

Techno-Economic feasibility of enhanced geothermal systems (EGS) with partially bridging Multi-Stage fractures for district heating applications

Pengliang Yu, David Dempsey, Rosalind Archer

Author's accepted manuscript (peer-reviewed, before publisher typesetting)

Published as: Yu, Pengliang, Dempsey, David, Archer, Rosalind (2022). Techno-Economic feasibility of enhanced geothermal systems (EGS) with partially bridging Multi-Stage fractures for district heating applications. Energy Conversion and Management, 257, 115405. <https://doi.org/10.1016/j.enconman.2022.115405>

Accepted manuscript. © 2022. This manuscript version is made available under the CC-BY-NC-ND 4.0 license <https://creativecommons.org/licenses/by-nc-nd/4.0/>. The version of record is available at <https://doi.org/10.1016/j.enconman.2022.115405>

Open copy, summary and machine-readable versions:
<https://ddempsey.github.io/papers/2022-yu-techno-economic-feasibility-enhanced-geothermal/>

Techno-Economic feasibility of enhanced geothermal systems (EGS) with partially bridging Multi-Stage fractures for district heating applications

Pengliang Yu^{a,c,*}, David Dempsey^b, Rosalind Archer^d

^a Department of Engineering Science, University of Auckland, Auckland, New Zealand

^b Department of Civil and Natural Resources Engineering, University of Canterbury, Christchurch,
New Zealand

^c Geothermal Institute, University of Auckland, Auckland, New Zealand

^d School of Engineering and Built Environment, Griffith University, Queensland, Australia

* Corresponding author at: Geothermal Institute, University of Auckland, Auckland, New Zealand.

E-mail address: pyu340@aucklanduni.ac.nz (P. Yu).

Keywords: Partially bridging fractures; EGS; Residential heating; Techno-economic analysis; Box-
Behnken design

Abstract

Here, we investigate the techno-economic feasibility of an enhanced geothermal system (EGS) for direct heating, using a new horizontal-well with partially-bridging fractures design. To do this, we developed numerical models to evaluate reservoir dynamics and output, economic performance and environmental benefits. This model was used to determine optimal thermal power output over a 20-year operation for given parameters. Then, we ranked the effects of key parameters on commercial and environmental outcomes. Stimulated reservoir permeability and reservoir temperature are the primary determinants of economic viability, with lesser effects due to reservoir depth and fracture number. A case study was developed for the Qiabuqia EGS, China, capturing uncertainty through sampling of a surrogate model. We show that a 14-fracture design was economically preferred, providing up to 2.8 km² of indoor heating over 20 years with considerable emissions offset (~ 1.5 Mt of CO₂) and economic benefit (24–185 M\$).

1. Introduction

Enhanced geothermal systems (EGS) are artificial geothermal reservoirs created by hydraulic fracturing and other stimulation techniques in ultra-low permeability formations. The goal is to create favourable conditions for water circulation and heat mining that support surface energy applications, e.g., district heating, electricity generation, or industrial direct heat use. In recent years, technological improvements in horizontal drilling and multiple-stage hydraulic fracturing have revolutionized economic gas production from low permeability shale [22]. It is hoped this technology could be used to engineer fracture networks with large surface area for EGS [20,23,38,41], although the high costs remain a significant challenge.

There have been numerous attempts at economic EGS creation since the 1970s. The Fenton Hill EGS in New Mexico [33,41] was the earliest attempt to extract heat from low permeability rock, deploying a new fracture design proposed by Gringarten et al. [13] (Fig. 1a). Multiple vertical hydraulic fractures were engineered to connect and circulate water between two deviated wells, thereby extracting heat from a 190 °C reservoir at 3500 m depth. Several EGS projects have also been undertaken in Europe [12,15], Australia [17] and Korea [47]. These have met mixed success with challenges from induced seismicity, connectivity, and economic viability. Another contemporary prospect is the Qiabuqia geothermal field, China, where drilling to 3.7 km depth has revealed a 236 °C reservoir [24,25]. This field is now undertaking reservoir stimulation tests, and evaluation of possible well layouts and hydrothermal production, and is a later focus of this study.

1.1. EGS fracture design

Engineering a high surface area fracture network is essential to EGS reservoir creation. One popular design centers on fracture creation between pairs of parallel horizontal injection and production wells. For example, the Gringarten model trialled at Fenton Hill envisages multiple stages of “fully-bridging” vertical hydraulic fractures that traverse the rock volume between the wells (Fig. 1a). Each fracture provides a direct pathway for the circulating fluid between the wells, allowing it to be conductively heated by contact with the fracture walls, or by advective heat exchange if the water exits into a secondary network and later re-enters the main fracture. Adding more fracture stages increases the total surface area across which heat is extracted. However, because of the strong

permeability contrast between fracture channel and wall rock, most of the injected water is limited to flow in the fracture channels. This limits the heat extraction zone and exacerbates premature thermal breakthrough [26,38,48]. In practice, permeability within a fracture may be heterogeneous, further prioritising some pathways over others. Other fast pathways could exist between fractures. We have not considered this effect here.

In contrast, a “partially-bridging” fracture design proposed in our previous study [48] could increase the flow of water away from the fracture (Fig. 1b). The basic principle is that cold water is injected into a subset of fractures that are connected only to the injection well. The other fractures are connected only to the production well and they alternate with the injection fractures in a comb pattern. Thus, water must pass through the reservoir volume between injection and production fractures, which could comprise a secondary fracture network or a porous media. Yu et al. [48] showed that rock volumes between fractures were subject to evolving thermoporoelectric stresses during operation, which may promote permeability enhancement. Thus, we refer to this volume of rock as the stimulated reservoir volume (SRV). Upon exiting the SRV into a production fracture, the heated water can leave the reservoir via the production well.

The stimulated reservoir volume (SRV) [29] is a concept used for unconventional reservoir stimulation performance, where complex network structures are created between the multiple fracture planes. The dimensions of the secondary fracture network stimulated during multi-stage hydraulic fracturing process can be approximated by the 3D volume of the microseismic-event cloud. As suggested by Yu et al. [48], this could grow further during production operations. The hydraulic fractures are here presumed to be vertical, which corresponds to an EGS project in either an extensional or strike-slip tectonic setting, where the minimum principal stress is horizontal.

The main difference between fully bridging (Fig. 1a) and partially bridging EGS designs (Fig. 1b) is that, for the latter, the injected water must sweep the SRV domain, which forces advective heat transfer through the bulk rock formation. This delays thermal breakthrough and results in more heat extraction over the operational lifetime, as demonstrated by the modelling study of Yu et al. [48]. In practice, creation of partially bridging fractures requires parallel injection and production wells that are both cased and then precisely perforated at alternating sites. This permits control over the dimensions of the SRV, which is bracketed by hydraulic fractures grown from the perforations. It is important the hydraulic fracture propagation stops short of the opposite well to

prevent accidental connection or damage to casing. Practically, this could be achieved by real-time microseismicity monitoring, which has been demonstrated for shale gas fracturing [8,45,50]. This could be problematic in the event that fully-bridging fractures are inadvertently created and some type of plugging solution was required. Permeability within a fracture may be heterogeneous, further prioritising some pathways over others. Other fast pathways could exist between fractures. We have not considered this effect here.

1.2. Economic assessment of EGS application

EGS is a promising source of stable, direct-use heat and has associated environmental benefits where fossil fuels are displaced. The World Bank Group [14] has outlined the importance of feasibility studies, and emphasizes the securing of financing, as well as environmental and social safeguards for geothermal electricity production.

(1) Electricity generation Most economic studies of EGS have focused on its feasibility for electric power generation. Several software packages have been developed to assist economic analyses of EGS. Early software (Tester et al., 2006) focused on sensitivity analysis of levelized electricity prices to drilling, plant, and stimulation costs. Later, this was modified [4] to include reservoir heat sweep.

A key element of feasibility is thermal and hydraulic performance of the reservoir, particularly water rate and temperature. For example, Augustine [2] proposed a methodology to calculate EGS electricity generation potential based on a Gringarten fracture model [13] which used an analytical solution to calculate the heat extraction from fractured rock. However, as a fully-bridging fracture design, this conceptual model may not fully utilize extractable heat from a given bulk rock volume. Others [25,46] have investigated economic feasibility, environmental benefits and electricity generation from reservoirs in China. However, most approaches have neglected uncertainties in model parameterization, which has downstream implications for financial risk.

(2) Direct-use There has been comparatively less research on the costs and benefits of EGS in direct use contexts (e.g. district heating networks, industrial heating). Beckers et al. [4,6] compared feasibility of EGS direct-use heat and electricity applications and found that electricity was only

economically competitive for medium- and high grade EGS projects, whereas direct-use can be cost-effective even for low-grade resources.

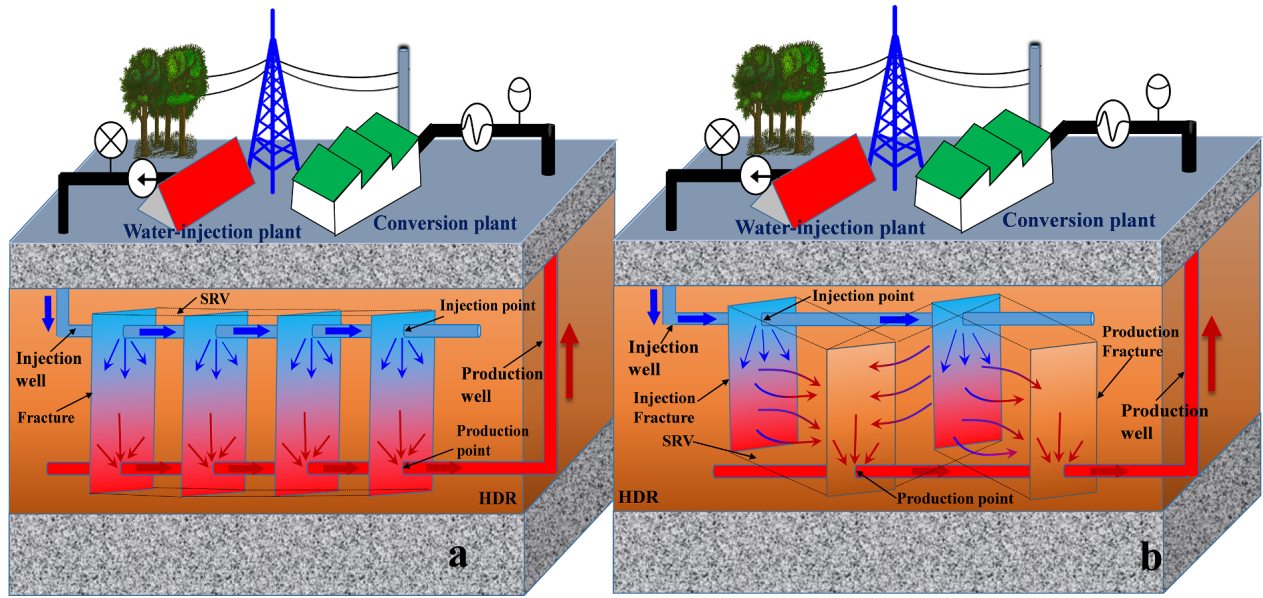


Fig. 1. Schematic diagram of EGS designs with paired horizontal injection and production well, and two fracture designs connecting them. (a) Fully-bridging hydraulic fractures, after Gringarten (1975) (b) Partially-bridging hydraulic fractures, after Yu et al. [48]. Arrows denote fluid flow pathways.

More recently, Beckers et al. [3] has evaluated techno-economic feasibility of geothermal direct use for campus heating applications, turbine cooling, and solar heat seasonal storage. The levelized cost of heat (LCOH) of these projects ranged between \$13 and \$350/MWh depending on financial incentives and assumed technology [5,30].

Huang et al. [18] presented an economic analysis of EGS heating in the Yitong Basin, China using a simplified single fracture model and found this to be uneconomical due to high drilling costs. However, such a fixed fracture geometry is restrictive and there is a need for research that explores the feasibility of multi-stage fracture designs that could improve heat extraction rates. Here, we explore the effect of reservoir parameters (initial temperature, reservoir depth, SRV permeability, fracture numbers etc.) on the economics of EGS that use partially-bridging fracture designs.

The total investment for a geothermal heating plant includes both subsurface costs, e.g., exploration, drilling and stimulation, surface plant infrastructure installation, operation and maintenance. Subsurface investment is a major capital cost influencing economic feasibility, e.g., drilling

and stimulation costs exceed 75% for medium- and low-grade EGS [28,41]. At the same time, surface operations include costs for heat exchange stations, land, pipelines, maintenance, management and personnel. Beckers et al. (2016; 2019; 2021) have summarized several capital and O&M cost correlations for various applications and geothermal reservoirs.

1.3. Methodological review

To explore optimal EGS reservoir design, it is necessary to identify parameters that constrain the longevity and profitability of a proposed project. In particular, we wish to maximize heat output – a product of temperature and flow rate – and reservoir lifetime while minimizing installation costs and the investment recovery period. Numerical modelling is used to predict heat and mass transfer processes in the reservoir and wellbore, and then integrate these with surface operation and financial systems. One challenge, however, is the trade-off between model complexity representing these processes and computational resources constraints when mapping parameter space uncertainty with a large number of simulations.

Experimental Design (ED) and Response Surface Methods (RSM) are one approach for addressing the complexity/uncertainty trade-off [10,43]. The complex model is used to simulate only a handful of parameter combinations that span the plausible space and then a fast surrogate model is constructed to replicate the output of the complex model. The surrogate model can be used to rapidly explore parameter space, either in an optimization loop or to quantify uncertainty. However, this approach is not without its drawbacks. Assessing the validity, reliability and replicability of the surrogate models is challenging, particularly while ensuring appropriate levels of sensitivity and accuracy with respect to the complex model. These issues are partially addressed by careful selection of the independent variables, and the ED-RSM methodology [32].

The hybrid complex-surrogate modelling approach has been adopted in both petroleum and geothermal reservoir engineering. Applications include uncertainty modelling [43], sensitivity studies [44], history matching [49], reservoir performance optimization and resource assessment [10]. Mishra et al. [31] compared classic factorial and sampling designs with several different response surface methods to build statistical predictive models of CO₂ sequestration performance. They showed that the Box-Behnken experimental design with a quadratic polynomial response surface performed well at predicting the simulations results for CO₂ injection into a reservoir-caprock system. Asai et al. [1]

developed surrogate models based on Box-Behnken experimental design for fully bridging fractures EGS design, which showed well spacing is the most important parameter in extracting heat from EGS. However, the other important factors (e.g., Initial reservoir temperature, reservoir depth, SRV permeability and fracture number) are not considered in their experimental design. Furthermore, no economic and environmental evaluation were assessed in their study.

In our view, one of the paramount challenges in any EGS project is the cost-effective engineering of subsurface fracture networks with large surface area. We have tackled this problem on two fronts: (1) by investigating exotic fracture designs and (2) assessing their economic performance. Partially-bridging fractures are used as an example, but other designs that maximize surface area or maintain high production temperatures would be alternative candidates. Numerical models, both physics-based and reduced-order proxies, provide a practical means of evaluating and optimizing these designs before field testing.

In this study, we develop a physics-based model for heat and mass transfer in an engineered reservoir and wellbore system that uses partially-bridging fractures. A binary search was used to determine the highest thermal power output that can be stably maintained over the project's operational lifetime, subject to the seasonal requirements of a district heating application. Then, the physics model is used to assess heat extraction performance across key parameter ranges. These results are used to develop a fast polynomial surrogate model using ED-RSM method. Finally, we use the surrogate model and Monte Carlo simulation to perform an economic and environmental evaluation for a case study EGS reservoir in Qiabuqia, China.

2. Physics-based EGS flow and fracture simulation

2.1. Conceptual model

We considered a horizontal doublet-well system in which the primary flow network comprises a series of vertical fractures in a partially-bridging design that delineate a number of SRVs. We set the size of the computational domain to $2000 \times 500 \times 300$ m centered at a specified reservoir depth (ranging from 1 to 5 km). The domain is subdivided into an unstimulated reservoir zone enclosing separate SRV and fracture zones, as well as injection and production well zones with associated perforations that provide flow linkages between fractures and wells. Vertical fractures are evenly distributed

between the toe and heel of the wellbore.

Water is injected into the injection wellhead where it flows along the wellbore and through perforations into the injection fractures. From there, it flows across the SRV zones becoming heated as it equilibrates with the rock matrix. Water exits into the production fractures and from there into the production well via the perforations, exiting at the production wellhead (Fig. 1). Geometric parameters of the reservoir-fracture-well model are listed in Table 1.

2.2. Governing equations

Our physics-model is constructed using the thermal groundwater simulator Finite Element Heat and Mass transfer (FEHM) [53]. To simplify calculations, we represent the EGS reservoir zone and SRV zone as an equivalent continuous porous medium with homogeneous and isotropic properties [11]. Furthermore, local thermal equilibrium is assumed between the solid rock and fluid [40], which means thermal short circuiting via fast flow pathways in the SRV cannot be considered. FEHM solves heat and mass balance equations subject to Fourier and Darcy laws using a control volume method. Mass conservation for fluid flow in a porous media is expressed [21]:

Table 1
Geometric parameters of the reservoir-fracture-well model.

Parameters	Values
Model dimensions (m ³)	2000 × 500 × 300
Reservoir depth (m)	range from 1000 to 5000
Fracture numbers	range from 4 to 20
Fracture aperture (mm)	1 [39]
Fracture width (m)	300
Fracture height (m)	30
Well spacing (m)	300

$$\frac{\partial}{\partial t}(\rho_w \varphi) + \nabla \cdot \mathbf{q} = Q_m \quad (1)$$

where φ is rock porosity, Q_m is the mass source term. ρ_w is pressure and temperature-dependent fluid density, and $\mathbf{q}$ is the Darcy flux, expressed:

$$\mathbf{q} = -\frac{k}{\mu}(\nabla p + \rho_w \mathbf{g}) \quad (2)$$

199 where k is permeability, μ is viscosity, p is pressure, $\mathbf{g} = [0, 0, -g]$ is the gravitational acceleration
 200 vector.

201 The cubic law is used to assign permeability in the fractures [52]:

$$k = \frac{a_f^2}{12} \quad (3)$$

202 where a_f is the fracture aperture. Fracture permeability calculated by the cubic law is represented
 203 as an equivalent fracture permeability [27] in FEHM:

$$k_e = \frac{k a_f}{a_{fe}} \quad (4)$$

204 where k_e is the equivalent fracture permeability, a_{fe} is the control volume width of fracture zone
 205 nodes in FEHM.

206 The energy conservation equation is formulated [54]:

$$(\rho c_p)_{eff} \frac{\partial T}{\partial t} + \nabla \cdot (\rho_w c_{p,w} \mathbf{q} T) - \nabla \cdot (\lambda_m \nabla T) = Q_E \quad (5)$$

207 where T is temperature, Q_E is the energy source term, $c_{p,w}$ is the heat capacity of fluid. $(\rho c_p)_{eff}$
 208 and λ_m are effective volumetric heat capacity and thermal conductivity, calculated as [54]:

$$(\rho c_p)_{eff} = (1 - \varphi) \rho_s c_{p,s} + \varphi \rho_w c_{p,w} \quad (6)$$

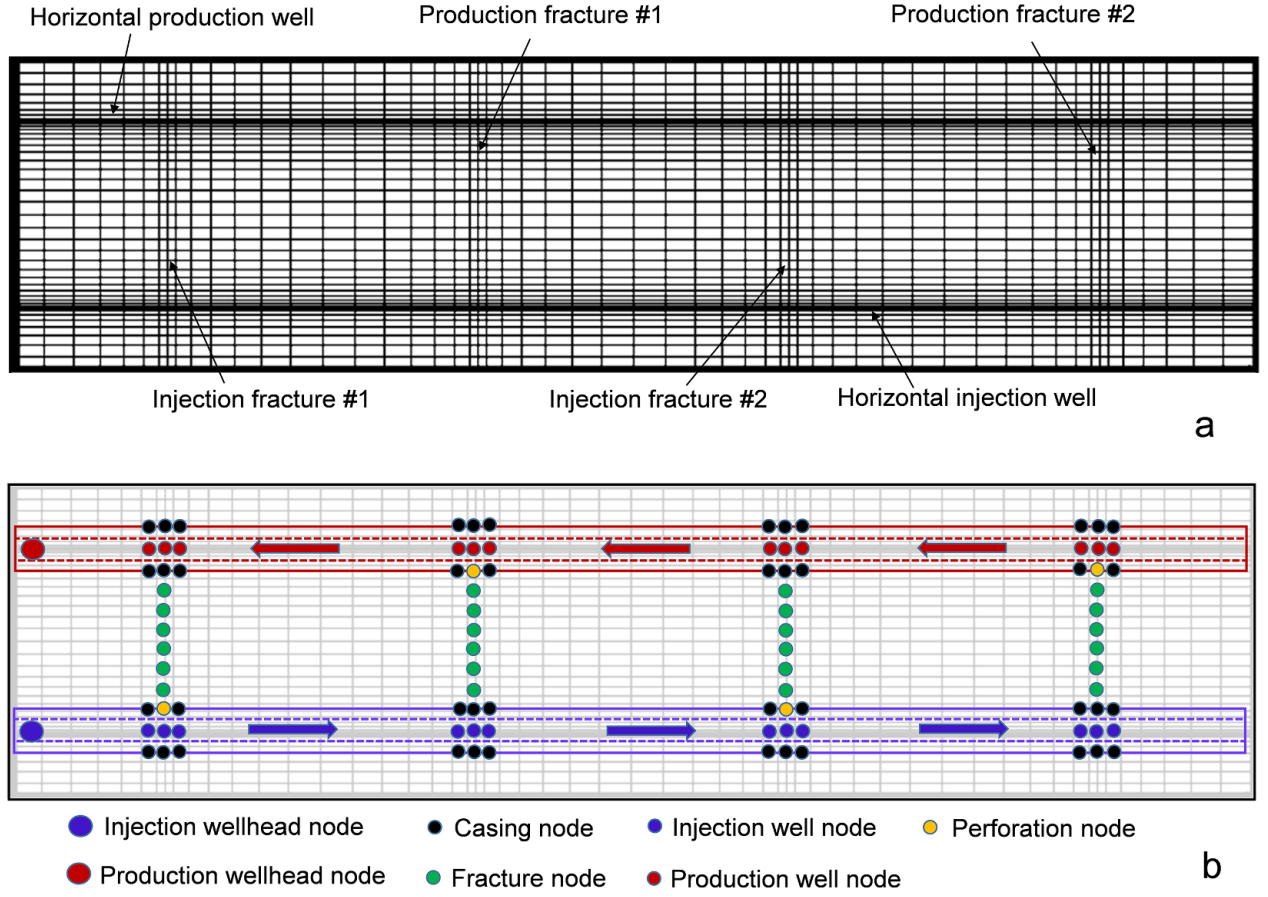


Fig. 2. (a) x-y plane view of model mesh for four partially-bridging fracture model and (b) a schematic diagram of node assignments and connections in the FEHM framework. Mesh spacings are indicative only.

Table 2						
Physical parameters of reservoir-fracture-well model.						
Parameters	Background rock	SRV	Fracture & perforations	Wellbore	Casing	
Density (kg/m ³)	2500	2500	—	—	2500	
Heat conductivity (W/(m·K))	2.5	2.5	—	—	2.5	
Heat capacity (J/(kg·K))	1000	1000	—	—	1000	
Porosity (%)	1	2	100	100	0	
Permeability (m ²)	10 ⁻¹⁶	10 ⁻¹⁶ ~ 10 ⁻¹⁴	$a_f^2/12$	5×10^{-9}	10 ⁻¹⁸	
Reservoir temperature (°C)	range from 100 to 300					

$$\lambda_m = (1 - \varphi)\lambda_s + \varphi\lambda_w \quad (7)$$

209 where ρ_s , $c_{p,s}$ and λ_s are the density, heat capacity and thermal conductivity of the solid rock,
210 respectively.

211 **2.3. Horizontal wellbore model**

212 The purpose of the wellbore model is to capture heat extraction and mixing processes in long well-
213 bores with multiple perforations allowing fluid to exit into, or enter from, the reservoir. This means
214 that, instead of specifying fixed, proportioned injection rates and temperatures for the individual
215 fractures, we specify a single injection temperature, and rate or pressure at the wellhead. Simi-
216 larly, we specify a single production pressure and place no specific restrictions on flows exiting the
217 production fractures into the wellbore.

218 The wellbore model is built in FEHM by assignment of node properties (Fig. 2) to represent the
219 horizontal wellbores, casing, and fracture perforations located along the wellbore boundary [11]. Well
220 nodes are assigned 100% porosity and high permeability, while the casing is impermeable and has
221 zero porosity. Perforation nodes are assigned the same permeability and porosity as the fractures.
222 Representative parameters for reservoir and wellbore simulators are listed in Table 2. We also note
223 that this simplified representation of the wellbore is not able to capture turbulence or other losses
224 that can occur in wells.

225 **2.4. Initial and boundary conditions**

226 The reservoir's initial temperature was assigned a value in the range 100 to 300°C depending on the
227 assumed depth and geothermal gradient. Initial fluid pressure was assumed to be hydrostatic and
228 calculated as $p_i = \rho_w g z$, where z is the reservoir depth and varies between 1000 and 5000 m. All
229 model boundaries were closed to heat and mass flow because stimulation operations are assumed to
230 create a flow network that limits water loss.

231 Fluid with an initial temperature of 30 °C [39,42] was injected at the wellhead node of the
232 injection well. The initial injection rate is 500 kg/s, and the injection rate is constrained so that a
233 maximum injection pressure is not exceeded at any time during the simulation. The maximum pump
234 injection pressure is equal to the minimum principal stress, which is designed to avoid propagation of
235 hydraulic fractures in the reservoir. The minimum principal stress is calculated assuming a critically-
236 stressed crust limited by Mohr-Coulomb frictional failure in a normal faulting environment. Thus,

237 p_{max} is given by Jaeger et al. [19]:

$$p_{max} = (\sigma_v - p_f) \left(f_s + \sqrt{1 + f_s^2} \right)^{-2} + p_f \quad (8)$$

238 Where σ_v is the vertical stress, computed as $\rho_s g z$, and f_s is the rock friction coefficient, assigned a
 239 typical value of $f_s = 0.6$ in this study. For example, at a depth of 3000 m, p_{max} is 43.54 MPa, while
 240 the initial reservoir pressure p_f is 29.4 MPa. This means that fluid pressure increase of 14.14 MPa
 241 is permissible.

242 The minimum outlet pressure at the wellhead of the horizontal production was 5 MPa lower than
 243 the reservoir initial pressure, which is low enough to ensure that fluid is not generally flashed in the
 244 wellbore. The actual outlet pressure was calculated dynamically to meet a heat delivery target.

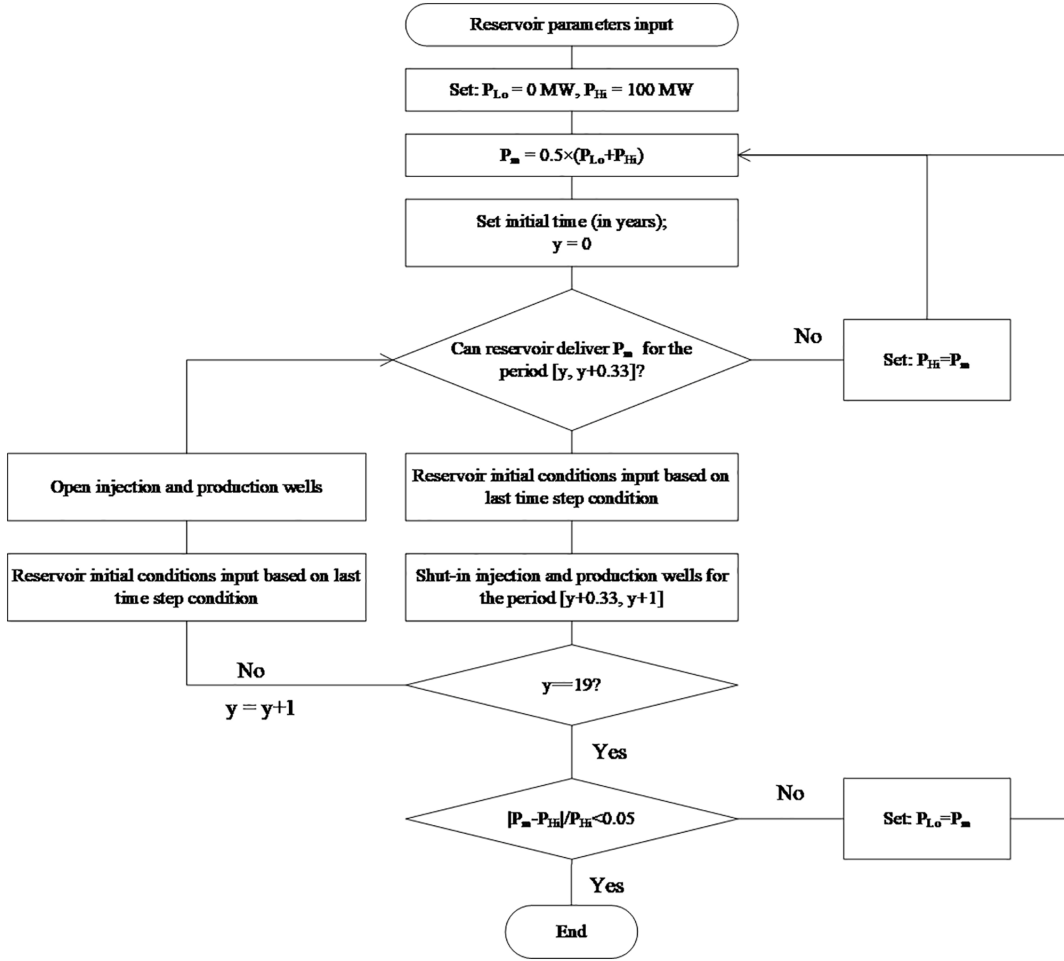


Fig. 3. Simulation framework for binary search. y = integer counter for year. $[P_{Lo}, P_{Hi}]$ = current binary search bounds. P_m = mid-point of binary search.

2.5. Stable, seasonal heat output

District heating schemes do not need to operate throughout the year and we therefore subdivided each year into either heating or shut-in stages. Furthermore, delivery of a stable, constant heat output during heating stages, across the entire lifetime of the modelled project, is an additional constraint we have imposed in our study. We enforced this by increasing the production flow rate as temperatures in the system begin to decline. In a real operation, seasonal demand could vary in a manner that may or may not be anticipated, however, we deemed it attractive that, at least at an early design stage, an achievable baseload power was estimable.

To model stable, seasonal heat output, we used a simulation framework that wrapped a decision model inside an optimization loop (Fig. 3). At the lowest level, a production flow rate is evaluated at each time step based on the production wellhead temperature in FEHM. Internally, an outlet pressure is computed that returns a flow volume meeting the heat delivery target, ΔQ for that time step, allowing for a brine rejection temperature of 35 °C:

$$\Delta Q = q(P_o)\Delta t (h_o - h_{35}) \quad (9)$$

where $q(P_o)$ is the outlet pressure dependent flow rate, Δt is the time step length, h_o is the specific enthalpy of fluid at the outlet, and h_{35} is the specific enthalpy of the fluid at rejection. Thus, the production well behaviour is fully specified by three parameters: the rejection temperature, the heat delivery target, and a minimum outlet pressure, with the latter used to prematurely terminate the model if the heat demand exceeds the delivery capacity of the EGS.

We modelled a 20 year period of EGS operation to allow a return on investment. Heat stages were assumed to last 120 days followed by 240 days of shut-in, approximating one year of operation. Note that we only considered the seasonal heating application in our research. There are other heating industrial applications that could operate year-round and would not require well shut-in. In addition, hybrid applications that involve heating and electricity generation could also be evaluated using this model.

A binary search method was used to estimate the maximum deliverable power output for a given set of reservoir parameters and subject to maximum injection pressure and minimum production pressure control. The stopping condition for the search was when the update was smaller than

5% (i.e., $|P_m - P_{Hi}|/P_{Hi}$ less than 0.05, where P_m is the current heat power guess and P_{Hi} is the
previous). The initial search interval was [0,100] MW in all cases. FEHM time-stepping increases
and decreases adaptively to maintain estimated relative error at each time-step less than 0.1%.

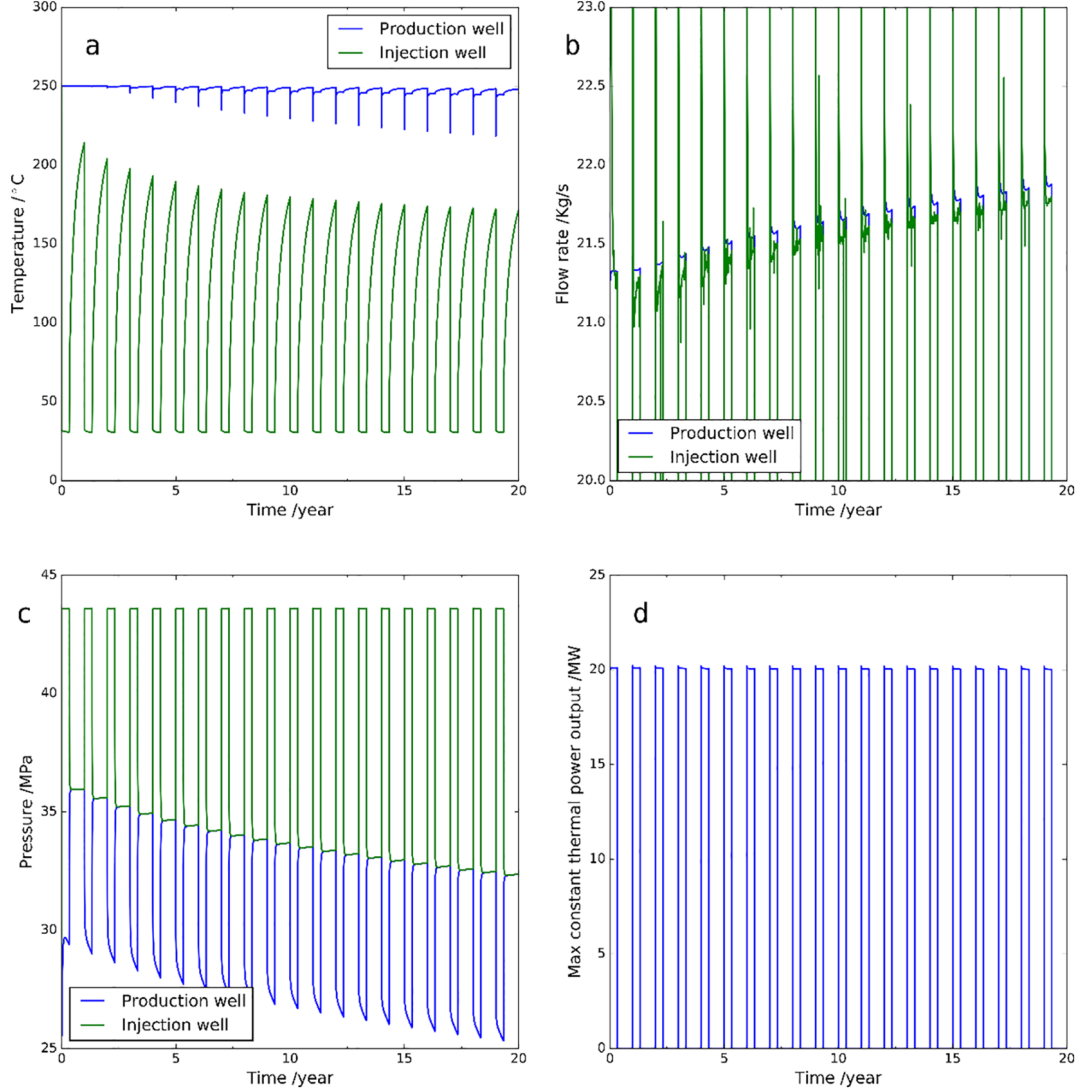


Fig. 4. Summary of modelled EGS time series: injection (green) and production (blue). (a) Temperature, (b) flow rate, (c) pressure of injection and production well, and (d) thermal output over the 20-year production. Note, in (b), the injection rate and production rate are zero during well shut-in periods (not shown). Some instability at early time during restarted operation is apparent.

2.6. Model behaviour

Before using this model to develop a surrogate via ED and RSM, it is useful to first check its general behavior. This includes, the injection and production flows that ensure delivery of a stable heat

output and the accompanying thermal evolution in the fractured reservoir. To this end, we ran a model with four partially bridging fractures located at a depth of 3000 m (Fig. 1(b)), i.e., two injection and two production fractures enclosing three SRV zones and bookended either side by two more. The initial reservoir temperature is 250°C and the SRV is assigned a permeability of 3 mD. All other parameters in this benchmark model are listed in Tables 1 and 2. The simulation time is 20 years with injection and production wells operating in the first 120 days of each year.

Wellhead inlet and outlet time series (Fig. 4) illustrate annual oscillations due to heating/shut-in stages as well as long-term reservoir evolution. For example, temperature at the injection inlet is 30°C during operation but then rapidly reheats during shut-in (although not enough to recover the initial 250°C). Production temperature is generally stable at early time and then decreases as the reservoir cools (notwithstanding small recoveries during shut-down stages). The decreasing production temperature is offset by increasing injection and production rates with the latter facilitated by a steadily declining production outlet pressure. Overall, a 20 MW heat output is maintained over the 20 year simulation period. The mesh resolution sensitivity analysis results show good convergence with grid resolution and only minor increases in accuracy beyond our selected resolution. Additional description of temperature and pressure evolution at various locations in the reservoir over its 20-year lifetime are given in Supplementary Material.

3. Economic and environmental assessment

In this section, we introduce an economic analysis model that considers the total subsurface investment cost of a modelled EGS project as well as its financial performance and investment return. This is paired with an environmental benefits evaluation comprising an estimate of the displaced CO₂, SO₂ and NO_x emissions had coal instead been used to deliver the same heat output. Then, we explore the sensitivity of these metrics to key reservoir parameters including initial reservoir temperature, SRV permeability, fracture number and reservoir depth. Later, we apply an ED-RSM method to develop a polynomial surrogate model that can be used for optimisation or uncertainty analysis. Finally, we apply the surrogate model to an EGS direct-heat case study at Qiabuqia, China, evaluating the economic and environmental benefits of such a scheme.

3.1. Economic and environmental model

The economic evaluation model of this study considered the capital costs ($C_{capital}$), and operation and maintenance (O&M, $C_{O\&M}$) costs for an EGS direct-heating project. The EGS capital cost consists of exploration ($C_{exploration}$), drilling and completion ($C_{drilling}$), reservoir stimulation ($C_{stimulation}$) and surface plant (C_{plant}) costs (Beckers 2016).

$$C_{Total} = C_{capital} + C_{O\&M} \quad (10)$$

$$C_{capital} = C_{exploration} + C_{drilling} + C_{stimulation} + C_{plant} \quad (11)$$

where C_{Total} is the total investment of EGS project for direct-use application. Beckers (2016) summarized the costs of annual O&M, exploration, surface plant etc. for Low-, Medium-, and High-Grade EGS scenarios referring to direct-use under Today's, Mid-term, and Commercially Mature technologies. In this study, we adopted the average annual O&M costs and exploration investment for these three EGS grades under the Mid-Term technology and direct-use EGS scenarios. Specifically, $C_{O\&M} = 2.23M\$/year$ multiplied by the plant lifetime, and $C_{exploration} = 4.7M\%$ are used in the economic evaluation model. To estimate drilling and completion costs for both wells, we used the model of [28,35]:

$$C_{drilling} = 1.72 \times 10^{-7} \times MD^2 + 2.3 \times 10^{-3} \times MD - 0.62 \quad (12)$$

Where $C_{drilling}$ is expressed in million U.S. dollars (M\$) and MD is the measured depth of the well in metres, which is expressed as the sum of reservoir depth and horizontal wellbore length in our model.

For the stimulation cost of an EGS, most prior studies have estimated a fixed value between 0.5 and 1.2 M\$ [16,34,36]. However, these values were independent of reservoir depth and assumed a deviated or vertical geothermal well stimulation, which may not be applicable for multi-stage hydraulic fracturing in a horizontal well. Based on these fracturing costs on EGS stimulation operation, we elected to use 0.75 M\$ per fracture stage in this study.

$$C_{stimulation} = 0.75 \times F \quad (13)$$

where F is the number of hydraulic fractures. Thus, in our model, both development costs and heat output are increased for larger fracture designs, and adding more fractures does not necessarily improve a project's economic prospects. Of course, these cost models are subject to considerable uncertainty given the challenges of developing in hot, hard rock, and we acknowledge that updates are likely to be needed as more experience is gained. The surface plant equipment cost for direct-use heat mode are estimated based on the correlation that Beckers (2016) built in GEOPHIRES:

$$C_{plant} = 1.5 \times 10^{-4} \times W \quad (14)$$

where C_{plant} is expressed in million U.S. dollars (M\$). W is the thermal output in kW .

Based on the group heating principle, heat consumption per year is expressed [55]:

$$Q_h = \eta N q_h \left(\frac{T_{in} - T_m}{T_{in} - T_{out}} \right) \quad (15)$$

Where Q_h is the heat consumption per year per unit heating area, $J/yr/m^2$; η is the conversion factor between days and seconds (86400 s per day), N is length of the heating period in a year, days/yr; q_h is the heating area heat index (Heat load per unit area), W/m^2 ; T_{in} is the indoor design air temperature for heating, $^{\circ}C$; T_m is the average outdoor air temperature during the heating period, $^{\circ}C$; T_{out} is the outdoor design air temperature for heating, $^{\circ}C$. Based on the design code for a district heating network in China [56], the values for Qiabuqia used in this study are listed here: $q_h = 40$ W/m^2 [57], $N = 120$ days; $T_{in} = 20^{\circ}C$; $T_m = -1.6^{\circ}C$; $T_{out} = -9^{\circ}C$. The value of heating per heating season per unit heating area is $\$7.14 /yr/m^2$. The corresponding heat price expressed at $\$/MWh$ is 62.85 $\$/MWh$.

The maximum constant power output maintainable for 20 years for a given set of reservoir parameters is obtained from FEHM. Set alongside Q_h , this is used to obtain the possible heated area each year and hence the total income when multiplied by the price per year per unit heated area.

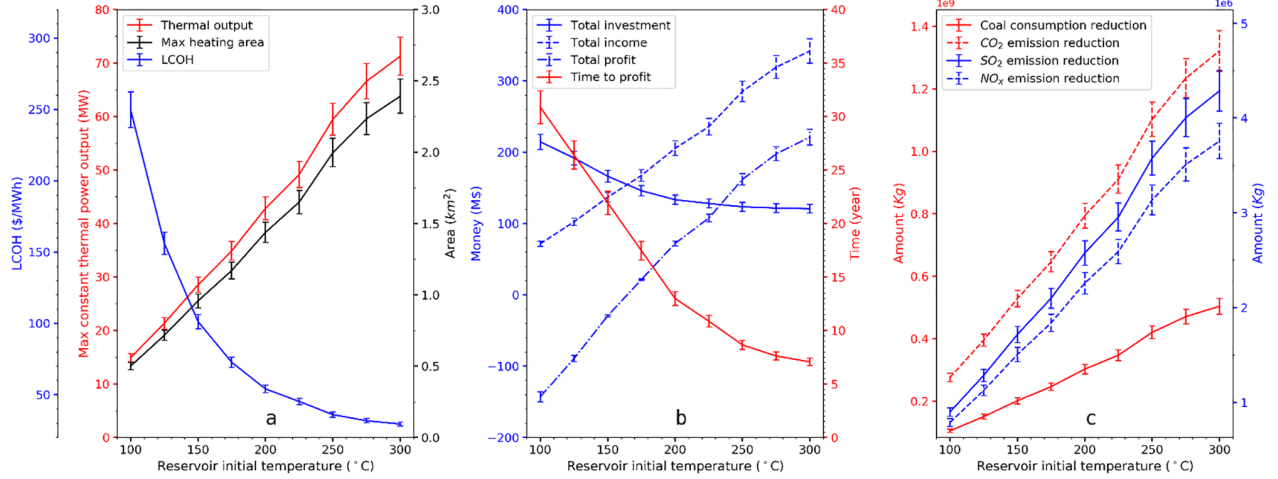


Fig. 5. (a)-(b) Economic and (c) environmental model outputs for a range of initial reservoir temperatures.

For simulations where profit is not realised in 20 years, we extrapolated current levels of production to estimate when profitability is achieved. In practice, because reservoir heat production is only optimized for the first 20 years, output would start to wane afterward and profitability may take even longer.

Finally, we assumed an annual interest rate of 5.48% on a loan taken for the total investment cost for given project parameters, i.e., depth and fracture count. This is used to compute the time taken for the project to first return a profit, which assumes that heating income is used to pay loan interest and principal at the maximum rate. Therefore, the return on investment is computed:

$$P = I_{Total} - C_{Total} \quad (16)$$

where P is the total profit of project, I_{Total} is the total income during 20 years operation, and C_{Total} is the total investment. Another techno-economic parameter for evaluating the feasibility is the levelized cost of heat (LCOH) based on the Eq.17 (Beckers, 2016):

$$LCOH = \frac{C_o + \sum_{i=1}^t \frac{C_i}{(1+r)^i}}{\sum_{i=1}^t E_i} \quad (17)$$

where C_o is the capital investment of the project (M\$), C_i is the annual operating and maintenance cost in year i (M\$/yr), E_i is the annual heat production in MWh/yr. As we modelled the maximum stable thermal output in our FEHM numerical model, no discount rate applies to annual heating production. r is the discount rate, which is calculated from the annual interest rate. The envi-

ronmental benefits analysis focuses on the equivalent coal consumption displaced by EGS heating and its attendant greenhouse gas emissions (CO_2 , SO_2 , NO_x). We used a conversion factor of 1 kg standard coal releasing 7000 kcal of heat [9] to compute the total mass of coal saved in the 20 years production lifetime. Further, the total emissions reduction was calculated using a conversion factor of 1 tonne of standard coal under combustion releasing 2620 kg CO_2 , 8.5 kg SO_2 , and 7.45 kg NO_x . The carbon tax and dust emission reduction are not formally considered in the cost analysis, although some ballpark figures are provided later.

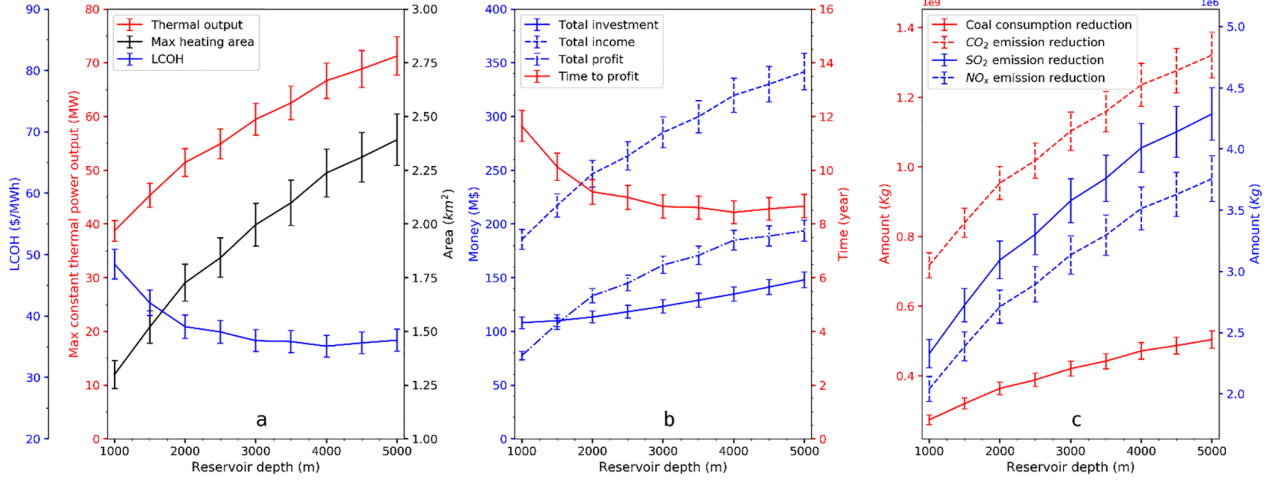


Fig. 6. (a)-(b) Economic and (c) environmental model outputs for a range of reservoir depths.

3.2. Sensitivity analysis

Initial reservoir temperature, depth, SRV permeability and fracture number were identified as key parameters likely to influence the economic prospects and the scale of environmental benefits of the proposed EGS. Notably, the reservoir temperature is determined by both reservoir depth and temperature gradient. Therefore, both reservoir temperature and reservoir depth are analysed in this study independently, particularly as depth controls safe fluid operating pressures that avoid unwanted fracturing. Fracture permeability was not considered because, as a high permeability pathway in the flow network, this value has a much smaller impact on reservoir performance compared to the main flow bottleneck (the SRV). Here, we have conducted a few indicative parameter sweeps to understand their relative importance. The benchmark reservoir parameters used are initial reservoir temperature (250°C), reservoir depth (3000 m), SRV permeability (3mD), and fracture count (10). Other parameters are listed in Tables 1 and 2.

(1). Initial reservoir temperature Notwithstanding the engineering challenges of high temperatures, hot reservoirs are generally more desirable because the produced water has a higher energy content. Depending on permeability, this can sustain a higher flow rate and power output over a fixed time horizon or, if flow limits are encountered, a longer lifetime before thermal breakthrough occurs. Our sensitivity study indicates roughly linear improvements in thermal output and heated area, and projects larger profits with increasing temperature (Fig. 5a, Fig. 5b), with similarly linear behaviour in the main environmental offsets (Fig. 5b). The LCOH decreases dramatically with the increases of the reservoir initial temperature because higher temperatures produce higher thermal outputs (Fig. 5a). The computed range of LCOH falls in the range computed by Beckers et al. [3] (\$13 to \$350/MWh) based on an analysis of five US geothermal deep use projects.

Because interest costs change depending on profit and repayment time scale, the total investment is not constant for different reservoir temperatures. Time to profit is inversely proportional with temperature, reflecting the approximately fixed project costs but increasing profitability. However, the project is not profitable over a 20 year production lifetime for reservoir temperatures less than 120°C because the subsurface investment cannot be recouped. The optimal outcomes are achieved for the highest considered temperature (300 °C) including profit of 210 M\$ and coal offset of 5×10^8 kg. The offset CO₂ emissions of 1.3×10^9 kg would be worth 5 M\$ at a carbon price of 10 \$/tonne, and 50 M\$ at a price of 100 \$/tonne.

(2). Reservoir depth If temperature is fixed, then the primary effect of reservoir depth is to control the maximum injection pressure that can be operated while avoiding hydraulic fracture propagation. Operating at higher injection pressures allows increased flow throughput for fixed permeability. Our sensitivity analysis indicates that thermal output, residential heating area, and profitability all increase for deeper reservoirs (Fig. 6). However, there are diminishing returns with increasing depth reflecting the quadratic cost of drilling with depth (Eq.12). The LCOH is also reduced for deeper reservoirs, which indicates that the increased thermal output outweighs the increased drilling costs. The time to achieve profit as a minimum at about 8.5 years and a depth of 4000 m. Offset coal and emissions increase in a diminishing manner matching thermal output. In practice, higher reservoir temperatures, and lower ambient or stimulated permeability conditions could reasonably be expected with increased depth.

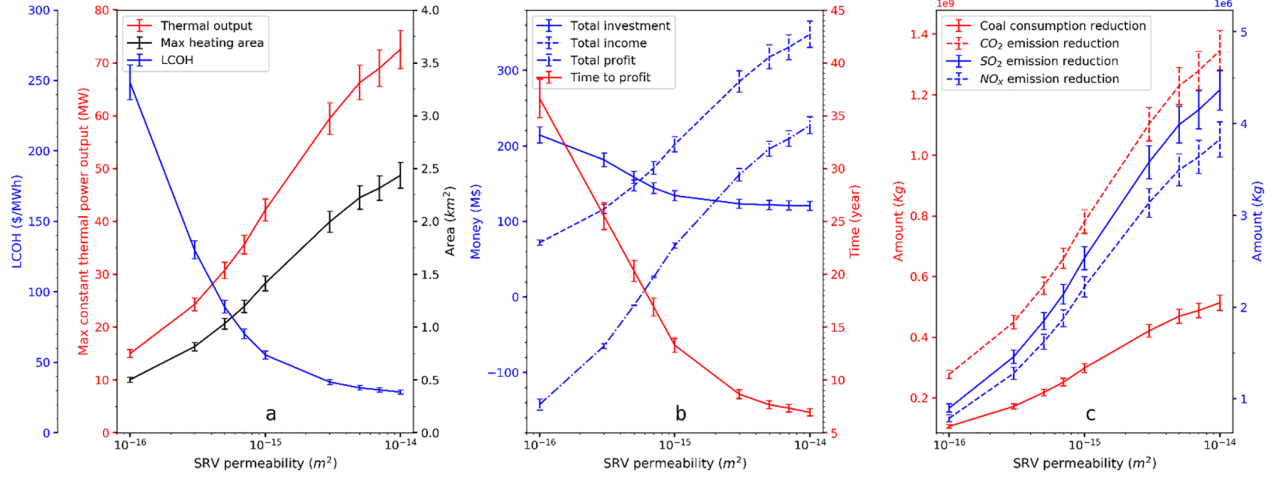


Fig. 7. (a)-(b) Economic and (c) environmental model outputs for a range of SRV permeabilities. For simulations where profit is not realised in 20 years, we extrapolated current levels of production to estimate when profitability is achieved. In practice, because reservoir heat production is only optimized for the first 20 years, output would start to wane afterward and profitability may take even longer.

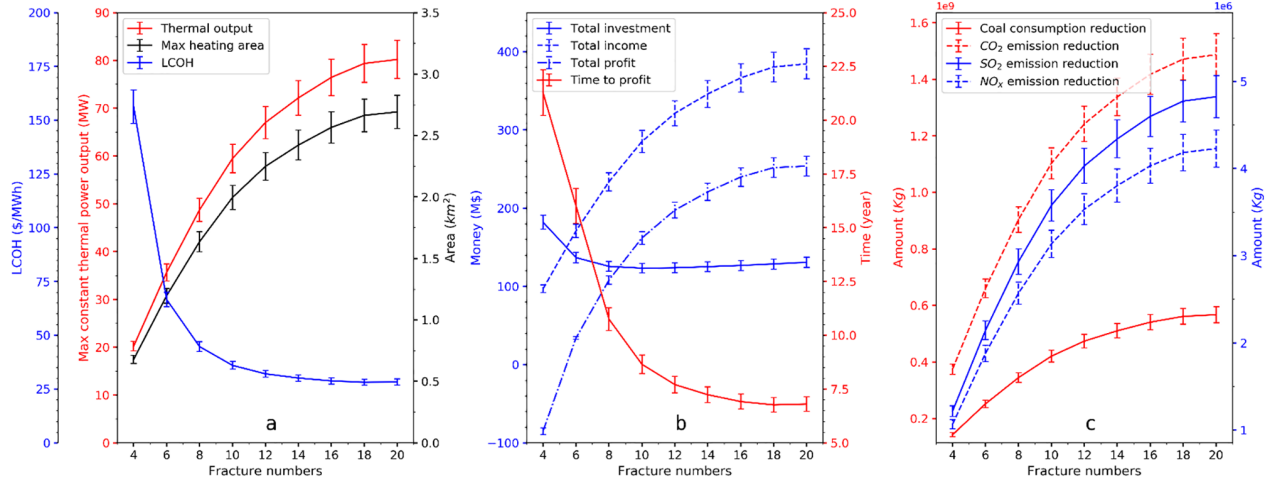


Fig. 8. (a)-(b) Economic and (c) environmental model outputs for a range of fracture numbers.

(3). **SRV permeability** Changing SRV permeability causes attendant changes in injection and production rates because these operate under fixed pressure conditions. Higher SRV permeabilities increase all desirable outcomes including thermal output, heated area, profitability and environmental offsets (Fig. 7). Similar with reservoir depth, SRV permeability is a strong control on LCOH significantly ranging from 30 \$/MWh to 250 \$/MWh. The total investment decreases with increasing SRV permeability because the project is more profitable and loans are paid back sooner, thus

reducing interest costs. For these parameters, projects are not profitable for an SRV permeability less than 0.4 mD. This highlights an essential role for secondary stimulation mechanisms outside of the hydraulic fracturing treatment that creates the network backbone.

(4). Fracture numbers Because our model assumes a fixed length for the horizontal wells, the addition of more fracture stages increases the number of inlet and egress points for water in the reservoir but not the volume of swept rock. Thus, the SRV volume to fracture ratio is reduced meaning that water takes a shorter pathway through the rock and is consequently heated less. Although increasing the fracture count improves most of the metrics of interest, diminishing returns become particularly severe at high counts ~ 16 – 20 (Fig. 8). At this extreme, both mounting stimulation costs and an almost flat marginal thermal output impact the bottom line. Clearly, careful thought should be put into the optimal number of fracture stages per length of wellbore.

The minimum time to profit is about 6.75 years when EGS reservoir has 18 fractures with the maximum profit of 250 M\$. As before, offset coal and emissions all scale with thermal output. LCOH decreases sharply with the increase of fracture numbers first, then reduces only slightly for fracture numbers larger than 12, due to the diminishing effect between thermal output and total investment.

3.3. Surrogate model

Initial reservoir temperature, reservoir depth, SRV permeability and fracture number each play a different role in the economic and environmental outcomes of the modelled EGS project. Understanding the interactions between these parameters is necessary if we wish to accelerate optimization strategies or quantify uncertainty across multiple parameters. To avoid the high computational costs associated with each simulation – several days depending on the particular parameters, FEHM and binary search convergence – we used ED-RSM to develop a surrogate model that is rapid to evaluate.

(1) ED-RSM design selection In experimental design, several parameters are varied simultaneously based on a predefined pattern. The goal is to obtain as much information as possible from the least amount of data using a minimal number of simulations (White et al. 2001a). Experimental design configurations can be categorized into two methods: sampling designs and factorial designs.

Table 3
Parameter values and levels for the Box-Behnken design.

Parameters	Units	Level		
		−1	0	1
Reservoir initial temperature (T_i)	°C	100	200	300
Reservoir depth (D)	m	1000	3000	5000
SRV permeability (K_{srv})	md	0.1	1	10
Fracture numbers (F)		4	12	20

Table 4
The Box-Behnken design and simulation results.

ID	Reservoir initial tem- perature (°C)	Reservoir depth (m)	SRV perme- ability (md)	Fracture numbers	Max. con- stant thermal power out- put -simulation	Max. con- stant thermal power out- put -predicted	Residuals (MW)
1	−1	−1	0	0	5.893	5.443	4.50×10^{-1}
2	1	−1	0	0	34.674	34.289	3.85×10^{-1}
3	−1	1	0	0	13.620	12.580	1.04
4	1	1	0	0	73.243	72.429	8.13×10^{-1}
5	−1	0	−1	0	2.852	3.087	-2.36×10^{-1}
6	1	0	−1	0	25.902	28.048	−2.15
7	−1	0	1	0	23.837	23.800	3.66×10^{-2}
8	1	0	1	0	95.134	95.010	1.24×10^{-1}
9	−1	0	0	−1	1.801	1.899	-9.77×10^{-2}
10	1	0	0	−1	16.450	16.194	2.55×10^{-1}
11	−1	0	0	1	18.551	19.079	-5.29×10^{-1}
12	1	0	0	1	84.485	81.144	3.34
13	0	−1	−1	0	8.307	8.165	1.42×10^{-1}
14	0	1	−1	0	12.713	14.050	−1.34
15	0	−1	1	0	46.063	42.200	3.86
16	0	1	1	0	68.910	70.990	−2.08
17	0	−1	0	−1	4.352	4.740	-3.88×10^{-1}
18	0	1	0	−1	8.875	8.596	2.79×10^{-1}
19	0	−1	0	1	32.111	35.847	−3.74
20	0	1	0	1	57.636	57.219	4.17×10^{-1}
21	0	0	−1	−1	3.778	3.348	4.30×10^{-1}
22	0	0	1	−1	26.399	27.212	-8.13×10^{-1}
23	0	0	−1	1	20.462	18.132	2.33
24	0	0	1	1	56.511	58.252	−1.74
25	0	0	0	0	34.447	34.447	-3.45×10^{-8}

Factorial designs are typically used for screening or response surface optimization. These are a set of factor-value combinations for which responses are measured (a forward simulation run) at either a “low” and “high” parameter value, or a “low”, “centre”, and “high”. Levels of the latter are

denoted -1 , 0 , and $+1$, respectively. As the number of parameters increases, full factorial designs become quite large due to exponential growth in the number of forward model runs required. In this study, we used a Box-Behnken design, which is a modified three-level factorial design. We used the same four reservoir parameters investigated in the previous sensitivity analysis. A Box-Behnken design requires fewer experiments – 25 simulation runs for four parameters – compared with a full factorial design (81 experiments for three levels).

The response surface is an empirical proxy (surrogate) model fitted to the outcomes of the design experiments and is assumed to adequately predict the unobserved response at other parameter combinations. For a three-level design, this model is usually a quadratic polynomial on the parameters of interest with coefficients obtained by linear regression. The model allows estimation of interaction and quadratic effects and is particularly appropriate for Box-Behnken designs [31].

The factor ranges considered for ED are given in Table 3 and reflect a reasonable parameter range for possible EGS projects. For parameters outside this range, the surrogate model is likely to perform poorly. In order to minimise the order of magnitude variability in SRV permeability and obtain a nearly linear response [43], logarithmic scaling was applied to this parameter. Table 4 reports the factor combinations as well as the stable heat output obtained from the FEHM binary search for the 25 design simulations. These range from 1.8 MW for a low-temperature, low fracture count project (ID 9) up to 95 MW for a high temperature, high permeability reservoir (ID 8).

For our surrogate model, we used a general quadratic polynomial that was a function of the four independent reservoir parameters and comprised four linear terms, four interaction terms, four quadratic terms, one constant and two third-order interaction terms, the latter selected to achieve a higher precision of the fitted model. A logarithmic transformation was applied to the model responses before fitting to avoid developing a surrogate model with negative outputs. Model coefficients were obtained from least squares regression. Finally, the surrogate model for the maximum stable thermal output over the 20 year production lifetime is:

$$\begin{aligned} \log_{10} MW_t = & a + bT_i + cD + d\log_{10}K_{srv} + eF + fT_iD + gT_i\log_{10}K_{srv} + hT_iF + iD\log_{10}K_{srv} \\ & + jDF + k\log_{10}K_{srv}F + lT_i^2 + mD^2 + n\log_{10}K_{srv}^2 + oF^2 + pT_i^2D + q\log_{10}K_{srv}^2F \end{aligned} \quad (11)$$

468 where the coefficients a through q are given in Table 5.

Table 5
Regression summary analysis of the surrogate model Eq.11. RMSE = root mean square error.

Terms			Estimate	Std. Error	t value	P> t
Constant	Intercept	a	46.6639	12.143	3.843	0.005
Linear Terms	T_i	b	0.001	0.004	0.234	0.821
	D	c	0.0003	0	1.505	0.171
	$\log_{10} K_{srv}$	d	5.7945	1.607	3.606	0.007
	F	e	-4.5146	0.842	-5.361	0.001
Interaction Terms	$T_i * D$	f	-1.18E-06	6.11E-07	-1.937	0.089
	$T_i * \log_{10} K_{srv}$	g	-0.0009	0	-3.653	0.006
	$T_i * F$	h	-9.44E-05	3.06E-05	-3.09	0.015
	$D * \log_{10} K_{srv}$	i	-1.23E-06	1.22E-05	-0.101	0.922
	$D * F$	j	-8.66E-07	1.53E-06	-0.567	0.586
	$K_{srv} * F$	k	-0.6104	0.112	-5.435	0.001
Quadratic Terms	T_i^2	l	-2.30E-05	5.35E-06	-4.306	0.003
	D^2	m	-2.11E-08	7.27E-09	-2.894	0.02
	$\log_{10} K_{srv}^2$	n	0.1702	0.054	3.181	0.013
	F^2	o	-0.0035	0	-7.645	0
Third order terms	$T_i^2 * D$	p	2.84E-09	1.50E-09	1.895	0.095
	$\log_{10} K_{srv}^2 * F$	q	-0.0199	0.004	-5.325	0.001
R -squared Statistic			0.997			
Adjusted R -squared Statistic			0.990			
RMSE (MW)			1.58			
Observations			25			

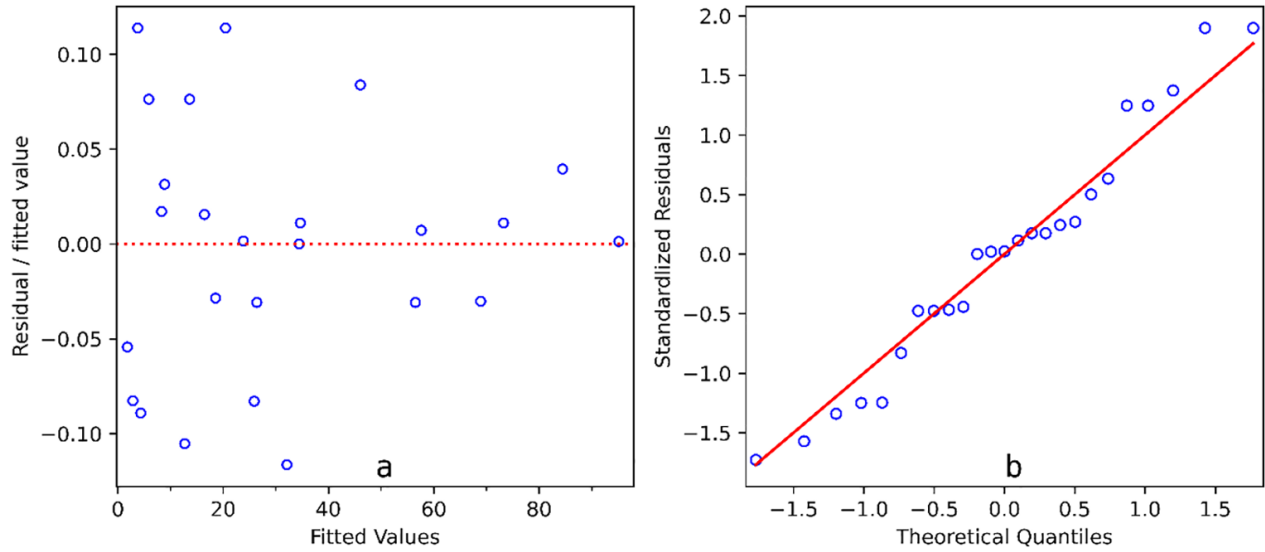


Fig. 9. (a) Relative residuals (residual/fitted value) vs. fitted values plot and (b) Normal Q-Q plot of the regression model.

(2) Validity of the surrogate model

The results of the regression analysis are summarized in Table 5. The R-square statistic and adjusted R-square statistic are 0.997, and 0.990, respectively, indicating a good level of fit by the quadratic polynomial model in the experimental range. The root mean square error (1.58 MW) is and Fig. 9 (residual and normal Q-Q plot) suggests that residuals are unbiased, normally distributed and hence overfitting has been minimised.

We note that although the linear temperature and depth terms, and the interaction terms involving depth are not significant ($P > 0.05$), the quadratic temperature and depth terms are quite significant (Table 5). Therefore, all four reservoir parameters are significant for predicting maximum constant thermal output for the proposed EGS design.

Another 12 simulation test cases (Table 6) were modelled and compared with the predictions of the surrogate model to further evaluate the regression model's performance (Fig. 10). The deviations between test and predicted values are generally small providing a degree of confidence as we proceed to demonstrate how the surrogate model is used. An expanded analysis of response surface interactions between each parameter pair is included in Supplementary Material.

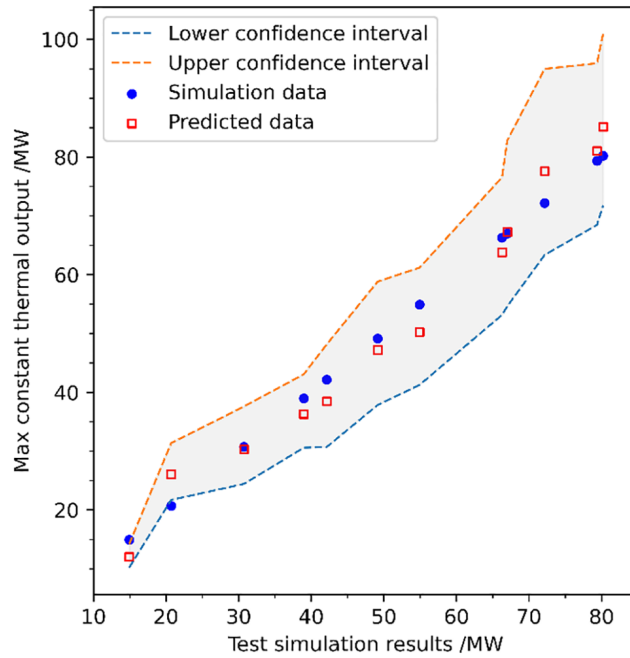


Fig. 10. Comparison between the test simulation results and predicted results by the proxy model.

3.4. Qiabuqia case study

In this section, we apply our surrogate model to an assessment of a hypothetical HDR reservoir within the Qiabuqia geothermal field located in the Gonghe basin, China. The Gonghe Basin, with an area of 21186 km², is located in the Northeast margin of the Qinghai-Tibetan Plateau and is a target geothermal exploitation demonstration area for China [24,25,46,51]. Three geothermal fields have been identified in the Gonghe Basin, including the Qiabuqia, Dalianhai, and Duotanwaerma sites. The Qiabuqia HDR geothermal field, with an area of 246.9 km², is located in the eastern part of the basin and has an average geothermal gradient in a granite stratum of 7.1 °C/100 m, reaching a temperature of 236 °C at 3705 m depth in its GR1 well [24,25,51]. Drill core data revealed that the Qiabuqia reservoir is a naturally fractured granite formation, with permeability in the range of 0.26–0.7mD [25].

Several studies have considered the potential of Qiabuqia geothermal field for EGS power generation project. Zhang et al. [51] built a 3D thermo-hydraulic coupled numerical model of the field to assess heat production under different injection flow rate, temperature and lateral well spacing for a doublet well system. Lei et al. [24] investigated the feasibility of hydraulic fracturing based on laboratory tests, which suggested that hydraulic fracturing under non-proppant or low-proppant condition in Qiabuqia granite formation is feasible. Then, Lei et al. [25] used models to show that a slickwater fracturing treatment could achieve the desired fracture network and half-length target range.

Table 6
Simulation results for testing the surrogate model.

ID	Reservoir initial temperature (°C)	Reservoir depth (m)	SRV permeability (md)	Fracture numbers	Max. constant thermal power output (MW) - simulation	Max. constant thermal power output (MW) - predicted	Residuals (MW)
1	100	3000	3	10	14.917	12.018	2.899
2	225	3000	3	10	49.151	47.179	1.972
3	250	3000	5	10	66.280	63.789	2.492
4	250	3000	0.5	10	30.735	30.306	0.429
5	250	2500	3	10	54.916	50.238	4.678
6	250	3000	3	14	72.159	77.574	-5.416
7	250	3000	3	12	67.007	67.264	-0.257
8	250	3000	1	10	42.130	38.453	3.676
9	250	3000	3	18	79.367	85.147	-5.780
10	250	3000	3	20	80.210	81.039	-0.828
11	168.5	3540	8.5	8	38.973	36.293	2.680
12	128.5	2840	1.5	16	20.695	26.081	-5.386

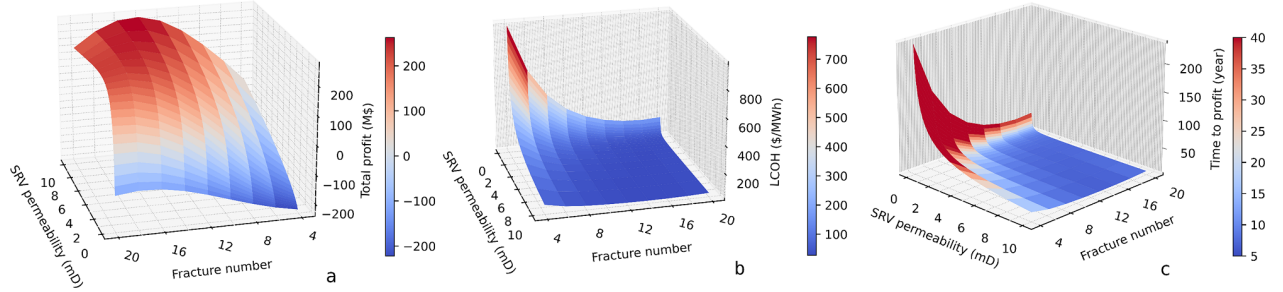


Fig. 11. The relationship of total profit (a), LCOH (b) and time to profit (c) with fracture numbers and SRV permeability.

Shan et al. [37] analyzed the maximum magnitude (~ 3) of induced earthquakes by hydraulic fracturing in Qiabuqia geothermal field combined with focal mechanism, in-situ stress state and tectonic situation. Lei et al. [24,25] also investigated the economics of power generation at the field for a conceptual three-well (vertical and horizontal) EGS system (one injection well flanked by two production well) for different operational parameters.

However, the economic and environmental potential of Qiabuqia geothermal field for direct heating applications, particularly with a partially-bridging fracture design, has not been investigated. Therefore, we have used the surrogate model developed in this study to evaluate the prospects of such a development. Consistent with the underlying FEHM model, we assume a development volume of $2000 \times 500 \times 300$ m at the Qiabuqia geothermal site, which is then accessed by a specified number

of partially-bridging fracture pairs. We then investigate the potential economic performance and environmental benefits given uncertainty about the reservoir properties.

Following Lei et al. [25], we used an initial reservoir temperature of 218 °C at a depth of 3600 m. We then used the surrogate model in its two modes: (1) for optimization, in order to select a preferred fracture number for the development; and (2) for uncertainty quantification, to estimate the range of potential thermal outputs of the project given an unknown range of SRV permeabilities. Commercial and environmental outcomes were also estimated.

For the Qiabuqia geothermal reservoir, viability of an EGS prospect depends critically on the SRV permeability as presented in Fig. 11. The highest profit was achieved at the largest SRV permeability of 10 mD and using 14 hydraulic fractures in the EGS design. The minimum time to profit was obtained using a 14 fracture design. However, the same designs for an SRV permeability 10 times smaller are predicted to yield losses of 159.11 M\$ over the project lifetime and an increase of 19.49 \$/MWh for the levelized cost of heat.

The optimal EGS design at Qiabuqia could support approximately 2.80 km² of indoor heating or 28 000 dwellings at 100 m² each. Moreover, nearly 6×10^8 kg of coal would be displaced by the project, corresponding to 1.6 Mt of CO₂, 5.0×10^6 kg of SO₂, and 4.4×10^6 kg of NO_x. The corresponding CO₂ emission intensity offset is 330 gCO₂/KWh. The lifecycle CO₂ emission from electricity supplied by the same amount of coal emits more than 1000 gCO₂/KWh [7]. This further indicates that EGS heating application could significantly reduce the greenhouse gas emissions.

As the surrogate model cannot predict the thermal power output with 100% confidence (Fig. 10), and because the SRV permeability is unknown, we conducted an uncertainty analysis on project profitability. Based on the prior optimization, we set the design fracture number to 14. We then used Monte Carlo sampling to capture uncertainty in the SRV permeability, sampling from a normal distribution with mean of 1 mD and standard derivation of 0.3. These values represent stimulation enhanced permeability by up to an order of magnitude compared to drill core investigations. For each sampled value of SRV permeability, the sustainable thermal power output is calculated from the surrogate model, taking account of uncertainty in the surrogate fit (see confidence interval in Fig. 10). Finally, the project return is computed based on the simulated thermal power output. In total, 20 000 Monte Carlo simulations were run, with the results shown in Fig. 12. The median estimates of thermal power output, levelized cost of heat and total return are 52.4 MW, 46.72 \$/MWh and

109.97 M\$, respectively, with 95% bounding confidence intervals of [33.6, 73.2] MW, [33.0,84.6] \$/MWh ,and [24.0, 185] M\$.

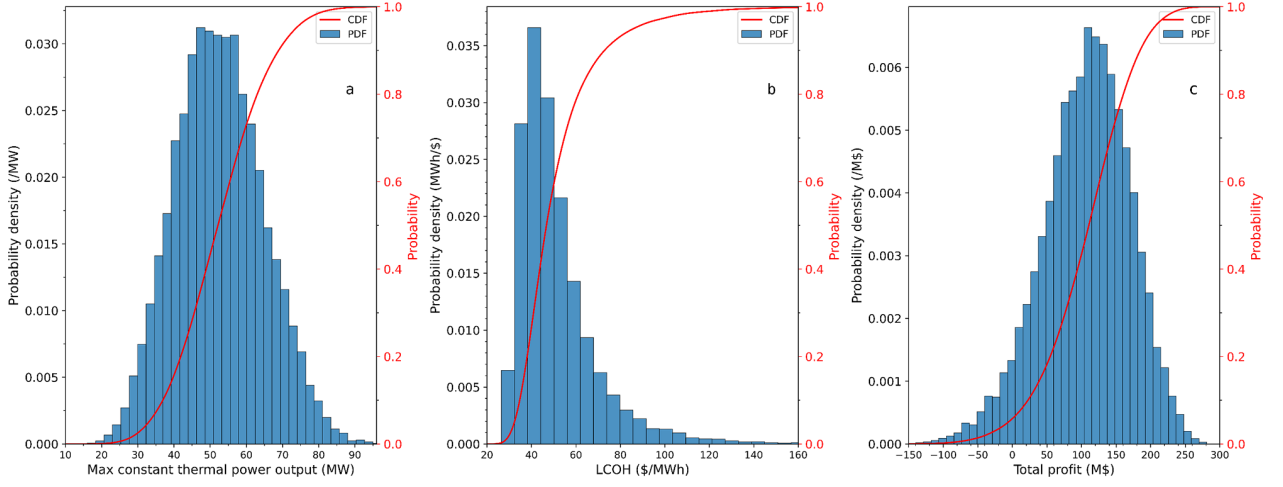


Fig. 12. Monte Carlo analysis of max constant thermal power output (a) LCOH (b), and total return (c) during 20 years under SRV permeability.

4. Discussion & conclusion

This study has built on a previously proposed EGS fracture design [48] that takes advantage of advanced fracture engineering between paired horizontal wellbores in hot dry rock. A binary search simulation framework was developed to optimize thermal power output of this design over a 20 year project lifetime for given input parameters. Using this model, the effect of four key reservoir parameters was evaluated: initial reservoir temperature, reservoir depth, stimulated reservoir volume (SRV) permeability and fracture number. The scale of both economic and environmental benefits was estimated. A surrogate model was then developed using a Box-Behnken experimental design and a quadratic response surface model. Finally, we demonstrated use of the proxy model to optimize fracture design and predict under uncertainty the performance of an EGS residential heating project in Qiabuqia, China. The key findings of this study are summarised below:

1. For the modelled EGS development, SRV permeability plays an essential role in determining profitability, with prospects at the low end (0.1 mD) generally not returning a profit over 20 years. Deeper reservoir formations and larger fracture numbers increase profitability although both exhibit diminishing returns due to increased drilling and stimulation costs.

2. Particular attention is required when optimizing the number of fracture pairs in a partially bridging design as the marginal return of thermal output can become negative at high fracture density.

3. A case study application in the Qiabuqia EGS field suggests the best performance is achieved when using 14 hydraulic fractures. A project of this size could support approximately 2.8 km² of indoor heating for 20 years with considerable emissions reductions ($>\sim 1.5$ Mt of CO₂). A Monte Carlo uncertainty analysis for this case study suggests the most likely thermal power output is 52.4 MW in a 95% interval of [33.6, 73.2] MW with total profit of 109.97 M\$ in the interval [24.0, 185] M\$. The most likely levelized cost of heat for Qiabuqia EGS field is 46.72 \$/MWh in the interval of [33.0, 84.6] \$/MWh.

Although the economic and environmental evaluation of the partially-bridging EGS design is encouraging, much work remains to be done. The numerical model presented here only considers an idealized fracture design, whereas a real reservoir could have interactions between propagating hydraulic fractures and natural fractures, or other complex stress conditions. In future, the effects of secondary stimulation in the SRV that could lead to permeability changes over the operational lifetime could be incorporated, however, such effects would be challenging to quantify without field data. Well spacing is also an important parameter which could be analysed in the further studies. Although we have only considered seasonal heating applications, there are many other uses for EGS heat that could have improved economic feasibility. Finally, for the case study of the Qiabuqia geothermal field presented in this paper, additional reservoir data could reduce uncertainty on the input side, while additional improvements to the ED-RSM design could reduce model uncertainty.

CRediT authorship contribution statement

Pengliang Yu: Conceptualization, Investigation, Methodology, Software, Formal analysis, Writing – original draft, Writing – review & editing, Visualization. **David Dempsey:** Methodology, Software, Resources, Writing – review & editing, Supervision. **Rosalind Archer:** Resources, Writing – review & editing, Supervision.

Declaration of Competing Interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

Acknowledgements

Pengliang Yu is supported by the New Zealand-China Doctoral Research Scholarship co-issued by the Ministry of Foreign Affairs and Trade (New Zealand) and China Scholarship Council (CSC). The authors wish to acknowledge A. Ciriaco at the University of Auckland for helpful discussions about the Experimental Design. We also acknowledge the Centre for eResearch at the University of Auckland who provided computational support for this research.

Appendix A. Supplementary data

Supplementary data to this article can be found online at <https://doi.org/10.1016/j.enconman.2022.115405>.

References

- [1] Asai P, Panja P, McLennan J, Moore J. Performance evaluation of enhanced geothermal system (EGS): surrogate models, sensitivity study and ranking key parameters. *Renewable Energy* 2018;122:184–95.
- [2] Augustine Ca. A methodology for calculating EGS electricity generation potential based on the gringarten model for heat extraction from fractured rock. *GRC Trans* 2016;40.
- [3] Beckers KF, Kolker A, Pauling H, McTigue JD, Kesseli D. Evaluating the feasibility of geothermal deep direct-use in the United States. *Energy Convers Manage* 2021;243(September):114335. <https://doi.org/10.1016/J.ENCONMAN.2021.114335>.
- [4] Beckers KF, Lukawski MZ, Anderson BJ, Moore MC, Tester JW. Levelized costs of electricity and direct-use heat from enhanced geothermal systems. *J Renewable Sustainable Energy* 2014;6(1):013141. <https://doi.org/10.1063/1.4865575>.

- [5] Beckers KF, McCabe K. GEOPHIRES v2.0: updated geothermal techno-economic simulation tool. *Geothermal Energy* 2019;7(1):1–28. <https://doi.org/10.1186/s40517-019-0119-6>.
- [6] Beckers KJ, Ferdinand H. Low-temperature geothermal energy: systems modeling, reservoir simulation, and economic analysis. Cornell University; 2016.
- [7] Bruckner T, Bashmakov IA, Mulugetta Y, Chum H, De la Vega Navarro A, Edmonds J, ... Zhang X. *Energy systems*. 2014.
- [8] Calvez JH, Le ME, Craven RC, Klem JD, Baihly LA, Bennett, and Keith Brook. Real-time microseismic monitoring of hydraulic fracture treatment: a tool to improve completion and reservoir management. *All Days* 2007. <https://doi.org/10.2118/106159-MS>.
- [9] Chan HL, Lee SK. Forecasting the demand for energy in China. *Energy J* 1996;17(1):19–30. <https://doi.org/10.5547/issn0195-6574-ej-vol17-no1-2>.
- [10] Ciriaco AE, Zarrouk SJ, Zakeri G, Mannington WI. Refined experimental design and response surface methodology workflow using proxy numerical models for probabilistic geothermal resource assessment. *Geothermics* 2020;88(November):101911. <https://doi.org/10.1016/j.geothermics.2020.101911>.
- [11] Dempsey D, Kelkar S, Davatzes N, Hickman S, Moos D. Numerical modeling of injection, stress and permeability enhancement during shear stimulation at the desert peak enhanced geothermal system. *Int J Rock Mech Min Sci* 2015;78(September):190–206. <https://doi.org/10.1016/j.ijrmms.2015.06.003>.
- [12] Genter A, Goerke X, Graff J-J, Cuenot N, Krall G, Schindler M, et al. Current status of the EGS Soultz geothermal project (France). *World Geothermal Congress* 2010;2010:6.
- [13] Gringarten AC, Witherspoon PA, Ohnishi Y. Theory of heat extraction from fractured hot dry rock. *J Geophys Res* 1975;80(8):1120–4. <https://doi.org/10.1029/JB080i008p01120>.
- [14] Hallgrímsdóttir Elin, De Wit Joerie Frederik, Fridriksson Thrainn, Ingimundarson Ari, Axelsson Gudni, Steingrímsson Benedikt, Ingason Ingi, Arnason Olafur. n.d. “Preparing Feasibility Studies for the Financing of Geothermal Projects : An Overview of Best Practices.” Accessed

August 21, 2021. <https://documents.worldbank.org/en/publication/documents-reports/documentdetail/733791626931398765/preparing-feasibility-studies-for-the-financing-of-geothermal-projects-an-overview-of-best-practices>.

[15] Häring MO, Schanz U, Ladner F, Dyer BC. Characterisation of the basel 1 enhanced geothermal system. *Geothermics* 2008;37(5):469–95. <https://doi.org/10.1016/j.geothermics.2008.06.002>.

[16] Heidinger P, Dornstädter J, Fabritius A. HDR economic modelling: HDRec software. *Geothermics* 2006;35(5–6):683–710. <https://doi.org/10.1016/j.geothermics.2006.10.005>.

[17] Hogarth R, Holl HG. Lessons Learned from the habanero EGS project. *Transactions - Geothermal Resources Council* 2017;41:865–77.

[18] Huang Y, Zhang Y, Hu Z, Lei H, Wang C, Ma J. Economic analysis of heating for an enhanced geothermal system based on a simplified model in Yitong Basin, China. *Energy Sci Eng* 2019;7(6):2658–74. <https://doi.org/10.1002/ese3.v7.610.1002/ese3.451>.

[19] Jaeger; John Conrad; Neville GW Cook; Robert Zimmerman. n.d. *Fundamentals of Rock Mechanics*. Fourth edi. Accessed April 25, 2020. <https://web-a-ebSCOhost-com.ezproxy.auckland.ac.nz/ehost/ebookviewer/ebook?sid=055eb3f8-3d84-4e48-a48b-98d15813ceb8%40sdc-v-sessmgr03&vid=0&format=EB>.

[20] Jung, Reinhard. 2013. “EGS — Goodbye or Back to the Future.” <https://doi.org/10.5772/56458>.

[21] Kelkar S, Lewis K, Karra S, Zyvoloski G, Rapaka S, Viswanathan H, et al. A simulator for modeling coupled thermo-hydro-mechanical processes in subsurface geological media. *Int J Rock Mech Min Sci* 2014;70:569–80. <https://doi.org/10.1016/j.ijrmms.2014.06.011>.

[22] King George E. 2010. “SPE 133456 Thirty Years of Gas Shale Fracturing: What Have We Learned?” <https://www.onepetro.org/download/conference-paper/SPE-133456-MS?id=conference-paper%2FSPE-133456-MS>.

[23] Kumar D, Ghassemi A, St B. Multistage Hydraulic Fracturing of EGS Wells with Application to FORGE. In *44 Th Workshop on Geothermal Reservoir Engineering*. 2019.

- [24] Lei Z, Zhang Y, Yu Z, Hu Z, Li L, Zhang S, et al. Exploratory research into the enhanced geothermal system power generation project: the Qiabuqia Geothermal field, Northwest China. *Renewable Energy* 2019;139:52–70. <https://doi.org/10.1016/j.renene.2019.01.088>.
- [25] Lei Z, Zhang Y, Zhang S, Fu L, Hu Z, Yu Z, et al. Electricity generation from a three-horizontal-well enhanced geothermal system in the Qiabuqia Geothermal Field, China: slick-water fracturing treatments for different reservoir scenarios. *Renewable Energy* 2020;145:65–83. <https://doi.org/10.1016/j.renene.2019.06.024>.
- [26] Li T, Shiozawa S, McClure MW. Thermal breakthrough calculations to optimize design of a multiple-stage enhanced geothermal system. *Geothermics* 2016;64(November):455–65. <https://doi.org/10.1016/J.GEOTHERMICS.2016.06.015>.
- [27] Lingen, Paul Van, Jean Marc Daniel, Luca Cosentino, Mustafa Sengul. Single Medium Simulation of Reservoirs with Conductive Faults and Fractures.” In *Proceedings of the Middle East Oil Show*, 541–47. OnePetro. . 2001.
- [28] Lukawski MZ, Anderson BJ, Augustine C, Capuano LE, Beckers KF, Livesay B, et al. Cost analysis of oil, gas, and geothermal well drilling. *J Petrol Sci Eng* 2014;118:1–14. <https://doi.org/10.1016/j.petrol.2014.03.012>.
- [29] Mayerhofer MJ, Lolon EP, Cm Rightmire, Walser D, Cipolla CL, Warplnskl NR. What is stimulated reservoir volume? *SPE Prod Oper* 2010;25(1):89–98. <https://doi.org/10.2118/119890-PA>.
- [30] McCabe, Kevin, Koenraad J Beckers, Katherine R Young, Nathan J Blair. 2019. “GeoVision Analysis Supporting Task Force Report: Thermal Applications. Quantifying Technical, Economic, and Market Potential of Geothermal District Heating Systems in the United States.” National Renewable Energy Lab.(NREL), Golden, CO (United States).
- [31] Mishra, Srikanta, Priya Ganesh, Jared Schuetter, Jincong He, Zhaoyang Jin, and Louis Durlowsky. 2015. “SIMPLIFIED PREDICTIVE MODELS FOR CO2 SEQUESTRATION PERFORMANCE ASSESSMENT.” Pittsburgh, PA, and Morgantown, WV (United States). <https://doi.org/10.2172/1238355>.

- [32] Montgomery Douglas C. 2017. Design and Analysis of Experiments. <https://lccn.loc.gov/2017002355>.
- [33] Norbeck JH, McClure MW, Horne RN. Field observations at the fenton hill enhanced geothermal system test site support mixed-mechanism stimulation. *Geothermics* 2018;74(July):135–49. <https://doi.org/10.1016/J.GEOTHERMICS.2018.03.003>.
- [34] Olasolo P, Juárez MC, Olasolo J, Morales MP, Valdani D. Economic analysis of enhanced geothermal systems (EGS). A review of software packages for estimating and simulating costs. *Appl Therm Eng.* 2016;104:647–58. <https://doi.org/10.1016/j.applthermaleng.2016.05.073>.
- [35] Samin MY, Faramarzi A, Jefferson I, Harireche O. A hybrid optimisation approach to improve long-term performance of enhanced geothermal system (EGS) reservoirs. *Renewable Energy* 2019;134(April):379–89. <https://doi.org/10.1016/j.renene.2018.11.045>.
- [36] Sanyal Subir K, James W Morrow, Steven J Butler, Ann Robertson-Tait. 2007. “Cost of Electricity from Enhanced Geothermal Systems.” In *Thirty-Second Workshop on Geothermal Reservoir Engineering*, 11. <https://pangea.stanford.edu/ERE/pdf/IGAstandard/SGW/2007/sanya11.pdf>.
- [37] Shan, Kun, Yanjun Zhang, Yanhao Zheng, Liangzhen Li, Hao Deng. “Risk Assessment of Fracturing Induced. 2020.
- [38] Shiozawa, Sogo, Mark McClure. 2014. “EGS Designs with Horizontal Wells, Multiple Stages, and Proppant.” *PROCEEDINGS, Thirty-Ninth Workshop on Geothermal Reservoir Engineering*. Accessed January 14, 2019. <https://pangea.stanford.edu/ERE/pdf/IGAstandard/SGW/2014/Shiozawa.pdf>.
- [39] Song X, Shi Y, Li G, Yang R, Wang G, Zheng R, et al. Numerical simulation of heat extraction performance in enhanced geothermal system with multilateral wells. *Appl Energy* 2018;218:325–37. <https://doi.org/10.1016/j.apenergy.2018.02.172>.
- [40] Sun Zhi-Xue, Xu Zhang, Yi Xu, Jun Yao, Hao-Xuan Wang, Shuhuan Lv, Zhi-Lei Sun, Yong Huang, Ming-Yu Cai, Xiaoxue Huang. 2017. “Numerical simulation of the heat extraction in

EGS with thermal-hydraulic-mechanical coupling method based on discrete fractures model.”
<https://doi.org/10.1016/j.energy.2016.10.046>.

[41] Tester J. 2006. The Future of Geothermal Energy in the 21 Century Impact of Enhanced Geothermal Systems (EGS) on the United States St. http://www1.eere.energy.gov/geothermal/egs_technology.html.

[42] Wang G, Song X, Shi Y, Zheng R, Li J, Li Z. Production performance of a novel open loop geothermal system in a horizontal well. *Energy Convers Manage* 2020;206:112478. <https://doi.org/10.1016/j.enconman.2020.112478>.

[43] White CD, Willis BJ, Narayanan K, Dutton SP. Identifying and estimating significant geologic parameters with experimental design. *SPE J* 2001;6(3):311–24. <https://doi.org/10.2118/74140-PA>.

[44] Willis BJ, White CD. Quantitative outcrop data for flow simulation. *J Sediment Res* 2000;70(4):788–802. <https://doi.org/10.1306/2DC40938-0E47-11D7-8643000102C1865D>.

[45] Wu F, Yan Y, Yin C. Real-time microseismic monitoring technology for hydraulic fracturing in shale gas reservoirs: a case study from the southern Sichuan basin. *Nat Gas Ind B* 2017;4(1):68–71. <https://doi.org/10.1016/J.NGIB.2017.07.010>.

[46] Xu T, Yuan Y, Jia X, Lei Y, Li S, Feng B, et al. Prospects of power generation from an enhanced geothermal system by water circulation through two horizontal wells: a case study in the Gonghe Basin, Qinghai Province, China. *Energy* 2018;148:196–207. <https://doi.org/10.1016/j.energy.2018.01.135>.

[47] Yoon KS, Jeon JS, Hong HK, Kim HG, Hakan A, Park JH, Yoon WS. Deep Drilling Experience for Pohang Enhanced Geothermal Project in Korea. In *Proceedings of the World Geothermal Congress, Melbourne, Australia. Vol. 19. 2015*.

[48] Yu P, Dempsey D, Archer R. A three-dimensional coupled thermo-hydro-mechanical numerical model with partially bridging multi-stage contact fractures in horizontal-well enhanced geothermal system. *Int J Rock Mech Min Sci* 2021;143(July):104787. <https://doi.org/10.1016/J.IJRMMS.2021.104787>.

- [49] Zabalza-Mezghani I, Mezghani M, Blanc G. Constraining reservoir facies models to dynamic data - impact of spatial distribution uncertainty on production forecasts. Society of Petroleum Engineers (SPE) 2001. <https://doi.org/10.2118/71335-ms>.
- [50] Zakhour, Nancy, Mark Sunwall, Raul Benavidez, Leah Hogarth, and Jian Xu. 2015. "Real-Time Use of Microseismic Monitoring for Horizontal Completion Optimization Across a Major Fault in the Eagle Ford Formation." Society of Petroleum Engineers - SPE Hydraulic Fracturing Technology Conference 2015, February, 380–93. <https://doi.org/10.2118/173353-MS>.
- [51] Zhang C, Jiang G, Jia X, Li S, Zhang S, Hu D, et al. Parametric study of the production performance of an enhanced geothermal system: a case study at the Qiabuqia Geothermal Area, Northeast Tibetan Plateau. Renewable Energy 2019;132:959–78. <https://doi.org/10.1016/j.renene.2018.08.061>.
- [52] Zimmerman RW, Bodvarsson GS. Hydraulic conductivity of rock fractures. Transp Porous Media 1996;23(1):1–30. <https://doi.org/10.1007/BF00145263>.
- [53] ZYvoLosKI GA, RoBINSON BA, DASH Z, TREAsE LL. Models and Methods Summary for TheFEHM Application. 1995. https://fehm.lanl.gov/pdfs/fehm_mms.pdf.
- [54] Zyvoloski GA, Robinson BA, Dash ZV, Trease LL. User's Manual for the FEHM Application – A Finite-Element Heat- and Mass-Transfer Code. 1997. Los Alamos, NM. <https://doi.org/10.2172/14902>.
- [55] Wang Heating Engineering. 1993. Heating Engineering. China Construction Industry Press (Engl. Ed.).
- [56] CJJ34-2010 Standard database. "Code for design of urban heating pipe network [with clause description]" 2010 <http://www.jianbiaoku.com/webarbs/book/285/315608.shtml>. (Engl. Ed.).
- [57] Hancheng Y, Yuan S, Xianghua Y. Discussion on solar heating technology in Xining area. J Qinghai Univ: Nat Sci Ed 2008;26(5):89–93.