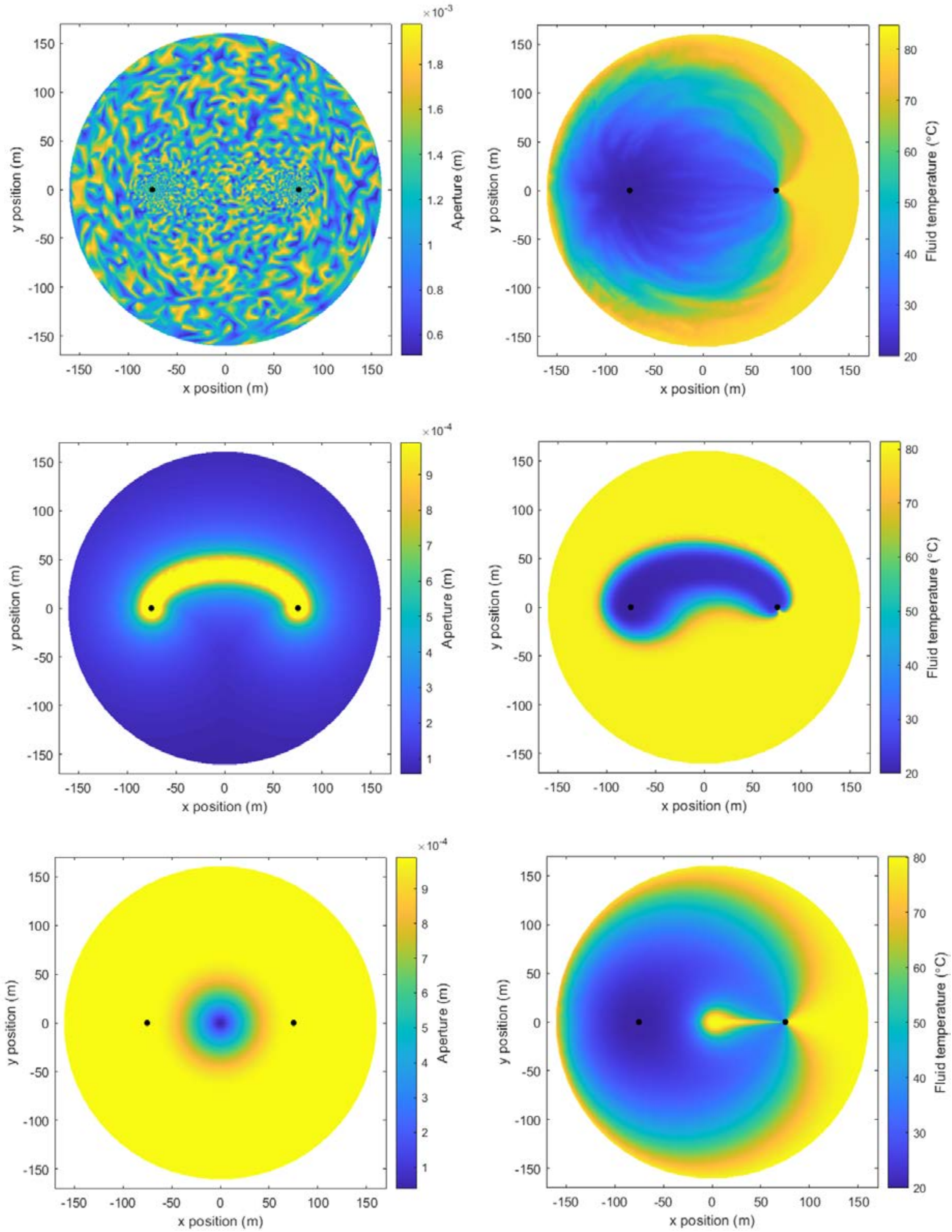


Figure 5: Fluid temperature field after 20 years (right column) for three additional aperture fields (left column): (case 2) random aperture (top), (case 3) high aperture flow path (middle), and (case 4) low aperture center blockage (bottom).

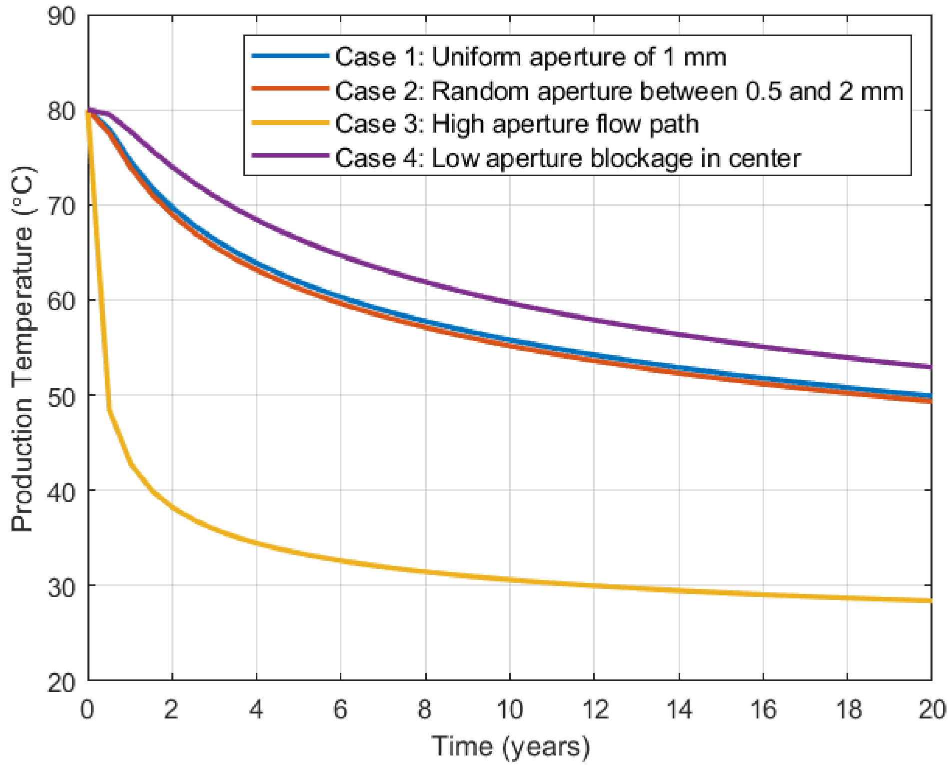
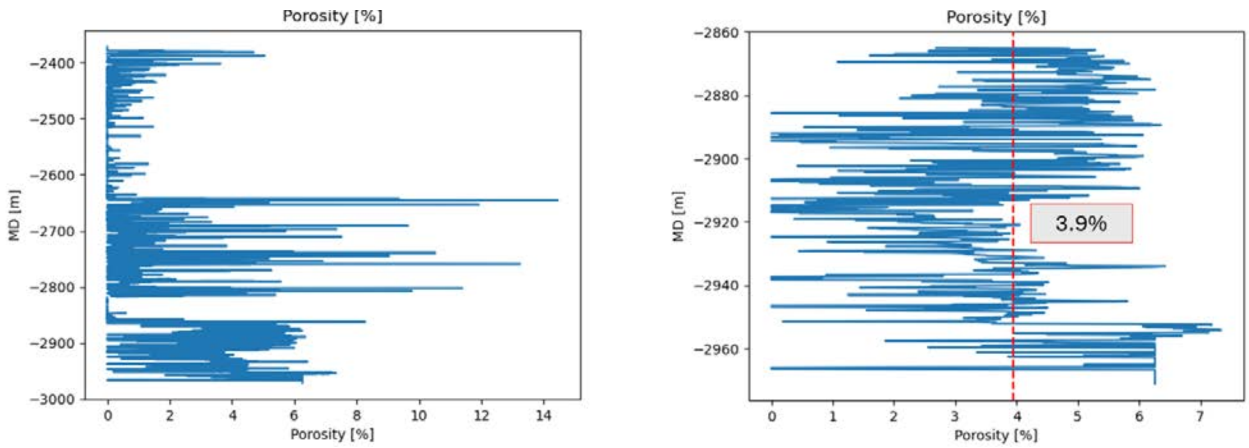


Figure 6: Production temperature profile for four aperture fields: (case 1) uniform aperture field (Figure 2), (case 2) random aperture field, (case 3) high aperture flow path, and (case 4) low aperture block in center. Corresponding aperture and temperature fields for cases 2, 3, and 4 are shown in Figure 5.

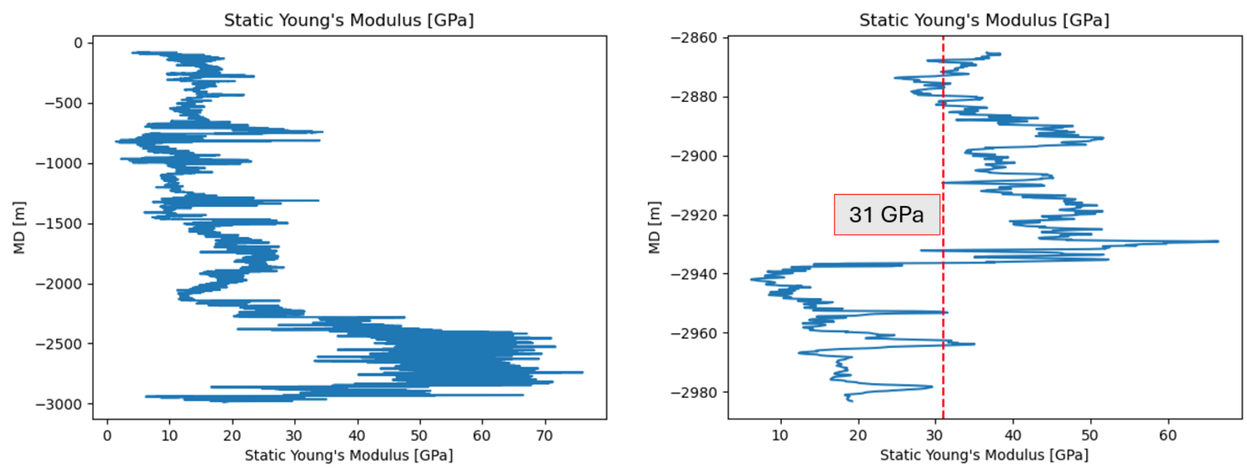
5. ResFrac Thermal-Hydraulic-Mechanical Simulations

5.1 LAS Data Processing

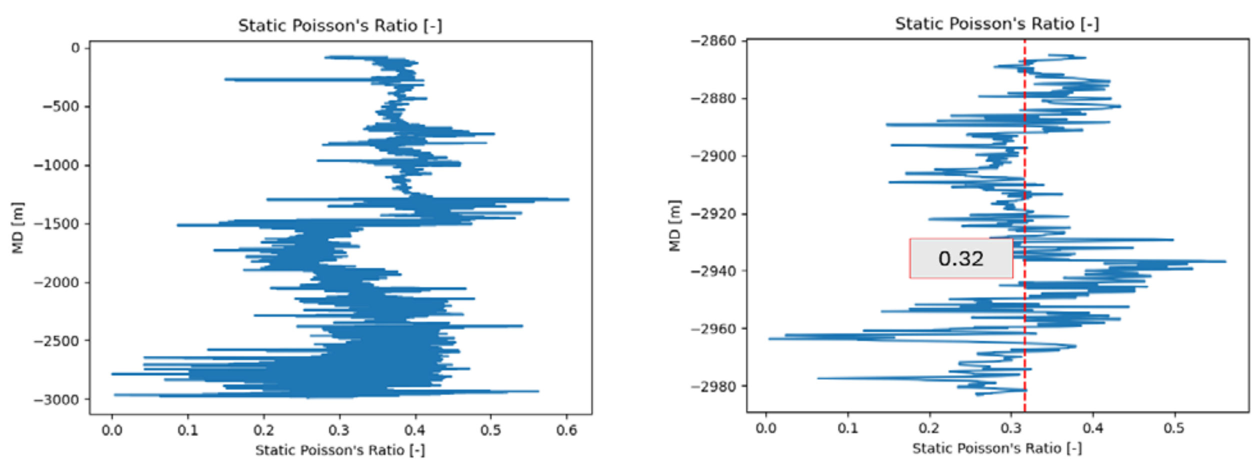
We utilized the commercial simulator ResFrac to explore hydraulic stimulation treatments and analyzed the corresponding thermal performance with long-term fluid circulation. We leveraged collected logging data from CUBO stored in a LAS file, provided as input to ResFrac. Figure 7 presents various logged properties with the entire profile shown on the left and the zoomed in profile for the bedrock shown on the right. The average values for the bedrock are provided as input to ResFrac, i.e., porosity of 3.9%, Young's modulus of 31 GPa, Poisson's Ratio of 0.32, and Biot coefficient of 0.58. A hydrostatic column is assumed for pore pressure with pressure gradient of 10.8 MPa/km.


Porosity [%]
MD [m]
Porosity [%]
Porosity [%]
MD [m]
Porosity [%]
3.9%

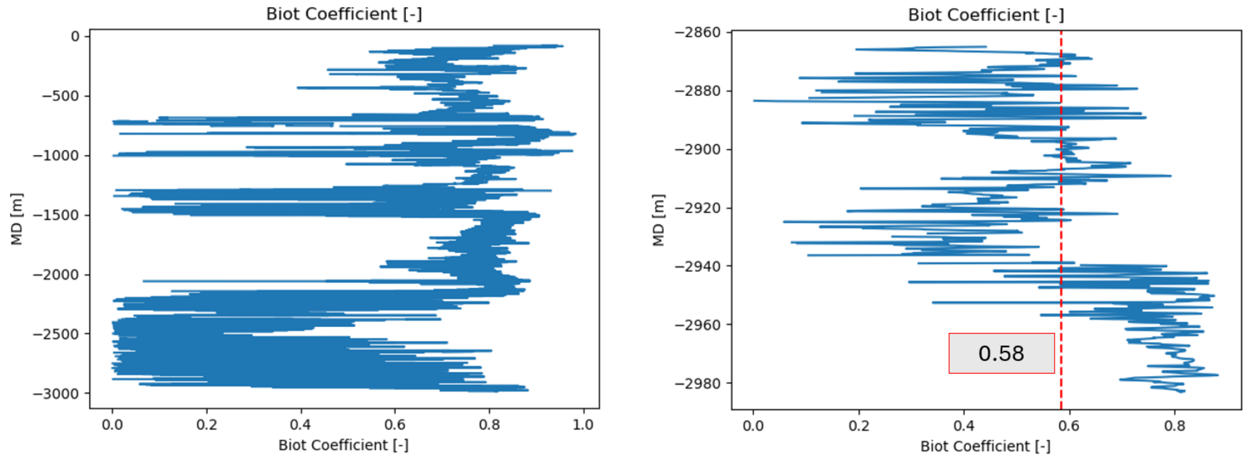
(a)


Static Young's Modulus [GPa]
MD [m]
Static Young's Modulus [GPa]
Static Young's Modulus [GPa]
MD [m]
Static Young's Modulus [GPa]
31 GPa

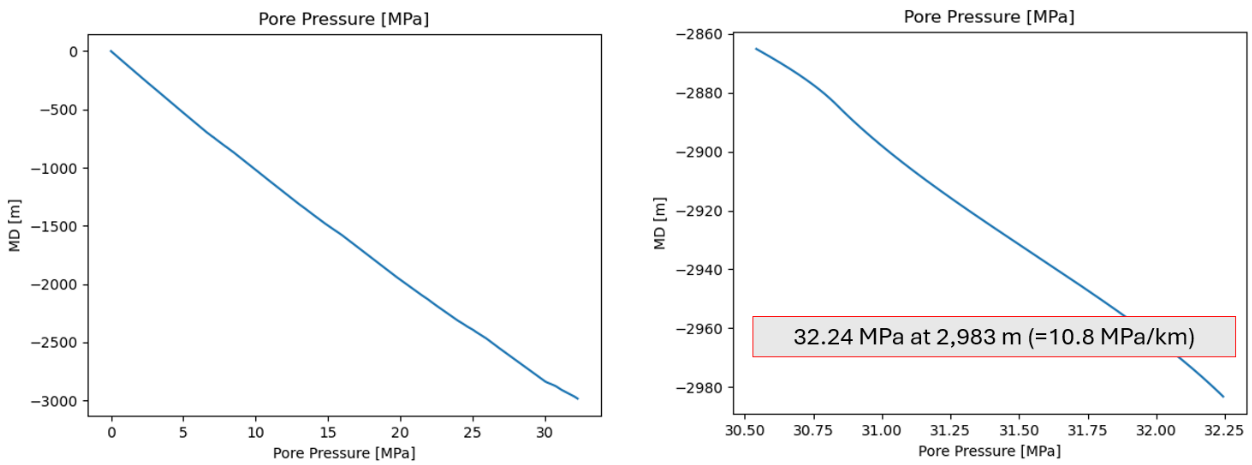
(b)


Static Poisson's Ratio [-]
MD [m]
Static Poisson's Ratio [-]
Static Poisson's Ratio [-]
MD [m]
Static Poisson's Ratio [-]
0.32

(c)



(d)



(e)

Figure 7: CUBO well LAS data for (a) porosity, (b) static Young's modulus, (c) static Poisson's ratio, (d) Biot coefficient, and (e) pore pressure. Plots on the left are for the entire well, and plots on the right are for the bottom part of the well in bedrock. Average values for bedrock are represented with red dashed lines and provided as input in ResFrac.

5.2 ResFrac Simulations

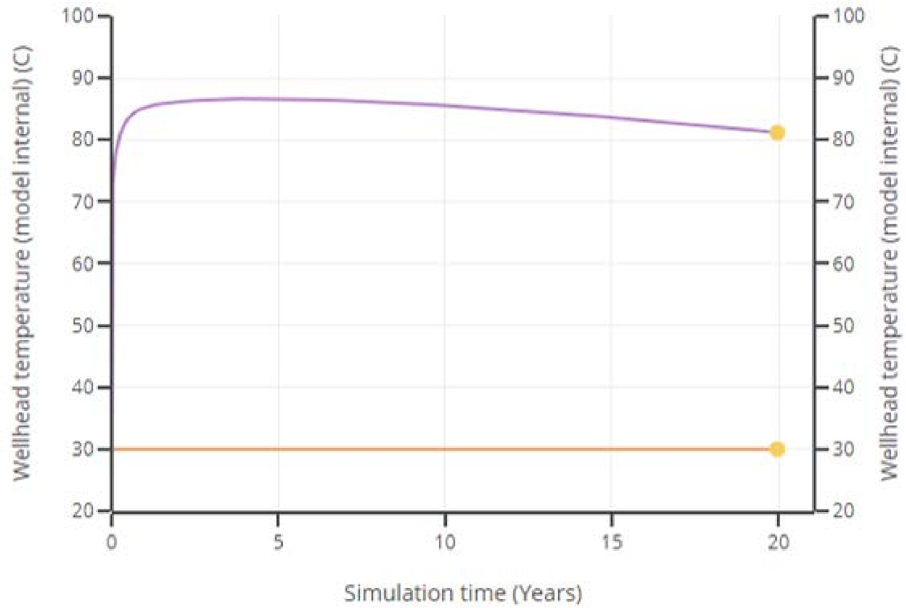
ResFrac simulations were conducted to design a potential hydraulic stimulation treatment and further explore the necessary number of fractures and fracture area to obtain long-term heat production with commercially acceptable thermal decline. Dozens of simulations were run considering different wellbore and stimulation designs. For this paper, we selected a promising case study with design parameters listed in Table 2 and simulation results presented in Figure 8. In this design, we considered 20 stages where each stage has five clusters, for a total of 100 fracture clusters. To save on computational time, only one stage was simulated using a no-flux condition as a domain boundary condition in between the stages. The injection and production lateral were spaced 150 m apart, the clusters were spaced 20 m apart, and we stimulated both laterals. The lateral length for each well is about 2 km. Stress field (with linear gradient) and uniform rock properties were specified using data from the wellbore logging (as stored in the LAS file; Section

5.1) and documented in Fulton et al. (2024). We limited the number of perforations per cluster to four and the perforation diameter to 0.01 m to enforce a sufficiently large pressure drop across the perforations, facilitating uniform fracture creation and uniform inflow across all fractures. The wellbore diameter was set to 0.18 m and the wellbore heat transfer coefficient to 50 $W/m^2/K$. We specified a matrix permeability multiplier of 10 when the pore pressure is 20 MPa above initial pore pressure in the matrix to account for effects such as small existing natural fractures opening at high pressures, causing increased leak-off. We used pure water instead of slickwater during stimulation and 100 mesh particles as proppants.

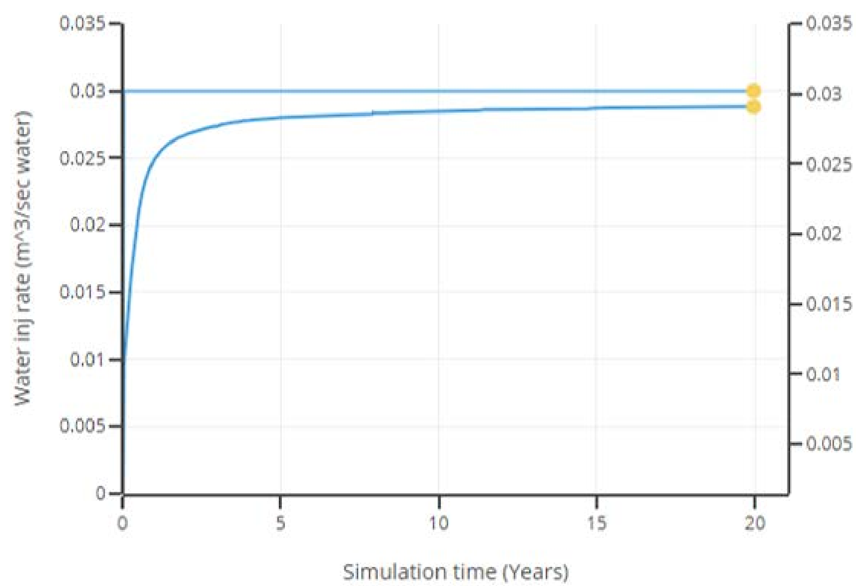
The production temperature for this design (Figure 8a) initially increases (due to diminishing wellbore heat losses) before dropping by about 5°C after 20 years. The production flow rate (Figure 8b) gradually increases to over 95% of the injection flow rate. Different designs such as a large wellbore field with alternating injection and production laterals may yield a smaller water loss rate. The injected proppant in all five fractures mostly settled in the bottom section of the fractures (Figure 8d), resulting in heat sweep of the hottest region of the fracture but also preventing fluid from accessing the entire fracture heat transfer area. Other treatments are currently being explored such as using proppants with smaller density or using slickwater instead of clean water during stimulation, which may result in a more uniform proppant distribution within the fractures. When simulating the same design with only 16 stages instead of 20 stages (i.e., 80 fractures instead of 100 fractures), the production temperature drops to 66°C after 20 years.

Table 2: Input parameters for preliminary base case design simulated with ResFrac.

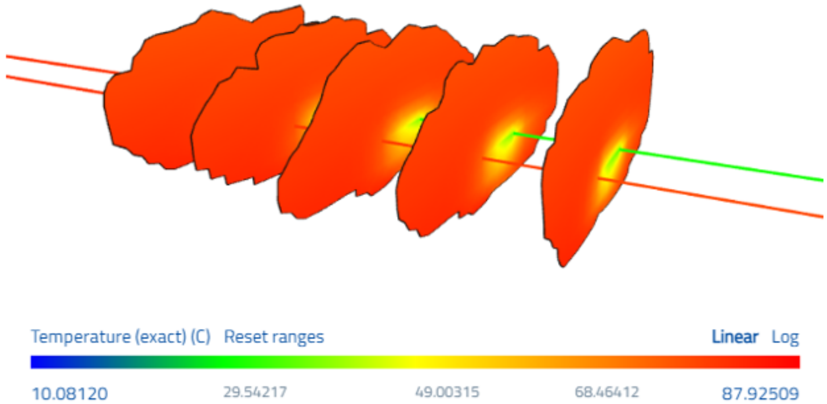
Parameter	Value
Vertical depth of laterals	3 km
Lateral spacing	150 m
Fracture spacing	20 m
Rock density	2,800 kg/m^3
Rock specific heat capacity	1,000 J/kg/K
Rock thermal conductivity	2.8 W/m/K
Rock porosity	3.9%
Rock permeability	10^{-19} m^2
Rock initial temperature	81°C at 3 km depth
Minimum horizontal principal stress $S_{h,min}$	72 MPa at 3 km depth
Maximum horizontal principal stress $S_{h,max}$	108 MPa at 3 km depth
Vertical stress S_v	80 MPa at 3 km depth
Initial pore pressure	32 MPa at 3 km depth
Young's modulus	31 GPa
Biot coefficient	0.58
Poisson's ratio	0.32
Horizontal fracture toughness	2.2 MPa-m$^{1/2}$
Vertical fracture toughness	3.3 MPa-m$^{1/2}$
Rock thermal expansion coefficient	0.00001 1/°C
$E_{0,max}$	0.00027 m
90% closure stress	17 MPa
$E_{res,max}$	0.000001 m
Total number of fracture clusters	100
Stimulation treatment	Both injection and production well stimulated with 4 clusters per stage and 4 perforations per cluster. Injection sequence: 1. 10 min at 0.1 m^3/s (no proppant) 2. 80 min at 0.25 m^3/s with proppant (90 kg/m^3) 3. 80 min at 0.25 m^3/s with proppant (150 kg/m^3) 4. 10 min at 0.05 m^3/s (no proppant).
Long-term fluid flow rate	30 L/s
Long-term fluid injection temperature	30°C


Wellhead temperature (model internal) (C)
100
90
80
70
60
50
40
30
20
0
5
10
15
20
Simulation time (Years)

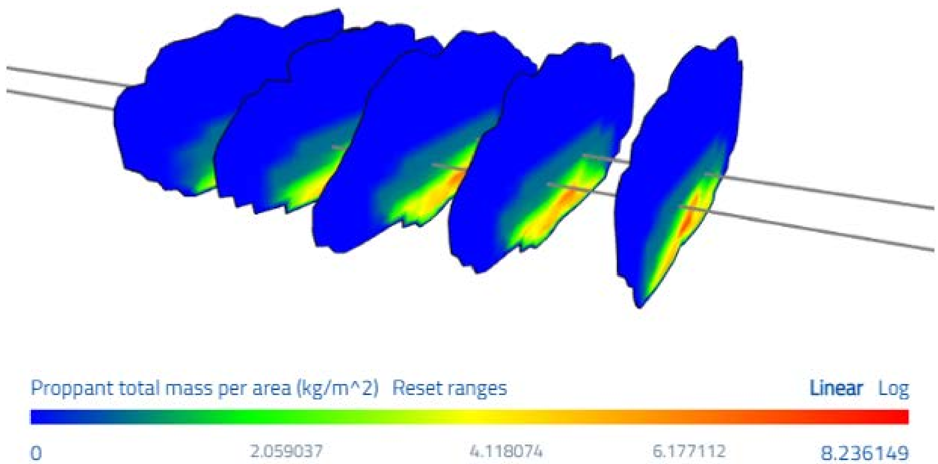
(a)


Water inj rate (m^3/sec water)
Water prod rate (m^3/sec water)
0.035
0.03
0.025
0.02
0.015
0.01
0.005
0
5
10
15
20
Simulation time (Years)

(b)



(c)



(d)

Figure 8: ResFrac Simulation Results. (a): Injection (orange) and production (purple) temperature profile; (b): injection and production flow rate (injection flow rate constant at 30 L/s); (c): fracture temperature distribution after 20 years; (d): proppant distribution after 20 years. Bottom figures have lateral extended by 10 times for better visibility of individual fractures.

6. Conclusions

In support of the Earth-Source Heat project at Cornell University, we conducted reservoir simulations to explore technical feasibility and design requirements of an EGS reservoir supplying 5 to 10 MW_{th} of heating to the university's district heating system. We applied three different simulators: (1) the thermal (T) Gringarten model, (2) the thermal-hydraulic (TH) FOXFEM simulator, and (3) the thermal-hydraulic-mechanical (THM) ResFrac simulator. We leveraged subsurface data obtained from the 3 km deep CUBO well drilled in 2022, including reservoir temperature, stress field, and thermo-physical properties.

Inspired by the recent EGS advancements, the EGS reservoir considered consists of an injection-production doublet at ~3 km vertical depth and ~2 km long horizontal laterals. The wells are spaced about 100 to 150 m apart and connected with a network of ~100 vertical parallel fracture clusters. The initial rock temperature is 80°C, and water as heat transfer fluid is injected at 20° to 40°C and 30 to 50 L/s. Lower injection temperatures would require utilizing a heat pump for integrating with the existing district energy infrastructure.

The key study outcome, supported by all three simulators, is that, depending on injection temperature and flow rate, an *effective* heat transfer area on the order of 2 to 3 km^2 is required to provide 5 to 10 MW_{th} of heating continuously over 15 years with limited thermal decline. This total heat transfer area can be obtained with ~100 to ~150 fracture clusters where each fracture has an effective heat transfer area on the order of 20,000 m^2. ResFrac simulations indicate that stimulating both wells that are spaced 100 to 150 m apart with injecting proppants is a potential stimulation treatment to obtain a sufficiently large effective fracture heat transfer area. Previous work has shown that with today's drilling costs, integrating this doublet system with a heat pump into the existing district heating network has a cost-competitive levelized cost of heat on the order of $40/MWh (assuming 4.25% nominal discount rate).

Simulations with FOXFEM and ResFrac allowed quantification of the difference between fracture dimensions and effective fracture heat transfer area, as certain zones of the fracture may not be accessed by the circulating fluid. Reasons include flow not reaching the outer edges of the fracture, and preferential pathways within the fracture due to large aperture regions (e.g., proppants settling in the lower zone of the fracture.

Planned future modeling work includes conducting additional reservoir simulations to further explore sensitivity to subsurface conditions, including considering reservoir heterogeneity, different reservoir depths, and different wellbore designs. Further in-situ subsurface characterization is planned by deepening the CUBO well, installing permanent fiber, and running additional logs, stress field tests and flow tests. Finally, planning and design of a first doublet with horizontal laterals combined with multi-zone stimulation to provide heating to the campus is ongoing.

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