Hydraulic Fracturing Experiment Investigation for the Application of Geothermal Energy Extraction

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ABSTRACT: As an attractive renewable energy source, deep geothermal energy is increasingly explored. Granite is a typical geothermal reservoir rock type with low permeability, and hydraulic fracturing is a promising reservoir stimulation method which could obviously enhance the reservoir permeability. Previous hydraulic fracturing studies were mostly conducted on artificial samples and small cylindrical granites. The fracturing pressures of artificial samples and small real rock sample were much lower than that of field operation, and it was difficult to observe morphological changes in small rocks. Hence, this paper presents a hydraulic fracturing experimental study on large-scale granite with a sample size of 300 × 300 × 300 mm under high temperatures. Besides, injection flow rate is an important parameter for on-site hydraulic fracturing; previous studies usually only focused on breakdown pressure, and there is a lack of comprehensive analysis about fracturing pressure curves and fracturing characteristics caused by different injection flow rates. This study aims to investigate the influence of injection flow rate on different pressure curve characteristic parameters which are initiation pressure, propagation time, breakdown pressure, postfracturing pressure, fracture geometry, and fracture permeability. The mean injection power was proposed to roughly estimate the fracture total lengths. These results could provide some guidance for field-scale reservoir stimulation and heat extraction efficiency improvement.

1. INTRODUCTION

As a kind of renewable energy, geothermal energy can meet the energy demands with less pollution to the environment. An enhanced geothermal system (EGS) is originally called a “hot dry rock” (HDR) system; different from hydrothermal geothermal resources. HDR is another buried geothermal resource that can be used for electricity generation. To extract heat in deep underground, hydraulic fracturing is commonly used to improve heat production efficiency and enhance reservoir permeability. On-site hydraulic fracturing involves drilling a hole at least 3 km deep into a rock layer where temperature is higher than 100 °C. Fluid is pumped under high pressure into rocks to enhance the reservoir connectivity. The hydraulic fracturing fluid for geothermal energy mining is usually cold water, and no chemical additives are required, whereas in hydraulic fracturing for oil and gas production, around 10−30 chemicals are added into the fracturing fluid per well, and even if the proportion of chemicals in the fracturing fluid is tiny, the effect of chemicals is not negligible when tons of fluid are pressed into the rock formation. In addition, the acidizing method is always used in the hydraulic fracturing of shale gas mining.

When performing a hydraulic fracturing operation in a HDR reservoir, the injection flow rate is the first critical element to consider. The injection flow rate and injection pressure are the most important operational parameters that are used in the hydraulic fracturing scheme. Drilling and fluid high-pressure injection in field are always a costly work and sometimes making it difficult to conduct on-site hydraulic fracturing investigations in an EGS environment. Thus, it is necessary to use laboratory experiments as auxiliary analytical methods.

Several researchers have conducted studies in order to investigate the mechanism of a hydraulic fracture creation in an EGS reservoir. They have shown that the flow rate and fluid pressure play important roles in the process of fracture initiation and near wellbore propagation. Frash et al. developed a true-triaxial apparatus and conducted an experiment at the temperature of 50 °C; they demonstrated that an EGS reservoir could be created within an intact rock reservoir in the laboratory, and an intact granite could be hydraulic fractured in an appropriate injection flow rate. Zoback et
al.\textsuperscript{13,14} performed hydro-compression experiments on six rock samples from the Bakken Play and found that pre-existing microcracks could influence the fracture pathway, and then they examined the influence of pressure during hydraulic fracturing in shale gas reservoirs with faults, and after the long-term observation of the micro-seismic event, they suggested that the reservoir with the pre-existing faults could be cracked in low pressure. Solberg et al.\textsuperscript{15} performed laboratory hydraulic fracturing experiments on oil shale and low-permeability granite of small cylindrical samples through pseudo-triaxial confining stress methods, and results showed that either shear or tension fractures could be induced depending on the level of injection pressure. Fallahzadeh et al.\textsuperscript{16} performed hydraulic fracturing tests in 150 mm synthetic cubic samples to simulate real far field stress conditions and showed that with the increase of the fluid viscosity and flow rate, the fracture initiation angle increased and fracture propagated along more curved planes. Guo et al.\textsuperscript{17} simulated horizontal well hydraulic fracturing experiments on shale outcrops and analyzed the effects of confining stress on the fracture morphology, and results showed that when the stress difference was increased, the induced hydraulic fractures were more interconnected, forming a relatively more complex fracture system.

Additionally, several numerical simulation studies have been carried out in order to model and analyze the mechanism of fracture creation. Al-Busaidi et al.\textsuperscript{18} performed hydraulic fracturing simulations based on a two-dimensional Particle Flow Code Modeling, and they simulated a variety of interactions between hydraulic fractures. The numerical model results showed that the hydraulic induced fracture was predominantly tensile failure, and the shear fractures were much less, and these behaviors were in accordance with the observed experiments. Weng et al.\textsuperscript{19} tried a numerically modeled hydraulic fracture network in shale with variable injection flow rates, and their simulation results showed that the variable injection-rate technology was a potentially good method to form a complex fracturing network. Rothert and Shapiro\textsuperscript{20} proposed a numerical modeling method based on a diffusive process of pore-pressure relaxation in sub critically stressed rocks, and results showed that the numerical model could be used for the spatio-temporal distributions of microfracture events in field, and their findings supported the idea that pore-pressure relaxation was an important mechanism for triggering microearthquakes. Rahman and Rahman\textsuperscript{21} simulated the fluid-rock coupling process of hydraulic fracturing with a finite element method. They found that the orientation of prior induced fracture and its length have a profound effect on the posteriorly induced hydraulic fracture, and this phenomenon has been observed in most field cases. Pakzad et al.\textsuperscript{22} proposed a finite element numerical model and predicted the fracture behaviors and permeabilities, the after fracturing permeability was found to decrease with the heterogeneity level of block, the hydraulically driven fractures propagated perpendicular to the minimum principal far-field stress direction, and the proposed model could be applied to the plane-strain simulation of the fluid pressurization on a large-scale rock.

Although numerous works have been conducted to investigate the influencing factors of granite hydraulic fracturing, the results have not been consistent. Previous studies on EGS hydraulic fracturing have mostly been carried out by artificial cement samples with artificial materials including concrete, cement mortar, and Perspex\textsuperscript{16,23,24} Even though a limited number of studies have used real rocks, most experiments used small cylindrical samples (50 mm in diameter and 100 mm in height) for fracturing testing under a pseudo-3D confining pressure state.\textsuperscript{25} The tensile and shear strengths (SSs) of cement samples are much lower than that of granites. Smaller pressure can trigger the fracture and form a fracture network. Therefore, even large-sized cement samples are easily fractured under laboratory conditions. The fracturing results obtained by replacing granite with cement are probably not consistent with the actual fracturing condition of granite. In small cylindrical or cubic granite samples, because of the small sample size, the required fracturing pressure is also small, and the formation of fracture network is also limited. It is generally difficult to determine the morphological changes of fractures due to the small size of the samples and the fracturing results are not in good agreement with the field-site hydraulic fracturing. As a result, these conclusions are often difficult to be applied in field-scale hydraulic fracturing to guide the actual EGS project.

Hydraulic fracturing involves a complicated fluid-solid coupling process. Because of the compactness and the low permeability of the granite, an intact large-size granite sample requires a high fracturing pressure to trigger a fracture. To have a better understanding of the hydraulic fracturing characteristics, we conducted experiments by using a true tri-axial fracturing apparatus designed by Jilin University. The tested granite samples were collected from the Songliao Basin geothermal field in the northeastern part of China. In order to investigate influence of injection flow rate on hydraulic fracturing at high temperatures, we performed hydraulic fracturing tests at different injection flow rates on six samples at 150°C. The initiation pressure, breakdown pressure, postfracturing pressure, and propagation time were analyzed. The rock samples were cut in half, and the fracture geometries were observed. The fracture permeabilities after hydraulic fracturing were calculated based on pressure data. Research results in this work can provide a better understanding for hydraulic fracturing in granite at a high temperature and give

Figure 1. (a) Complete outcrop rock sample; (b) Outcrop rock sample was cut into 300 × 300 × 300 mm cubes.
some guidance for the design of field-scale hydraulic fracturing operation.

2. LABORATORIAL TESTS

2.1. Background. The Songliao Basin is located in the northeastern part of China. The winter temperature is very low, and the residential heating period is long (a long heating period of 7 months, with a heating temperature of 30–50 °C). However, the population distribution is scattered, it is difficult for all residents to achieve centralized heating. The Songliao Basin is a typical HDR reservoir with high heat flow and abundant reserves. Therefore, heating by the EGS is a feasible method. In addition, according to the geothermal gradient, only taking heat from a depth of more than 2000 m, the water could be heated to a temperature high enough for residential heating.29 At this depth, the strata are already granite. Therefore, it is necessary to use granite for hydraulic fracturing experiments at high temperatures.

Granite samples used in this study are taken from the place nearby YS-2 well in the Songliao Basin. The YS-2 well is a geothermal exploration well, and exploration data show that the geothermal resources here are abundant with a high heat flow. As large size intact granite samples cannot be obtained from a wellbore, we use outcrop as a substitute (Figure 1a). To simulate in-situ stress conditions, the experiments are planned to be carried out on cube-shaped samples, where three independent stresses could be applied. The rock are cut into 300 × 300 × 300 mm cubes (Figure 1b), and the lithology is tested. A total of ten small granite samples were used for rock properties and mineral composition testing. All of these ten samples were rock debris when cutting outcrops into cube-shaped samples. It meant that the properties and mineral testing of these ten samples were the same with the aforementioned six large size cubic samples. All of the tests were conducted in the Groundwater Resources and the Environment Education Ministry Key Laboratory of Jilin University. The rock property tests results are shown in Table 1, and the property range indicated the minimum and maximum in each property test. The average value represented the average property value in each test. Each mineral had a specific X-ray diffraction spectrum. The characteristic peak intensity in the spectrum was related to the content of minerals, and then the mineral qualitative and quantitative composition could be obtained. The rock debris was processed into rock powder, and the X-ray diffraction test analysis was carried out to obtain the mineral composition which is shown in Table 2.

| mineral composition | value |
|---------------------|-------|
| Quartz              | 0.35  |
| potash feldspar     | 0.23  |
| plagioclase         | 0.30  |
| others              | 0.12  |

2.2. Rock Sample Preparation. The following steps are used for rock sample preparation, as shown in Figure 2: (1) the outcrops are cut into 300 × 300 × 300 mm cubes with a surface tolerance of ±1 mm, perpendicularity of ±1°, and higher homogeneity and more intact ones are preferred. (2) A borehole is drilled in the center of the rock surface, with the depth of 150 mm, and the wellbore bottom is in the center of the rock sample. (3) The hole is drilled at 650 rpm with a 14 mm masonry drill bit. The slow rate of penetration ensured maximum cutting efficiency. The hole is drilled as soon as the sample is removed from the water bath to reduce the risk of micro cracks forming around the wellbore. (4) After drilling, distilled water is used to flush the borehole for cleaning all rock debris in the borehole. (5) After the distilled water in the wellbore completely evaporates, and the wellbore wall is dried, and the epoxy grout resin is injected into the wellbore. (6) The water injection tube (Figure 2c) is a hollow stainless steel tube with a 10 mm outside diameter, a 160 mm length, and it could withstand a maximum internal pressure of 55.3 MPa. The tube is slightly roughened to provide a better bond between the tube, adhesive, and block. (7) The injection tube is designed to have two side holes for fluid to flow through to fracture the rock near the wellbore bottom. (8) A transparent plastic is sealed on the side holes to prevent the glue flowing into the injection tube, and then the tube is pressed into the wellbore to be glued; 150 mm of the tube is stuck into the rock sample, and the transparent plastic prevents epoxy grout flowing into the tube. (9) 10 mm of the tube, as a water injection hole, is exposed outside the rock sample, and then water flows into the rock from the exposed part; when the water is injected into the tube, the plastic fails and water is injected into the rock. (10) After the injection tube is glued in the rock, they are placed at room temperature for more than 48 h, so that the tube and the rock are completely bonded; the diagram of a prepared sample is shown in Figure 3.

Because of the compactness and the low permeability of the granite, an intact large-size granite sample requires a high fracturing pressure to trigger the fracture. The main difficulty in the hydraulic fracturing experiment is sealing the injection tube into the rock. The adhesive should have sufficient resistance to high fluid pressure. The adhesive strength needs to be much higher than the fracturing pressure, the adhesive needs to completely wrap the injection tube, there should be no adhesive strength weak point around the injection tube, and the colloidal properties should be stable at high temperatures, then the water will not flow out along the gap between the injection tube and the wellbore wall and can be forced into the rock to induce a fracture.
In order to make the epoxy grout resin adhesive better glued to the tube and withstand higher water pressure. After many experiments, we find a gluing process, which can guarantee sufficient adhesive strength between the wellbore and tube. Some matters for attention are put forward: (1) after the well is drilled, the rock debris may be left in the well; to prevent the adhesive weak point because of the rock debris, the inside wall of the wellbore must be washed with distilled water, and the tube can be glued after the water in the wellbore is completely dry. (2) The diameter of the wellbore is slightly larger than the outside diameter of the injection tube. A narrow annulus (about 2 mm) between the wellbore and tube is considered for the placement of adhesive, and there will be enough space for the adhesive filling the annulus. The tube can be completely wrapped by the adhesive. The narrow annulus also could minimize the effect of the adhesive on tube and wellbore stress distribution, for the time when the cubic sample will be under triaxial stresses. (3) The usual method to glue the tube is to apply the adhesive around the tube, and then the tube is inserted into the wellbore; during the whole process, the adhesive around the tube is easy to touch the inside wall of the wellbore, forming weak bond points. As a result, the adhesive cannot withstand high pressure; the water may flow out along the annulus, and no fracture is induced. Hence, we propose an improved adhesive method; the adhesive material is quite viscous, and it could not easily fill the annulus completely. To resolve this problem, initially, the adhesive is put into a syringe with a long needle. The needle should be longer than the depth of the wellbore. The adhesive is carefully injected from the wellbore bottom, as the adhesive rises, the syringe is gradually lifted until there is enough adhesive in the wellbore. Then the tube is slowly inserted into the wellbore and firmly pushed against the wellbore bottom, and the spilled adhesive is wiped off. The adhesive flowed upward in the annulus and filled the whole annulus space. This upward flow of the adhesive ensures that no air bubble is left in the narrow annulus and consequently guarantees sufficient adhesive strength.

2.3. Hydraulic Fracturing Experimental Equipment.

The tests were conducted on a true-triaxial hydraulic fracturing apparatus (Figure 4) that was developed by Jiangsu Nantong Petroleum Instrument Co. Ltd and the Groundwater Resources and the Environment Education Ministry Key Laboratory of Jilin University. The advantages of this fracturing equipment are that it can provide true triaxial confining stresses and has a heating device to simulate the HDR temperature environment. The test system and its main

Figure 2. Rock sample preparation: (a) drilling the borehole; (b) rock sample after drilling the borehole; (c) water injection tube; and (d) prepared rock sample.

Figure 3. Diagram of the prepared sample: the longitudinal profile.
Figure 4. True-triaxial hydraulic fracturing apparatus: (a) water injection system; (b) steel framework, confining pressure system and the heating system; (c) fracturing capsule; and (d) closed view of the apparatus.

Figure 5. (a) Water outlet hole in the flat jack and (b) water inlet on the rock; the black color ring is the rubber ring, and the white color wrapped the black color is the PTFE sealing tape.

components are shown in Figure 4. The apparatus consists of four subsystems: a water injection system, a steel framework and confining pressure system, a heating system, and a computer monitor system.

The water injection system consists of four syringe pumps, they can provide up to a maximum pressure of 80 MPa, and a maximum injection flow rate of 30 mL/min. The steel framework and confining pressure system consists of a steel framework with a yield stress of 60 MPa, three square flat jacks, and a control panel. The steel framework contains a fracturing capsule that could support a cubic rock sample no larger than \(300 \times 300 \times 300\) mm. The three square flat jacks are placed in the three directions of fracturing capsule and could provide three independent stresses, the independent orthogonal stresses are used to simulate the underground in situ reservoir stresses. Sample faces directly loaded by the flat jacks and the opposing reaction faces supported by the framework are hereby referred to as active and passive faces, respectively. Each flat jack is pressurized via an independent oil syringe pump with active digital pressure monitoring. The face of square flat jack, which comes into contact with the sample face, is 5 mm smaller than the sample on each side. This ensures that the adjacent flat jacks will not come into contact with each other when applying triaxial confining stresses. The heating system can heat the sample to a maximum temperature of 150 °C. The heating system consists of three electrical heated elements. Two are installed on the top of the framework internal surface, and one is installed at the bottom of the fracturing capsule. Two 1200 W heating elements installed on the frame body can give approximately 2400 W heating capacity. An additional 1000 W heating element is installed on the bottom plate. The heating system allows different temperature set-points for the framework and capsule elements. The framework insulation encloses the whole assembly when heated, improves the safety, and reduces thermal losses. The computer monitor system could monitor the hydraulic fracturing pressure and rock sample temperature and control the injection flow rate.

2.4. Experimental Setup. As it is mentioned in the introduction section, the main goal of this study is to investigate the effects of the fracturing fluid flow rate on the fracture initiation, propagation geometry, and micro cracks. Therefore, to ensure that the stress regime will not influence the tests’ results, the same stress regime was considered to be applied on all samples. Consequently, a maximum principal stress \(\sigma_1\) of 12 MPa, an intermediate principal stress \(\sigma_2\) of 8 MPa, and a minimum principal stress \(\sigma_3\) of 4 MPa were
applied on each sample. Such stress components could represent a normal in situ stress regime where $\sigma_1 > \sigma_2 > \sigma_3$.

When hydraulic fracturing, the water fracturing pressure is usually between 10 and 40 MPa. The key to the success of this experiment is to ensure the sealing of the water outlet hole (Figure 5a) on the flat jack and the water inlet of the injection tube. Otherwise, the water will flow out from the connection of the flat jack and the injection tube without fracturing the rock sample. As the water outlet on the flat jack is slightly larger than the water inlet of the injection tube, to prevent fluid leakage, a rubber ring (Figure 5b) is sleeved on the injection tube head, and the PTFE sealing tape (Figure 5b) was wrapped on the outside of the rubber ring.

In ideal circumstances, it is expected that a hydraulic fracture initiates and propagates in a plane known as preferred fracture direction (PFD), which is perpendicular to the minimum principal stress direction. Therefore, all testing samples were placed in the fracturing capsule in such a way that the wellbore axis was along the direction of the intermediate principal stress. Also, the maximum and the minimum principal stress were set perpendicular to the wellbore axis. This method makes it easy to observe relationship among the fractures, the maximum and the minimum principal stress when the sample is cut in half. Figure 6 shows the sample installed in the testing system.

It is noteworthy that the principal stresses were applied in four stages. Initially, the intermediate principal stress was increased to the minimum principal stress magnitude. This procedure would ensure the exposed part of the injection tube is insert into the water outlet hole on the flat jack. Then the other two stresses were increased to the minimum principal stress. At this point, the minimum stress syringe pump was set on a constant pressure. Next, the intermediate and the maximum stress were increased to the intermediate principal stress, and at this stage, the intermediate stress was kept constant. At the final stage, the maximum principal stress was increased to its required value and then its corresponding pump was set on constant pressure mode. This stress path was consistently applied to all samples tested in this study.

2.5. Experimental Process. Laboratory experiments, commonly, are a practical way to investigate the mechanism of hydraulic induced fractures and provide a better visual method to observe the fracture geometries. Samples were placed in a cubic capsule and subjected to predetermined stress conditions. The triaxial confining pressures represented in situ stresses. It was important to install the sample properly for the success of the experiment. Distilled water was used as the fracturing fluid to examine the effects of injection flow rate on the fracturing pressures and propagation geometries. Six granite samples were test under 150 °C, and for each sample, the fluid is injected with a specific flow rate ranging from 5 to 30 mL/min. During testing, fracturing pressures were recorded. Hydraulic diffusivity was a function of fracture permeability, injected fluid viscosity, and poroelastic modulus of rock, we used pressure diffusion equation to fit and modeled the pressure curves, the outcome of modelling was the value of hydraulic diffusivity which could be used to estimate fracture permeability.

Experimental procedures: (1) The apparatus was checked. (2) The rock sample was placed into the fracturing capsule. (3) Oil was pumped into the syringe pump. Triaxial stresses were applied to the rock sample at a rate of 0.2 MPa/s, and the stress curves were displayed in real time on the computer monitor to ensure that the rock sample was not damaged before the water was injected. (4) The heating system was turned on to heat the rock sample. The rock samples were heated to 150 °C, and the target temperature was maintained for 5 h to guarantee that the sample was evenly heated. (5) After the rock temperature was stabilized, through the water injection syringe pumps, water was injected into the rock via the tube, and the injection flow rates were constant. Six injection flow rates were chosen (5, 10, 15, 20, 25 and 30 mL/min). (6) When a large amount of water flowed out of the fracturing capsule, the fracturing pressure was not changed and reached an equilibrium state, and we considered hydraulic fracturing was complete and the water-injecting syringe pump was turned off. (7) The triaxial stresses were released. The
stress release process was the same as the applying process. The maximum principal stress was decreased to the intermediate principal stress, and then the intermediate and the maximum stress were decreased to the minimum principal stress. Last, the three principal stresses were released to zero. (8) The rock sample was taken out from the fracturing capsule, and the fractures were observed and recorded immediately. The condition of water flowing out from the fractures could be clearly seen, and the water flowed out of the rock sample along the fractures. (9) The rock samples were cut in half to observe the fractures. (10) Fractures were marked by a marker pen, and photographs were taken for recording. (11) The experimental data were analyzed.

2.6. Experimental Uncertainty. The uncertainty of the experimental results was mainly induced by the measurement of injection flow rate, hydraulic pressure, and fracture size, including the uncertainty induced by measuring accuracy. The length of fractures was measured using Vernier calipers, whose accuracy was ±0.02 mm. The accuracy of the hydraulic pressure was ±1% of the full range of 80 MPa. The accuracy of the injection flow rates was ±1% of the full range of 30 mL/min.

3. RESULTS

In this experiment, hydraulic fracturing tests were conducted on six 300 × 300 × 300 mm cubic granite samples. The tests involved injection flow rates from 5 to 30 mL/min with a heated temperature of 150 °C (150 °C is the maximum temperature the heating system could provide). A confining stress regime where \( \sigma_1 = 12 \text{ MPa}, \sigma_2 = 8 \text{ MPa}, \text{ and } \sigma_3 = 4 \text{ MPa} \) was maintained on all six samples. The wellbore and perforations were prepared with repeatability to make sure that each sample would be nearly identical. The triaxial confining stresses were applied slowly with a significant level of caution and care to prevent stressing fractures in the loading process. This allowed that the majority of the variables presented in the experiment were controlled, and then the effects of the injection flow rate could be observed and analyzed. Table 3 presents the fracturing test parameters and the break pressures of each test.

At the end of each test, the triaxial confining stresses were released to atmospheric pressure. The sample was then taken out of the fracturing capsule. The fractures on the sample were photographed and marked (Figure 7a). Then samples were carefully cut into two-halfs (Figure 7b). The fractures on each half were photographed to record the fracture geometries. Also, the pressure-time curves were used to interpret the hydraulic fracturing process.

Figure 8a–f shows the curves of fracturing pressure and pressurization rate versus time during the whole fracturing process of experiments 1 to 6, where the hydraulic fracturing injection flow rates were 5, 10, 15, 20, 25, and 30 mL/min. The black curves represent the fracturing pressures. As shown in Figure 8a–f, all the pressure curves have similar shapes; a particular pressure–time curve could be divided into four main phases: (1) initial pressure development phase, (2) well-bore pressurization phase, (3) fracturing phase, and (4) postfailure phase. In the initial pressure development phase, as the water was injected, the water just entered the hole and the injection pressure kept close to zero and remained unchanged. After the water was injected, the water just entered the hole. As the injection pump was in an adjacent room, the water injection pipeline was somewhat long, and this stage lasted about 130–400 s, and ended when the hole was filled with water. During this time, the fracturing fluid was just filling the injection tube and the wellbore. Very small (almost horizontal) pressure development was identified, and the injection pressure kept close to zero and remained unchanged. After the wellbore was completely filled, during the well-bore pressurization phase, continuing to inject water into the hole resulted in the rock near the wellbore bottom to be pressurized and the fracturing pressures started to quickly build up with almost a constant increase rate.

| test no. | injection flow rate (mL/min) | initiation pressure (MPa) | breakdown (maximum) pressure (MPa) | postfracturing pressure (MPa) | propagation time (s) |
|----------|-------------------------------|--------------------------|-----------------------------------|-------------------------------|---------------------|
| 1        | 5                             | 21.06                    | 22.12                             | 11.20                         | 613                 |
| 2        | 10                            | 22.95                    | 24.68                             | 12.69                         | 498                 |
| 3        | 15                            | 25.61                    | 27.65                             | 11.27                         | 447                 |
| 4        | 20                            | 27.91                    | 30.06                             | 9.97                          | 343                 |
| 5        | 25                            | 28.71                    | 34.10                             | 7.68                          | 220                 |
| 6        | 30                            | 32.52                    | 36.01                             | 3.11                          | 88                  |

Figure 7. (a) Photo of the fractured granite sample: the black lines indicate fractures, and red water flows out of the rock from these fractures; (b) fractured rock sample was cut in half.
in the fracturing phase, the fractures were initiated and propagated, new volume was created, the pressure reached the maximum which was also called breakdown pressure, and then there was a large drop. In this phase, the rock had been fractured by the high fracturing pressure, and new fluid was pressurized in to compensate the newly created volume. Because of the existence of newly created fractures, the pump pressure dropped rapidly and did not rise with the continuous fluid injection, and a large pressure drop was observed. The maximum pressure was 22.12, 24.68, 27.65, 30.06, 34.10, and 36.01 MPa when the injection flow rates were 5, 10, 15, 20, 25, and 30 mL/min respectively. It was shown that the breakdown pressure increased with the increase of injection flow rate. The fracturing phase lasted a few seconds, after the fracture tip hit the sample boundary, the test reached to the last phase, postfailure phase, and the fluid flowed out of the sample. Even though water was continuously injected into the rock sample, the pump pressure did not change. This meant that the wellbore pressure was now equal to the fracturing fluid frictional pressure loss along the created fractures; newly injected water would not enter into the rock body for fracturing, and fracture would not be created. The injection

![Figure 8](https://pubs.acs.org/acsomega/2020/5/6674.jpg)

Figure 8. Fracturing pressure–time curves and pressuring rate–time curves: (a–f) hydraulic pressure curves and pressure rate curves when the injection flow rate is 5, 10, 15, 20, 25, and 30 mL/min, respectively.
pressures did not change over time, and the wellbore pressures were stable; water just flowed along the created fractures into the fracturing capsule.

The red curve represents the pressurization rate. It could help to analyze different stages during the fracture propagation. As shown in Figure 8a−f, a typical pressurization rate curve could obviously reflect different phases during fracture propagation. In the initial pressure development phase, as the water only filled the injection tube and the pressure was almost keep at zero, the pressure did not change at this phase and the pressurization rate remained at zero. In the well-bore pressurization phase, fracturing fluid filled full of the well-bore and the pressure was applied to the rock mass around the wellbore bottom. As the injection flow rate was constant, the pressurization rate rose rapidly and then fluctuates near a constant value, this represented the pressure curve increased close to a straight line at this phase. When entering the fracturing phase, the pressurization rate decreased rapidly until it became negative, which indicated that the pressure decreased dramatically in a non-linear form. It showed that the fractures propagated very fast, and the newly pumped fracturing fluid could not rapidly fill the newly formed fractures. In the last phase, the fracture tip hit the sample boundary, no new fracture was created, the fracturing fluid just flowed out of the rock along the formed fractures, the pressure does not change, and the pressurization rate gradually becomes zero.

Figure 8a illustrates the evolution of the hydraulic pressure and pressurization rate for experiment 1 conducted at an injection flow rate of 5 mL/min, phase 1−4 are (1) the initial pressure development phase, (2) well-bore pressurization phase, (3) fracturing phase, and (4) postfailure phase. Figure 8b shows the curves when the injection flow rate is 10 mL/min. Figure 8c illustrates the curves when the injection flow rate is 15 mL/min. Figure 8d illustrates the curves when the injection flow rate is 20 mL/min. Figure 8e illustrates the curves when the injection flow rate is 25 mL/min. Figure 8f illustrates the curves when the injection flow rate is 30 mL/min. As shown in Figure 8a−f, the shape of the pressure-time curves and pressure rate−time curves are with four phases.

4. DISCUSSION

4.1. Influence of Rock Properties. To investigate the influence of rock property on hydraulic fracturing behavior, we conducted three comparison hydraulic fracturing tests with 300 × 300 × 300 mm cubic cement samples. The injection flow rate was set as 5, 15, and 30 mL/min. Temperature and triaxial confining stress conditions were the same as those of granite hydraulic fracturing tests. The breakdown pressures of the cement samples were 4.12, 6.26, and 14.32 MPa when the injection flow rates were 5, 15, and 30 mL/min, respectively. These breakdown pressures were obviously much lower than the breakdown pressure of granite samples in our experiment (Figure 9).

Figure 9. Photo of the fractured cement samples.

Usually, the rock strength of granite is stronger than other rocks, which are used for hydraulic fracturing, such as cement, shale, coal, and so on. Theoretically, rock reservoir with higher rock strength requires higher pump pressure to induce a hydraulic fracture, correspondingly it also leads to higher requirements for hydraulic fracturing system and fracturing scheme. Our experimental breakdown pressure results for the 300 × 300 × 300 mm cubic granite were between 22.12 and 36.01 MPa. For cement samples, the breakdown pressures were between 4.12 and 14.32 MPa. Our experiment results showed that the rock strength of cement samples are much lower than that of granite samples, this was consistent with...
previous studies. Fan and Zhang\textsuperscript{24} conducted hydraulic fracturing experiments on six artificial cement samples, all the breakdown pressures were between 8 and 20 MPa, the side lengths of the cubic samples were 300, 350, 400, 400, 450, and 500 mm, even though five of them were larger than the sample size of this study, none exceeds the breakdown pressures in this study. Wang et al.\textsuperscript{30} investigated the artificial cement hydraulic fracturing behavior to model sedimentary rock reservoir, and the injection flow rate was increased from 10 to 50 mL/min to crack seven artificial cement with 200 mm side lengths; the maximum breakdown pressure was 7.5 MPa. Dehghan et al.\textsuperscript{23} performed hydraulic fracturing experiments on 300 × 300 × 300 mm cement rock samples; the maximum breakdown pressure still did not exceed 20 MPa. Lin and Du\textsuperscript{31} mixed cement, coal, and plaster to make artificial cubic rock samples with 150 mm side lengths; even much lower breakdown pressures were detected, the breakdown pressures of the eight samples distributed between 1.51 and 4.54 MPa. Similar experimental results also were found in the studies of Fu et al.\textsuperscript{32} and Zhou et al.;\textsuperscript{33} in these two studies, no breakdown pressures of the cement samples exceeded 10 MPa. To increase the breakdown pressure of artificial cement samples and better simulate the hydraulic fracturing pressure condition in field, Fallahzadeh et al.\textsuperscript{16} increased the fracturing fluid viscosity with honey and polyethylene; when viscosity of the fracturing fluid was increased to 97700 CP, the breakdown pressure did not exceed 20 MPa, and when the viscosity was increased to 586,800 CP, the breakdown pressures of cement samples reached about 30 MPa, which was similar with the breakdown pressures of our experimental results.

In addition, Wang et al.\textsuperscript{34} conducted hydraulic fracturing experiments on shale samples; the breakdown pressures of the six samples did not exceed 15 MPa. Chen et al.\textsuperscript{35} conducted 10 hydraulic fracturing tests on shale; the breakdown pressures was distributed between 7.66 and 20 MPa. Bennour et al.\textsuperscript{36} used water, oil, and liquid CO\textsubscript{2} as fracturing fluid for hydraulic fracturing experiments on 12 shale samples; the maximum breakdown pressure was 16.44 MPa. Fan et al.\textsuperscript{37} tested the breakdown pressure of large cubic coal samples; results showed that the breakdown pressure were between 8.8 and 19.1 MPa. Hou et al.\textsuperscript{38} analyzed the hydraulic fracturing failure strength of coal; the breakdown pressure did not exceed 16 MPa. The breakdown pressures of shale and coal in previous studies were obviously much lower than the breakdown pressures of granite in this study. Therefore, the hydraulic fracturing experiment of shale and coal is different from that of granite; shale and coal belong to soft rock, and granite belongs to hard rock; the breakdown pressure of granite should be higher than that of shale and coal. This is in consistence with our experiment results and previous studies. As a result, it is unreasonable to substitute other rocks (e.g., cement, shale, and coal) for granite in the hydraulic fracturing experiment.

In field scale EGS operation, fractures often could be induced when the pump pressure reaches 25−35 MPa,\textsuperscript{39−41} which is very similar to the breakdown pressure in this study, and this indicates that hydraulic fracturing experiment with large scale intact granite is very necessary; the large intact granite experimental results are almost consistent with the actual in situ hydraulic fracturing pressure of the EGS, it will provide better guidance and reference for in situ hydraulic fracturing design.

4.2. Influence of Thermal Stress. Hydraulic fracturing for an EGS operation usually is performed in a deeply buried high-temperature granite reservoir; the thermal stress caused by high temperature will lead to the change of rock properties, and thus the hydraulic fracturing characteristics between room temperature (about 25 °C) and high temperature should be different. To investigate the influence of thermal stress on hydraulic fracturing behavior, a comparison experiment on room temperature was carried out without the effect of heat. The injection flow rate was set as 10 mL/min. The triaxial confining stress conditions were the same as those of hydraulic fracturing tests in high temperature. In the room temperature comparison test, the initiation pressure was 27.64 MPa, the breakdown pressure was 30.28 MPa, the postfracturing pressure was 14.12 MPa, and the propagation time was 545 s, whereas in the aforementioned high temperature test 2, the initiation pressure was 22.95 MPa, the breakdown pressure was 24.68 MPa, the postfracturing pressure was 12.69 MPa, and the propagation time was 498 s. The comparison experiment results showed that the initiation pressure, the breakdown pressure, the postfracturing pressure, and the propagation time increased by 20.44, 22.69, 11.27, and 9.44% under room temperature with the same injection flow rate and triaxial confining stress conditions. As a result, we could get the conclusion that high temperature can affect hydraulic fracturing behavior.

The reason of this phenomenon is induced microcracks at high temperature caused by thermal stress. A study conducted by Zhang et al.\textsuperscript{42} shows that the temperature definitely influences the mechanical and physical properties of the rock, and their results showed that when temperature was increased from 25 to 200 °C, their experimental rock strength would decrease from 8.7 to 5 MPa. The research of Nasseri et al.\textsuperscript{43} showed that the fracture toughness would decrease with the increase of temperature, which was caused by the gradual opening boundaries of the grains. According to the experimental observations of Shao,\textsuperscript{44} increasing the rock temperature could cause the thermal stresses in the rock matrix, and this would result in thermally induced cracks propagate along the boundaries of the weak grains and preexisting ones. The reason was the anisotropy of the rock matrix; the rock matrix was consisted of different mineral compositions and had different thermoelastic properties.\textsuperscript{45} The different minerals had different anisotropic expansion under high temperature, and this would lead to the localized stress concentration, once the concentrated stress exceeded the internal stress inside a particular mineral or the bond strength among different minerals, a microcrack would be initiated.\textsuperscript{46} The thermal induced cracks will lead to a reduction of the granite strength property. Because of the existence of microcracks, a lower injection pressure could initiate a fracture; as a result, the initiation pressure and breakdown pressure declined at high temperatures. At the same time, the existing microcracks reduce the fracture propagation resistance, the fracture propagation rate was accelerated, and then the propagation time would decline. The high temperature evaporated the water in the rock matrix, resulted in a large amount of microcracks; this made the rock became more fragile, and hence the postfracturing pressure was lower at high temperatures. Therefore, thermal stress at high temperatures reduces the rock strength and makes hydraulic fracturing easier.

4.3. Effect of Flow Rate on the Fracture Initiation Pressure. Usually, we call the maximum pressure as the breakdown pressure, and it seems that the rock sample is...
fractured and fails when the pressure reaches the maximum. However, the rock around the wellbore bottom already begins to be fractured before the maximum pressure. To properly make sure the fracturing initiation pressure is helpful to analyze the rock properties, such as failure stress, tensile stress, and shear stress in real field hydraulic fracturing, accurate estimation of fracturing initiation pressure is also essential for the hydraulic fracturing system efficient and effective design. It will directly influence the hydraulic fracturing method and difficulty in field-scale operations.

To find out the time of fracturing initiation, we first analyze the hydraulic fracturing process. Considering the moment at which the wellbore is full of fluids, the pressure will rise quickly. When enough fluid is pressurized, a fracture initiates from the wellbore bottom, and some new volume is expected to develop. The pressurized fracturing fluid in the wellbore expands to fill the volume of the newly initiated flaws, and consequently, the wellbore pressure decreases. This leads to a reduction in wellbore pressure. At the same time, the pressurized fluid will naturally quickly flow toward the wellbore to compensate for this pressure reduction. This may consequently provide higher pressure in the wellbore, but the wellbore pressure will not increase obviously. As a result, we can find that the highest fracturing pressure always lasts for a while in the fracturing pressure curve. This phenomenon will definitely cause a change of the pressurization rate. Then, the initiated fracture will propagate toward the sample boundary, and more volume is developed. When the pressurized fluid cannot compensate the newly induced volume, the pressure curve declines. When the fractures reach the sample boundary and the fluid flow out of the sample, the injection pressure becomes stable. The pressure does not fluctuate, and the pressurization rate gradually become zero.

Based on the analysis of the fracturing process, we find that the pressurization rate could be used to indicate the fracturing initiation, fracturing termination, and propagation time. In Figure 8a–f, the red curves are the pressurization rate curves. When the wellbore is not full of fracturing fluid, the pressure keeps at zero, and the pressurization rate is also kept at zero. Then, the pressurization rate rapidly rises and usually fluctuates in a constant value for a while at the top of the curve. In this period, fluid is full in the wellbore and still being pressurized into the wellbore, no fracture is initiated. As the flow rate is constant, the pressure rises approximately linearly with time, and the pressurization rate is almost constant with little fluctuations. The beginning of quick decline in the pressurization rate curve could be considered as the evidence of the fracture initiation point. As the rock in the wellbore bottom could not withstand high pressure, the fracture initiates, microcracks are initiated, and hence the wellbore pressure increasing rate decreases. This is due to the fact that the pressurized fracturing fluid in the wellbore expands to fill the volume of the newly initiated flaws, and the newly pressurized fluid cannot absolutely compensate the pressure reduction; consequently, the pressurization rate decreases. When the fracture tip is close to the sample boundary, the pressure is almost equal to fluid frictional pressure loss, and the pressurization rate rises and gradually becomes zero.

Based on the above analysis, the fracture initiation pressure could be estimated as the time when the pressurization rate begins to rapidly decrease, at which the fracturing pressure has not yet reached the maximum value (see Figure 8a–f). We can find that, from Figure 8a–f and Table 3, with the increase of the injection flow rate, the fracturing initiation pressure also increases, thereby indicating that injection flow rate influences the initiation pressure of granite hydraulic fracturing.

The initiation pressure of a granite sample under different injection flow rates is shown in Figure 10. As shown in Figure 10, the initiation pressure has an approximately positive linear relationship to the injection flow rate. For example, the initiation pressure increases from 21.06 to 32.52 MPa when the injection flow rate increases from 5 to 30 mL/min, and the initiation pressure increases by 54.42%. In addition, the initiation pressures were linearly fitted, and the coefficient of determination was found to be 0.9808.

4.4. Effect of Flow Rate on the Fracture Propagation Time. The accuracy of hydraulic fracturing pressure measurement depends strongly on an accurate interpretation of the fluid pressure-time recorded during the hydraulic fracturing tests. In development process of oil, gas, and EGS fields, the time of hydraulic fracturing will also directly influence the number and magnitude of the induced earthquakes.

In laboratory fracturing experiments, fracture propagation time is generally considered as the time interval it takes for an initiated fracture to grow from the wellbore all the way to the sample boundary. After the fracture is triggered, the fracture grows, more and more volume will be generated, and the wellbore pressure decline will accelerate. This is indicated in Figure 8, where the wellbore pressurization rates (red curves) decrease after the fracture initiation points. It could be considered as the beginning of the fracture propagation. When the fracture tip hits the boundary of the sample, the fluid will flow out of the sample. This means that the wellbore pressure is now equal to the fracturing fluid frictional pressure loss along the created fractures. Because this pressure loss does not change over time, the wellbore pressure will stabilize. This is the point where the pressurization rate becomes zero and fracturing pressure does not change. This point (see Figure 8) could practically be considered as the end of the fracture propagation, and the rest of the pressure-time data represents the fluid flowing through the whole fracture system. Through the pressurization rate curve, we can easily find out the propagation time. The fracture propagation time (see Figure 8) could be considered as the time interval between the fracture initiation and the fracture end.
The propagation time of a granite sample under different injection flow rates is shown in Figure 11. As shown in Figure 11 with the increase of injection flow rate, the propagation time has a linear decrease trend. The propagation time decreases from 613 to 88 s when the injection flow rate increases from 5 to 30 mL/min, and the propagation time decreases by 85.64%. In addition, the curves are linearly fitted, and the coefficient of determination is found to 0.9851. This relationship represents that with the increase of the injection flow rate, more fluid is pumped into the wellbore in the same time interval, more new volume is created, the fracture propagation rate also increases, and as a result, the fracture propagation time decreases when the rock sample size is the same.

Usually, induced earthquakes are accompanied with the whole hydraulic fracturing process; a longer fracture propagation time is always when more earthquakes are triggered. In an EGS project, a traditional view is that the maximum induced earthquake magnitude is only related to the total volume of the injected fluid. Therefore, to get a good fracture network and avoid a dangerous earthquake, a small injection flow rate with a long propagation is always adopted in the EGS field-scale operation in recent years. However, this method also could cause a large earthquake; for example, hydraulic fracturing of the Pohang EGS project almost lasted several months in about 2 years, a Mw 5.5 earthquake was caused, and this earthquake injured about 70 people and caused extensive damage in and around the city of Pohang. This earthquake was the most damaging and the second largest in magnitude in South Korea since the first seismograph was installed in 1905. As a result, it is necessary for hydraulic fracturing to choose a reasonable fracturing propagation time.

4.5. Effect of Flow Rate on the Postfracturing Pressure. The postfracturing pressure is almost a constant pressure behavior versus time after the fracture tip reaches the boundary of the sample; the length of the fracture does not increase any more. Such issues are marked and shown in Figure 8, where after the fracture reached the sample boundary, the rest of the pressure recording data is just showing the fracturing fluid flowing through the created fracture all the way to the boundary of the sample. The wellbore pressure remains almost constant. It should be noted that the postfracturing pressure behavior is very similar to the fluid injection pressure during the heating extraction phase after hydraulic fracture propagation phase ending in the field for an EGS project. This injection pressure (postfracturing pressure) is based on the concept of fluid flow through a fracture. When a fluid with a constant viscosity and under isothermal conditions is flowing through a constant length fracture, the frictional pressure loss along the fracture would not change over time. In an EGS project, the requirement for the hydraulic fracturing technology is very high. If the fractures are too developed (indicating a low postfracturing pressure), the water flows too fast in the fractures, the heat exchange time between the water and the rock is short, the heat transfer is insufficient, and the water temperature at the water outlet well is low. The thermal energy cannot be well-exploited. If few fractures propagate insufficiently or the fracture channel is narrow (indicating a high postfracturing pressure), the water cannot flow through the inlet wellbore to the outlet wellbore well, it may result in serious water loss or less water could flow out of the outlet wellhead. We will not yet achieve the purpose of thermal energy exploitation. Therefore, in hydraulic fracturing, we need properly propagated fractures; water not only can flow well in the fracture but also can have a good heat transfer with rock thermal reservoir along fractures. However, the fractures cannot be directly observed after hydraulic fracturing in field-scale operation, and we need to find other methodologies to interpret the fracturing pressures.

In laboratorial hydraulic fracturing experiments, the postfracturing pressure is the frictional pressure loss when fluid flow through the whole fracture system. It is in accordance with the injection pressure during the heating extraction phase in field and could directly reflect the fracture condition, and it is an important parameter to determine the heat extraction efficiency and evaluate the hydraulic fracturing results. As the injection flow rates are different in tests, the postfracturing pressures could not be used for analysis directly. To test the fracture network and contrast the postfracturing pressures in different tests, the flow rate is changed to 5 mL/min at the end of each test. If the flow rate is greater than the least flow rate, new fractures may be triggered for the samples whose flow rate (the flow rate in Table 3) is lower during the hydraulic fracturing experiment stage. So, we choose the lowest flow rate when revising the postfracturing pressures. Table 4 presents the postfracturing pressures when the flow rates are changed to 5 mL/min; they are called the revised postfracturing pressures. We can see that a higher injection flow rate during the experimental (hydraulic fracturing) stage, a lower revised postfracturing pressure is caused.

As shown in Figure 12, the revised postfracturing pressure decreases with the increase of the injection flow rate. The revised postfracturing pressure decreases from 11.2 to 1.43 MPa (a gradient of 87.23%) when the injection flow rate increases from 5 to 30 mL/min. We can see that a lower

![Figure 11. Influence of injection flow rate on the propagation time.](image-url)
revised postfracturing pressure corresponds to a lower injection flow rate after hydraulic fracturing, and a higher revised postfracturing pressure corresponds to a higher injection flow rate. This means that a lower injection flow rate may cause a fracture network with less fractures and narrow channels for water flowing through, whereas a higher injection flow rate may lead a developed fracture network that water could easily flow through.

The postfracturing pressure is an effective parameter during estimating fracture opening or leak off during hydraulic fracturing. It also could help to analyze the fracture geometry, length, and smoothness; a lower postfracturing pressure usually corresponds to a better-connected fracture network with longer and smoother fracture branches. The postfracturing pressure is an indispensable parameter when predicting the productivity of wells after hydraulic fracturing. Therefore, it is necessary to correctly identify the postfracturing pressure and find out its changing laws.

4.6. Effect of Flow Rate on the Fracture Breakdown Pressure. The fracture breakdown is usually defined as the time at which the wellbore pressure reaches its maximum value. Fracture initiation typically occurs before the breakdown point. The fracture-initiation pressure is the point at which a small initial defect at the borehole starts to propagate, and the breakdown pressure is usually larger than the fracture-initiation pressure. In general, we need to distinguish the initiation pressure and breakdown pressure when considering the problem of fracture propagation.

The breakdown pressure always occurs after the initiation pressure when the fracture is just initiated, and the newly created volume cannot compensate the injected fluid. The breakdown process reflects a situation where the fluid supply (the amount of fluid injected into the wellbore) is greater than the fluid demand (the fluid volume needed to propagate the fracture), and the wellbore bottom pressure continues to rise. A higher pressure (breakdown pressure) will be caused.

The initiation pressure represents the pressure when the fracture begins to be initiated. It is a parameter that could reflect the properties of the rock sample. The breakdown pressure is the peak value of the pressure cure, and it could use to help to design the fracturing scheme, select the fracturing pump, and estimate the fracture range in a field operation. Therefore, it is necessary to separately analyze the initiation pressure and the breakdown pressure, whether for laboratory research or field-scale engineering.

Figure 13 shows a change in trend of the breakdown pressure with the increase of injection flow rate. The breakdown pressure of the granite cubic sample is almost positively linear to the injection flow rate. The breakdown pressure increases from 22.12 to 36.01 MPa when the injection flow rate increases from 5 to 30 mL/min, and the initiation pressure increases by 62.79%. In addition, the curves were linearly fitted, and the coefficient of determination was found to be 0.9943.

The breakdown pressure is a very important parameter during the hydraulic fracturing process. Previous study also shows that it could influence the fracture propagation behavior and fracture geometry. The fracture approach mechanisms during the hydraulic fracturing stage is mainly controlled by the breakdown pressure. This parameter is widely used when analyzing the fracture behavior in laboratory tests, numerical simulation, and in situ project. As a result, it is crucial to correctly determine the breakdown pressure and analyze the changing trend with the injection flow rate.

4.7. Effect of Flow Rate on the Fracture Geometry. The fracture networks provide the pathway for fracturing fluid. The distribution of induced hydraulic fractures is of vital importance to the evaluation of hydraulic fracturing operation. The length, height, and morphology are important indexes to access the hydraulic fracturing results and investigate fracture extension patterns. To clearly observe these indexes of the fractures, the samples are cut in half (Figure 7b) at the bottom of the wellbore (in the middle of the sample). Figure 14a–f shows the fractures of test no. 1–6 samples. Table 5 presents a brief description of the fracture geometries.

It was expected that a fracture propagation direction would be vertical along the PFD, perpendicular to the direction of minimum stress. However, only the fractures in test 1 (Figure 14a) propagate almost along the PFD, and most of the others are initiated in an angle with respect to the PFD and propagated in a curved path away from the wellbore, and eventually, then the tip of the fractures grew toward the vertical plane. As it can be seen from Figure 14, fracture propagation in hydraulic fracturing is influenced by triaxial principle stresses (crustal stress in field). The fractures always propagate along the direction which is perpendicular to the minimum stress. Although sometimes the fractures are not along the PFD near the wellbore, the fractures will gradually turn to PFD in curved paths as the fractures grow toward the boundaries of the samples. The reason is that the actual stress state near the
The initiation of hydraulic fracture is controlled by the in-situ stress, the wellbore, the wellbore internal pressure, the pore pressure, the rock stress condition, the rock anisotropy, and other mechanisms. As a result, the fractures may be not along the PFD at first. Once some fracture length is created, the rate of fracture propagation will stabilize. When the tip of the fracture is moving far from the wellbore and perforation stressed zone, it is approaching a less stressed region (concurrently, the wellbore pressure is now less than the breakdown pressure; therefore less pressure is provided in the fracture for the purpose of its propagation), and then the fracture propagation will be controlled by the triaxial stresses and along the PFD.

We can also see that in tests 4, 5, and 6, some fracture branches still do not approach the PFD when they reach the rock boundary, even parts of them are perpendicular to the PFD. As shown in Figure 14d–f, some of the main fractures, that propagate from the wellbore, cannot be seen to turn toward the PFD when the fracture tips hit boundary. Fan and Hannes et al. performed a series of studies and show that as the injection flow rate increased, the balance between fluid injection and propagation could be broken, and the fracture propagation would become unstable and fluctuated; this meant that the fracture propagation pathway might be unpredictable. Sometimes, in the area around the wellbore, the fracture propagation would not obey the PFD law. This is in accordance with our experiment results. As higher injection flow rates translate to higher injection pressures and more energies available for rock failure near the injection well, more energy is introduced into the rock, and the chances of creating a complicated fracture network are increased. The reason is that, when a large amount of water is injected into the well in a short time, a high-pressure environment is formed rapidly at the bottom of the well; this will lead the fracturing process similar to an explosion process, and the fractures propagate rapidly from the well to the rock boundary, and the hydraulic fracturing time is very short. As the energy and pressure are released rapidly, this kind of "exploded" fracture propagation pattern always trigger new tension fractures, and as a result, the fractures may not propagate along the PFD. However, when the injection flow rate is low, the fractures propagation rate is low either, the fractures tend to be shearing ones, shear
Table 5. Fracture Geometry Description

| Test no. | Injection Flow Rate (mL/min) | Total Length of Fractures (mm) | Fracture Geometry Description |
|----------|-------------------------------|--------------------------------|-------------------------------|
| 1        | 5                             | 319                            | In Figure 14a, only a two wing fracture is propagated along the PFD, that is the maximum stress axis direction, the fracture is almost perpendicular to the direction of the minimum stress. |
| 2        | 10                            | 342                            | In Figure 14b, only a two wing fracture is propagated. The upward fracture and downward fracture have angles of about 15.4° and 19.2° with the PFD, respectively, the propagation angles are small, and the fractures are considered along the PFD. |
| 3        | 15                            | 467                            | In Figure 14c, a two wing fracture and a single wing fracture are propagated. The upward fracture propagation angle is 30°, which is larger than the two downward ones (14.8° and 19.44°). As the angles are less than 45°, the angles are closer to the maximum stress axis, and the downward fracture in left propagates a short path then turns toward the PFD. As a result their propagation directions could be considered as along the direction of maximum stress. |
| 4        | 20                            | 388                            | In Figure 14d, only a two wing fracture is propagated. The fracture propagates downward and upward both in a curved path and in a distance away from the wellbore the upward fracture turns toward PFD. The downward fracture could not be obviously observed toward PFD. |
| 5        | 25                            | 1089                           | In Figure 14e, three wings are initiated from the wellbore. The wing that propagates to the upper left has an angle of 34.3° near the wellbore. Then, the upper right one changed its direction toward the PFD. The lower left one propagates into three branches away from the wellbore, and two of them develop toward the PFD and merge upward into one fracture. The downward branch propagates along the PFD at first and then develops against the maximum stress at the lower edge of the sample. |
| 6        | 30                            | 1386                           | In Figure 14f, this test exhibited a multiple fracturing distribution, a fracture system with three wings are initiated from the wellbore. The upward wing propagates almost along the PFD. The upward one is the widest fracture and could be considered as the main hydraulic fracture. However, its three branches are almost against the PFD. The left downward wing is initiated along the PFD and then grows in a curved path to the lower left, and its only branch propagates against the PFD. The right downward wing is initiated against the PFD at first and then its branch propagates along the PFD. |

Figure 15. Influence of Injection Flow Rate on the Fracture Length.

Generally speaking, the fracture length increases with the increase of the injection flow rate. However, we can see that the fractures in test 4 are wider, and the length of the fractures in test 4 is less than that in test 3. Combined with Figure 14b, from the enlarged fracture photo, we can see that the fractures in test 4 are wider, and the corresponding fluid propagating pressure in test 4 is lower; this means that the fluid propagating pressure in test 4 is lower than that in test 3 when the fluid propagates through the fracture system.

The increase of the injection flow rate leads to higher injection pressures, wider fractures, and more complex fracture system. This results in a higher connectivity of the fracture system. This results in a higher permeability and a higher fracture conductivity. A more complex fracture system may allow more fluid to flow through the fracture system, which results in a higher permeability and a higher fracture conductivity. A more complex fracture system may allow more fluid to flow through the fracture system, which results in a higher permeability and a higher fracture conductivity.
fractures and a lower friction resistance for fluid flowing. The revised postfracturing pressure in Table 4 is in accordance with this conclusion.

When the injection flow rate increased from 5 to 20 mL/min, the total length of fractures increased, but the increase trend, as shown in Figure 15, was not obvious. When the injection flow rates were increased to 25 and 30 mL/min, the total lengths of fractures have a notable increase. Combined with Figure 14, the fractures in tests 1, 2, 3, and 4 (injection flow rate from 5 to 20 mL/min) formed a two-wing or a three-wing fracture; a fractured network in these tests was not induced. As a result, the increase of the injection flow rate only increased the fracture width but not in the fracture length. This means the fractures in tests 1–4 should be mainly shear fractures. When the injection flow rate was increased to 25 mL/min (test 5) and 30 mL/min (test 6), the “exploded” fracturing mode is triggered; the fractures were mainly tension fractures. Fracture networks formed in the both tests, and hence the fracture lengths had an obvious increase. It shows that when the injection flow rate is low, the shear fractures are induced, and the hydraulic fracturing usually forms a main fracture without branches. When the injection flow rate is high enough, the tension fractures could be triggered, and the hydraulic fracturing could form a fracture network.

4.8. Mean Injection Power. Figure 15 shows the relationship between the injection flow rate with the total length of fractures, although by increasing the injection flow rate, longer fracture length were induced, and the relationship between the two parameters could not be obtained from Figure 15.

To analyze the reason whether the injection flow rate could influence the geometry, width, and complexity of fractures and why a higher fluid injection flow rate usually causes a more complex fracture system, a new parameter called mean fracturing power ($P_{\bar{i}}$) is put forward. Each test has a specified flow rate ($Q$), and the fracturing pressure ($P$) varies as a function of time ($t$). Considering the unit of injection flow rate (m$^3$/s), the unit of hydraulic fracturing pressure (N/m$^2$), and the unit of time (s), it is realized that the unit of the product of flow rate, fracturing pressure, and time will be N·m. This means that the product represents the energy which is supplied for hydraulic fracturing. Hence, the $P_{\bar{i}}$ is defined as:

$$P_{\bar{i}} = \frac{\int_0^T Q \cdot P \, dt}{T}$$  \hspace{1cm} (1)

where $T$ is the fracture propagation time. The unit of $P_{\bar{i}}$ is power (W).

Table 6 shows the mean fracturing power of test no. 1–6.

The relationship between the mean fracturing power and the total length of fractures is shown in Figure 16. The mean fracturing power has a good positive linear relationship withnow rate usually causes a more complex fracture system, a new parameter called mean fracturing power ($P_{\bar{i}}$) is put forward. Each test has a specified flow rate ($Q$), and the fracturing pressure ($P$) varies as a function of time ($t$). Considering the unit of injection flow rate (m$^3$/s), the unit of hydraulic fracturing pressure (N/m$^2$), and the unit of time (s), it is realized that the unit of the product of flow rate, fracturing pressure, and time will be N·m. This means that the product represents the energy which is supplied for hydraulic fracturing. Hence, the $P_{\bar{i}}$ is defined as:

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Table 6 shows the mean fracturing power of test no. 1–6.

The relationship between the mean fracturing power and the total length of fractures is shown in Figure 16. The mean fracturing power has a good positive linear relationship with the fracture total length, and the coefficient of determination was found to be 0.9052. In most circumstances, especially in field, fractures cannot be observed and measured directly. In addition, the fracture length is the most important parameter to evaluate the hydraulic fracturing effect. Previous methods for the evaluation of hydraulic fracturing are usually the drilling, micro-earthquake, and magnetotelluric methods, and these measurement methods sometimes cannot be used in field due to high cost. As a result, estimating the fracture length is always a challenging work in field-scale hydraulic fracturing. The fracture total length is roughly positive increase with the mean fracturing power; hence we can use this relationship to roughly evaluate the fracture length in field with almost no cost. This linear relationship provides us with a new way to roughly predict fracture length.

4.9. Permeability of the Hydraulic Fracture. Up to now, hydraulic fracturing is an imperative technique for economic exploitation of deep geothermal resources by enhancing reservoir rock permeability. Therefore, it is important to understand the permeability after hydraulic fracturing. Patel et al.72 proposed a method to estimate fracture permeability using pressure data recorded during hydraulic fracturing. The method hypothesizes that the drop in the injection pressure just after the breakdown during hydraulic fracturing occurs due to the flow of injected fracturing fluid inside the induced hydraulic fracture. This hypothesis is in accordance with our aforementioned pressure drop effect. Previous methods to determine the permeability of the hydraulic fracture have considered the fracture as a straight, thin, and permeable plate.

$$\frac{\partial P}{\partial t} - D \frac{\partial^2 P}{\partial z^2} = 0$$  \hspace{1cm} (2)

The solution to eq 2 is given by eq 3.

![Figure 16. Influence of mean fracturing power on the fracture length.](https://dx.doi.org/10.1021/acsomega.0c00172)
\[ \Delta P(z,t) = P_0 \exp \left( \frac{-z}{\sqrt{4Dt}} \right) \] (3)

where \( P_0 \) is the breakdown pressure, \( z \) is the length of the fracture, \( D \) is the hydraulic diffusivity, and \( t \) is the time after the breakdown. Equation 3 can be modelled to fit the actual recorded pressure curve, and the hydraulic diffusivity can be estimated because \( P_0, z, \) and \( t \) are known. The permeability can be estimated from the hydraulic diffusivity by using eq 3 given by Shapiro et al.\textsuperscript{73}

\[ D = \frac{NK}{\mu} \] (4)

where \( K \) is the permeability, \( \mu \) is the dynamic viscosity of the fluid, and \( N \) is defined as

\[ N = \frac{MP_d}{H} \] (5)

where,

\[ M = \frac{1}{\phi} \left( \frac{1}{K_i} + \frac{(\alpha - \phi)}{K_s} \right) \] (6)

\[ \alpha = 1 - \frac{K_i}{K_s} \] (7)

\[ H = P_d + \alpha^2 M \] (8)

\[ P_d = K_d + \frac{4}{3\mu_d} \] (9)

Here, \( K_{id} \) is the bulk moduli of the fluid, dry frame, and grain material, respectively; \( \mu_d \) is the shear modulus of the frame; and \( \phi \) is the porosity.

Based on eqs 2–9, the fracture permeability could be calculated by using hydraulic fracturing pressure curves of the six granite rock samples. The values of \( K_0, K_p \), and \( K_d \) used to calculate the permeability are 2.18, 75, and 28.09 GPa respectively. The values of \( \mu_d \) and \( \phi \) used for calculation are 15.58 GPa and 0.0395 Pa-s, respectively. The value of \( \mu \) is 0.0001863 Pa-s.

The permeability was 0.92, 1.21, 2.23, 3.32, 5.72, and 7.54 mD when injection flow rate was 5, 10, 15, 20, 25, and 30 mL/min, respectively. The value of estimated fracture permeability with the injection flow rate is plotted in Figure 17. The fracture permeability shows a positively ascend trend with the increase in the injection flow rate. This means that a higher injection flow rate will cause wider, lager fractures. All of the rock sample permeability after hydraulic fracturing is greater than the original sample permeability. As the original permeability is 0.34 mD, the permeability is obviously promoted. When the injection flow rate increases by 5 mL/min every time, compared with the original sample permeability; the permeability is increased 1.71, 2.55, 5.56, 8.78, 15.81, and 21.21 times. When the injection flow rate is 30 mL/min, the permeability is the highest. In the field-scale operation, we usually trend to create more fractures and form higher permeability, and a higher injection flow rate is better. At the same time, this also puts forward higher requirements for technology and equipment, and it may require more cost and more advanced equipment; hence the maximum permeability as the primary consideration may be not economical and reasonable. Therefore, in the process of hydraulic fracturing, it is necessary to consider fracturing scheme carefully, and the injection rate can not only form a good fracture network, obviously improve permeability, but also ensure a reasonable cost. For example, for the five fracturing injection rates selected in this experiment, the 25 mL/min can be considered as the best. Although 5, 10, 15, and 20 mL/min increased the permeability to a certain extent, the magnitude of the permeability is not increased higher enough, a fracture network is not formed, and the hydraulic fracturing effect is not obvious, whereas 30 mL/min obtained the maximum permeability, compared with the permeability result of 25 mL/min, the permeability is increased 31.82%; this promotion is not obvious enough. Considering the cost of a field operation, this increase is unworthy; so the injection rate of 25 mL/min can be regarded as the best; of course, this conclusion is only the based on the experimental results. In field, more factors should be considered when selecting a reasonable injection flow rate.

Patel et al.\textsuperscript{72} calculated hydraulic fracturing permeabilities, which are 2.28, 2.58, and 5.69 mD, when hydraulic diffusivities are 0.00086, 0.001075, and 0.00215, respectively. The estimated fracture permeabilities were compared with the fracture permeabilities measured by using AP608 permeability test apparatus. Solberg et al.\textsuperscript{74} considered the hydraulic fracturing of a low permeability sandstone rock at different injection rates. They conducted permeability measurements both before and after hydraulic fracturing experiments. Results show that increased permeability is produced by permanent structural changes in the rock. The permeabilities are 0.38, 5.99, 24.89, and 13.76 nm\(^2\) when pumping rates are 3.0, 15, 30, and 70 mm\(^3\)/s. Results show that the estimated permeability values come in close agreement with the measured ones. Our experimental conclusions were therefore consistent with the data obtained by Solberg and Patel et al.

5. APPLICATIONS FOR GEOTHERMAL ENERGY EXTRATION

The EGS has the potential to enable economic recovery of energy from underutilized HDR reservoirs or increase production from conventional geothermal reservoirs. The natural permeability of geothermal reservoirs is typically low and therefore needs to be enhanced to enable efficient use and economic viability. Hydraulic fracturing is a promising stimulation method for improving fluid flow, in situ permeability, and heat extraction in EGS. It offers a means...
for stimulation that fluid is injected with sufficient rate and pressure to create new fractures. This method allows the fluid sustained injection and circulation through the reservoir for heat energy commercial extraction. Our experimental results have showed that high injection rates can lead to a complex induced fracture network. At the same time, high injection rates also correspond to high breakdown pressures, high initiation pressures, short propagation times, and low revised post fracturing pressures, and the initiation pressures could be used to estimate rock failure stresses; the post fracturing pressures, and the initiation pressures are related to the induced earthquakes; the post fracturing pressures influences the heat extraction efficiency. Therefore, we can not only consider breakdown pressure when designing fracturing scheme but also consider the influence of different parameters on the fracturing results, such as induced earthquakes and heat extraction efficiency when choosing injection flow rates in field.

Because of the limitation of the experiment conditions, there are some shortcomings in the present experimental study; for example, as just mentioned, even if we know the injection flow rate is not the higher the better, we do not know how to choose an injection flow rate and how much permeability is optimal. This work needs further efforts. In addition, communication of existing fractures is also part of the hydraulic fracturing in the EGS and is not covered in this study.

6. CONCLUSIONS

In this paper, we use a true-triaxial apparatus to conduct an intact large-size 300 × 300 × 300 mm granite sample hydraulic fracturing experiment under high temperature and triaxial confining stress conditions. Hydraulic fracturing characteristics are experimentally investigated by varying the injection flow rate. According to the injection pressure curves, pressurization rate curves, and fracture morphology, we analyze the fracture initiation pressure, propagation time, postfracturing pressure, breakdown pressure, fracture geometry, and length. The fracture permeability is calculated at last. Based thereon, the following conclusions are obtained:

(1) The large intact granite experimental results could be used to guide in situ hydraulic fracturing operation. The EGS high-temperature environment causes thermal stress in granite, and this reduces the rock strength of granite and makes hydraulic fracturing easier.

(2) The injection flow rates significantly influence the fracture initiation pressures, propagation times, post-fracturing pressures, and breakdown pressures during hydraulic fracturing. The initiation pressures and breakdown pressures have approximately linear positive relations to injection flow rates. The postfracturing pressures and propagation times have approximately linear negative relations to injection flow rates.

(3) Even though the fracture propagation direction sometimes is not along the PFD near the wellbore zone because of the complex stress state, the fracture propagation direction is influenced by triaxial stresses (crustal stress in field) and will gradually turn to PFD when the fracture tip is far away from the wellbore.

(4) When the injection flow rate is low, mainly shear fractures are induced, the hydraulic fracturing may not cause a fracture network. As the flow rate increases, when the tension fractures dominate fracturing patterns, the hydraulic fracturing tend to form a fracture network.

(5) A higher injection flow rate means more energy is exerted to the granite sample, and a more complex fracture network is apt to create. The total length of the fractures almost linearly increases with the increase of mean injection power, and this linear relationship provides us with a way to roughly predict fracture length.

(6) The fracture permeability of samples after hydraulic fracturing shows a linear ascending trend with the increase of the injection flow rates.

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Notes

The authors declare no competing financial interest.

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