

In this issue

Co-Editors' Note

- 2 Geothermal: The Next Energy Powerhouse
- 5 FORGE
- 9 Geothermal Plants in Latin America
- 14 A Review of the Development and Utilization of Geothermal Energy Resources in China
- 20 Modeling of EGS reservoir Stimulation at Utah FORGE Site
- 23 Conductive Heat Mining
- 25 Thermo-poroelastic Effects in Geothermal Reservoir Stimulation
- 30 Short Circuiting Mechanisms in Hot Dry Rock Geothermal Methods
- 33 Channeling in Enhanced Geothermal Systems
- 38 Induced Seismicity in Low-Temperature Geothermal Development
- 40 In-situ Stress Measurements at the Utah FORGE Site
- 44 Successful Implementation of HT Geothermal Drilling Technology
- 47 ORCHYD: A Fluid-driven Drilling System Combining Water Jetting and Hammer Drilling for Cheaper Geothermal Drilling

Co-Editors' Note

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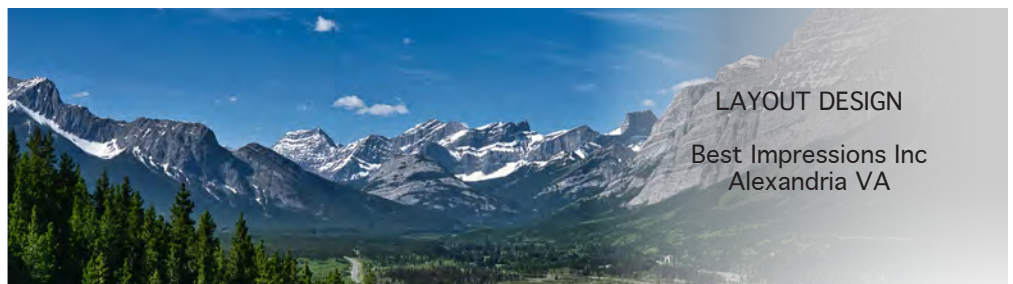
From its start in 2010, ARMA LETTERS has intended to present informative and useful information to the academics, practitioners, corporate members, and others that make up the rock mechanics-geo-engineering community. The research, development, and practices of this scientific and technological group are recognized for presenting interdisciplinary inquiries and practices. Many of the ARMA LETTERS topics have reflected that technical breadth and integration of areas of knowledge.

Given this background, when the opportunity arose to serve as co-editors of an issue of LETTERS focused on geothermal research, development, and technical applications, we responded enthusiastically. The result is the 2022 Winter issue of LETTERS.

The articles encompass a variety of perspectives: overviews of the discipline, surveys of regional and country-specific initiatives, funding and other support programs, technical aspects, and innovations.

We hope that readers will find that these articles provide informative, useful, and even provocative information to the ARMA community. We have enjoyed this effort, and hope you find the same as you read this issue.

Maurice Dusseault, University of Waterloo | John McLennan, University of Utah



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Geothermal: The Next Energy Powerhouse

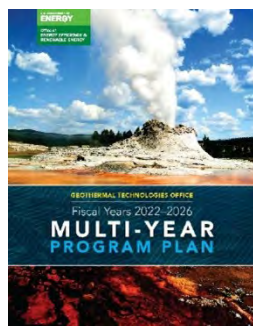
Submitted by Susan Hamm, Director, Geothermal Technologies Office, U.S. Department of Energy

Geothermal energy -- the “heat beneath our feet” -- is a firm, flexible source of clean, secure, and reliable domestic energy that can be utilized across industrial, commercial, and residential sectors. Geothermal energy offers important benefits, including grid stability, greater diversity of affordable energy options, efficient heating and cooling, key technology and workforce pathways from oil and gas to renewable geothermal development, and lower carbon emissions. It will help transition the nation to a carbon pollution-free power sector by 2035 and a net-zero emission economy by 2050, while ensuring the clean energy economy benefits all Americans.

The U.S. DOE’s Geothermal Technologies Office: A Quick Overview

The Geothermal Technologies Office’s (GTO) vision is a vibrant domestic geothermal sector that contributes to a carbon pollution-free electric sector and a net-zero emission economy while providing economic opportunities and environmental benefits for all Americans. The GTO mission is to increase geothermal energy deployment through research, development, and demonstration (RD&D) of innovative technologies that enhance exploration and production. Expanded geothermal deployment will deliver more affordable, low-carbon energy to Americans and create long-term, well-paying U.S. jobs.

GTO recently released its five-year Multi-Year Program Plan (MYPP), covering Fiscal Year (FY) 2022 through FY 2026, to serve as an operational guide to help GTO strategically plan and execute research and development activities and serve as a resource to help communicate to stakeholders and the public GTO’s five-year priorities and opportunities. In the plan, GTO outlines the following three strategic goals that serve as the basis of its research portfolio on the pathway to boost geothermal deployment.



GTO Strategic Goals

Strategic Goal 1: Drive toward a carbon-free electricity grid by supplying 60 GW of enhanced geothermal systems (EGS) and hydrothermal resource deployment. Aggressive technology improvements in EGS and hydrothermal resources combined with reduced permitting and regulatory timelines will enable significant deployment of geothermal electric generation and will provide essential firm, flexible capacity to support a carbon pollution-free electric sector by 2035 and deliver a net-zero emission economy by 2050.

Strategic Goal 2: Decarbonize building heating and cooling loads by capturing the economic potential for 17,500 geothermal district heating (GDH) systems and by installing geothermal heat pumps (GHPs) in 28 million households nationwide. Widespread adoption of GDH and GHP technologies in residential and commercial buildings will require transformational improvements in the economic accessibility; federal, state, and local tax incentives; social acceptance; and permitting and regulatory timelines. Geothermal heating and cooling technologies provide a step-change in building efficiency, reduce peak heating and cooling loads, and reduce stress on the bulk power system to meet the administration’s goal to reduce the carbon footprint of the U.S. building stock by 80% by 2035 and deliver a net-zero economy by 2050.

Strategic Goal 3: Deliver economic, environmental, and social justice advancements through increased geothermal technology deployment. Geothermal technologies create clean energy jobs and generate substantial local economic activity, including wage spending, land-lease payments, property taxes, royalties, and other important cumulative expenditures. Geothermal energy addresses environmental and social justice issues because its high capacity factor, small physical footprint, and wide-ranging applications ensure that it can be utilized in urban centers, rural areas, and remote communities. GTO will continue to document and amplify the benefits that geothermal can have for communities nationwide.

GTO will meet these strategic goals through research, development, demonstration, and deployment in six research areas. The research

areas, listed below, will provide enough structure to guide research activities while allowing GTO to adapt to changing market and technology conditions. Progress in each of these areas is critical to meeting the promise of geothermal energy in both the electric and heating and cooling sectors.

Exploration and Characterization: The high costs and risks associated with geothermal exploration are a major barrier to expanded development of both conventional hydrothermal and EGS resources. This research area focuses on technology and cost improvements for geothermal resource characterization during early exploration phases, which will improve resource targeting for all geothermal resource types and holds significant potential to improve project economics. This research area intends to address challenges and barriers that include cost-prohibitive data collection, limited public data availability, and low subsurface spatial resolution of data in support of strategic goal one. One current project in this area is the GeoFlight: Salton Trough initiative, a collaborative effort between GTO and the U.S. Geological Survey that collects data on hidden geothermal systems in California's agriculturally rich Imperial Valley.

Subsurface Accessibility: Subsurface access through drilled and completed wells is required for all forms of geothermal energy exploration, characterization, and development. This research area encompasses efforts to reduce the time and cost associated with the drilling of geothermal wells, ultimately meeting the key objective of achieving the "ideal" drilling cost curves used in the GeoVision analysis Technology Improvement scenario. Efforts in this area include investments that enable tools and other hardware capabilities that are more resilient in the extreme environments associated with drilling and producing geothermal reservoirs. This research intends to meet the challenges and overcome the barriers around drilling in high-temperature, hard, fractured rock formations. GTO recently released a new Drilling Demos funding opportunity that will support field demonstrations to provide measurable improvements to drilling time.

Subsurface Enhancement and Sustainability: Achieving aggressive EGS and hydrothermal resource deployment will require improving sub-economic naturally occurring hydrothermal

systems or developing fully engineered geothermal reservoirs. This geothermal energy recovery must be enhanced and sustained over project lifecycles in order to optimize geothermal energy, requiring significant RD&D efforts. This research area intends to meet the challenges and overcome the barriers to high reservoir stimulation technology costs and limitations to existing numerical models, ensuring enhanced and sustained geothermal energy. With funding from the Bipartisan Infrastructure Law (BIL), GTO will be supporting new EGS demonstrations across the country during the next few years.

Resource Maximization: Geothermal resources contribute towards U.S. grid reliability, resilience, and security; support development of a robust domestic clean energy manufacturing supply chain; and provide effective alternatives to grid-dependent heating and cooling as well as energy storage solutions for the built environment. This research area intends to develop and deploy new technologies, capabilities, as well as operational activities that maximize geothermal resources while instilling geothermal value recognition across the spectrum of use cases. Through the Geothermal Lithium Extraction Prize, GTO is helping fast-track efforts to identify, develop, and test solutions to improve the economics of extracting lithium, a critical mineral for renewable energy technologies, from geothermal brines.

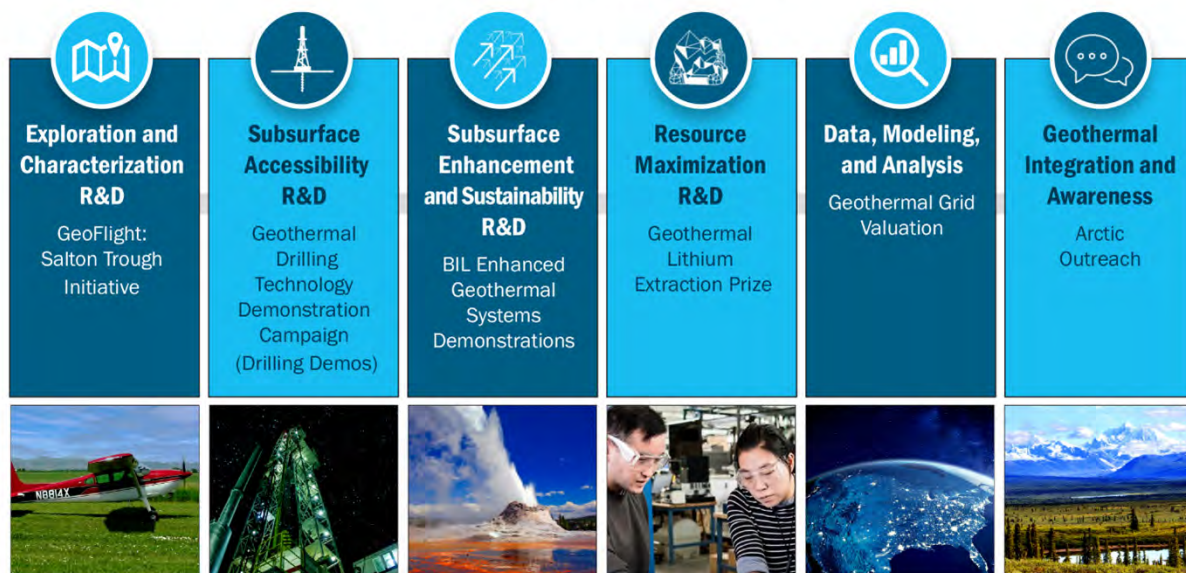
Data, Modeling, and Analysis: Data underpin RD&D conducted across all the research areas. Ensuring the quality and quantity of such data is critical to support effective data dissemination in DOE-developed technology and cost models, used to conduct strategic analyses that identify emerging GTO research opportunities, as well as tracking program-wide progress toward meeting metrics and goals. The Data, Modeling, and Analysis area intends to build on these activities by providing critical support and enabling functions in data best practices, modeling, strategic analysis, and outreach and communication that advance all the research areas. Geothermal grid valuation, one activity in this research area, focuses on better understanding how geothermal can enable rapid decarbonization of the electricity grid. There is a need for more robust datasets on geothermal technology performance and cost, as well as improved representation of geothermal technologies within grid projection and energy planning models.

Geothermal Integration and Awareness: This research area spans technology, workflow, commercialization, and stakeholder engagement activities. These include using machine learning techniques in RD&D activities, incorporating advanced manufacturing innovations for geothermal technology development, active support of geothermal technology commercialization, and promotion of trust in federal government messaging and opportunities. Additionally, integration of oil and gas infrastructure, workforce, and knowledge into the geothermal industry -- as well as broader geothermal community and engagement with key stakeholders, such as states and communities -- on the benefits and myriad applications of geothermal energy will build awareness and support for geothermal development opportunities. As part of this research area, GTO is currently helping Alaska communities explore using geothermal to meet their energy needs.

2015 to a request of \$163.7M for FY 2022). In addition, GTO received a single-year infusion of \$84M, through BIL, to provide funding for additional programs and researchers and expand GTO's support of demonstration projects, which are inherently riskier and more expensive than more basic and applied R&D.

GTO uses several competitive mechanisms to engage researchers in its programs, most commonly funding opportunity announcements -- which are aimed at researchers from a wide variety of organizations; lab calls, aimed at the DOE national laboratories; and prizes, which target industry, academia, and other organizations. In addition, GTO funds smaller awards through the Small Business Innovative Research and Small Business Technology Transfer programs and the Technology Commercialization Fund. Please see the resource list (Page 5) for additional information on these programs.

GTO Research Areas



GTO Budget and Funding Opportunities

GTO prioritizes its spending to meet its strategic goals, mission, and vision. Funding for GTO-supported research comes from the U.S. Congress through annual appropriations. The two relevant appropriations subcommittees are the House Energy and Water Development subcommittee and the Senate Energy and Water Development subcommittee. GTO's budget has increased significantly in recent years (from \$55M in FY

Applications for funding are typically rated by multiple independent external subject matter expert reviewers against a set of published merit review criteria, including technical merit, product research and market transformation plans, and the strength of the team and resources. Applications are then reviewed against a set of published program policy factors by a government-only Federal Consensus Board. GTO consistently looks for, among other factors, diversity in technologies being investigated,

geographic distribution, and types and sizes of applicant organizations; the degree to which a proposed project incorporates diversity, equity, and inclusion elements; and the level of industry involvement and a demonstrated ability to accelerate commercialization and overcome key market barriers. Review criteria may change depending on the specific funding opportunity. Current funding opportunities can be found on DOE's website and on EERE Exchange; to stay up to date on funding opportunities, please sign up for updates. Links are available below.

Resource List

For more information on topics presented above, please see the following links:

- Bipartisan Infrastructure Law: <https://www.energy.gov/bipartisan-infrastructure-law>
- EERE Exchange <https://eere-exchange.energy.gov/>
- Geothermal Technologies Office: <https://www.energy.gov/eere/geothermal/geothermal-technologies-office>; subscribe to receive updates
- *Geothermal Technologies Office FY 2022-2026 Multi-Year Program Plan*: <https://www.energy.gov/eere/geothermal/articles/geothermal-technologies-office-multi-year-program-plan-fy-2022-2026>
- *GeoVision: Harnessing the Heat Beneath Our Feet* and accompanying documents: <https://www.energy.gov/eere/geothermal/geovision>
- GTO Monthly Newsletter—The Drill Down: <https://www.energy.gov/eere/geothermal/geothermal-technologies-office-open-funding-opportunities>; subscribe to receive new editions.
- GTO Open Funding Opportunities, including Prizes: <https://www.energy.gov/science/sbir/small-business-innovation-research-and-small-business-technology-transfer>
- Small Business Innovative Research and Small Business Technology Transfer programs at DOE: <https://www.energy.gov/technologytransitions/technology-commercialization-fund>
- Technology Commercialization Fund program at DOE: <https://www.energy.gov/technologytransitions/technology-commercialization-fund>

FORGE: Frontier Observatory for Research in Geothermal Energy

Submitted by Joseph Moore, Stuart Simmons, Phil Wannamaker, Kristine Pankow, Penjgu Xing, Clay Jones, and John McLennan, University of Utah; and Robert Podgorney, Idaho National Laboratory.

Conventional, hydrothermal geothermal producers rely on three attributes: adequate thermal energy within an economical drilling window, natural fractures, and abundant hot fluid to convect through these natural fractures (or faults) to a production well and subsequently a power plant at the surface. On a geologic scale, conventional geothermal systems can be thought

of as simple convection cells with a heat source, recharge that is predominantly of meteoric origin, and a region of upflow. Fluid circulation is facilitated by the density differences between cold recharge (fluids reinjected at the surface after thermal energy is converted to electrical energy) and hot upflow through the natural fractures to a production well. Geothermal systems with temperatures greater than 250°C have magmatic heat sources. These hydrothermal operations are characterized by large in situ fluid volumes, convective thermal regimes, and extensive fracture systems -- although production tends to be from relatively few high hydraulically conductive fractures. Commercial wells require, at a minimum, flow rates greater than 40 liters/second. Historically,

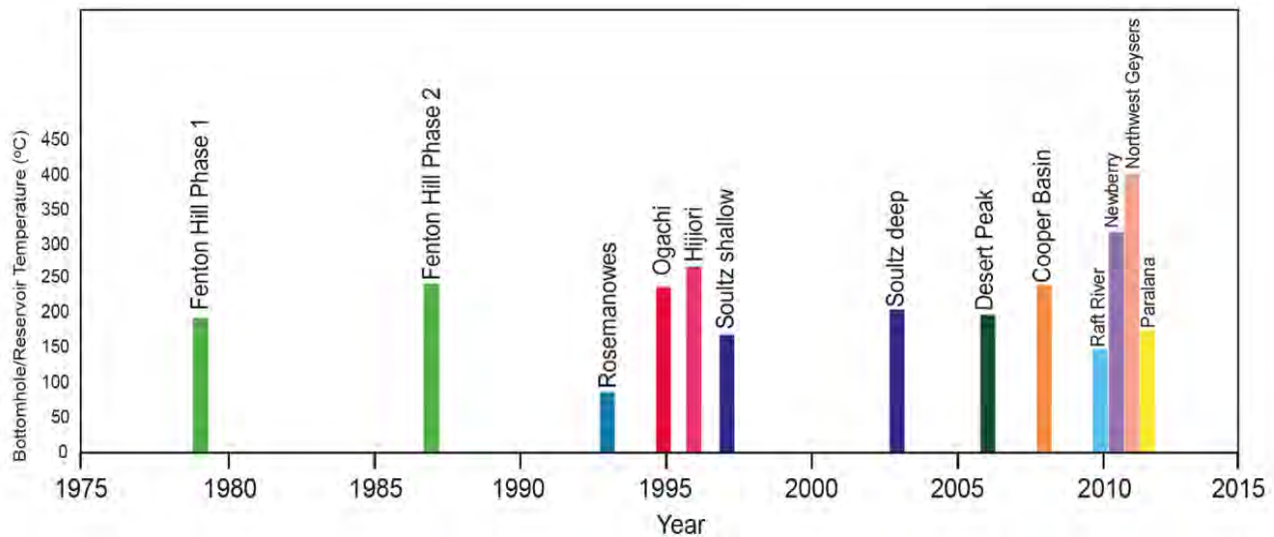


Figure 1. A compilation of EGS or hybrid EGS pilots and projects. Compiled from Tester et al., 2006[1], and Breede et al., 2013[2].

production is associated with only low magnitude seismic events. As indicated, injection is required to maintain reservoir pressures. Thermal cooling results in increased injectivity over time.

Commercial conventional energy extraction is restricted to geologically discrete parts of the earth where the three favorable conditions (heat, fractures, fluid supply) occur concurrently. The technology of Enhanced Geothermal Systems (EGS) has been considered, for more than a

half-century, as a platform to overcome this geologic discrimination. Consider a play where heat is present at reasonable drilling depths, but there are few significant fractures or faults (a conductive thermal regime) and there is no connate water or finite connection to water. Many areas throughout the world qualify for this. EGS exploits this heat by adding the two missing elements -- hydraulically or thermal generating fractures joining two or more wellbores to form a heat exchange system, and circulation

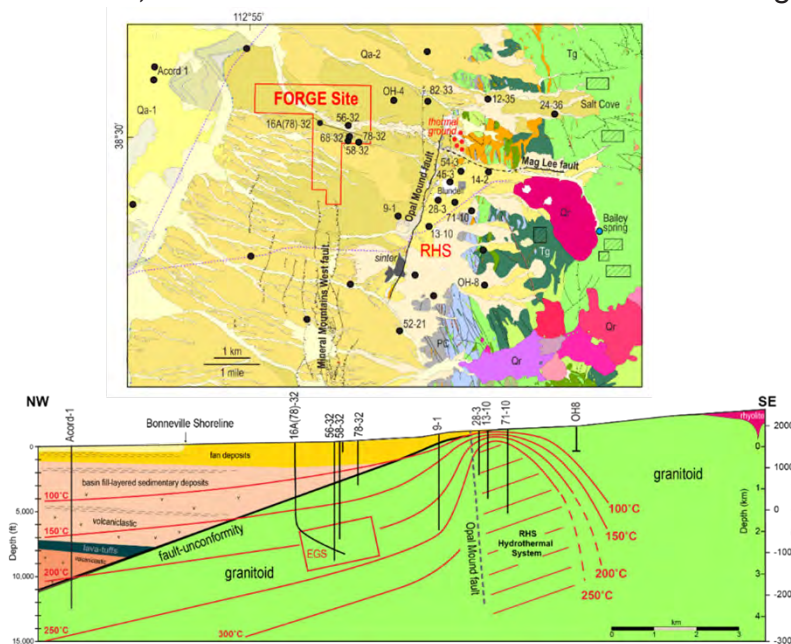


Figure 2. The geology of the area is dominated by Tertiary granite that forms the core of the Mineral Mountains shown in green. The red and purple rocks are rhyolites emplaced around 750,000 years ago. A still cooling magma body underlies the range and provides heat to the area. The Blundell Geothermal Power plant lies east of the Opal Mound Fault. The black dots are geothermal and gradient wells; those east of the Opal Mound Fault near the plant produce 250°C water. Notice the granitic basin fill contact dipping approximately 25° to the west. The basement top has been interpreted as the exhumed footwall of a rotated Basin & Range fault. No offset of the basement top has been observed at FORGE.

of a working fluid (water is the simplest) to extract heat as fluid moves down an injection well, through the fractures (imagine fins on a heat sink in your computer) picking up thermal energy, and flow to a power plant at the surface through a production well. The half-century of interest has been populated with EGS projects of significant scientific success, however they have been Pyrrhic victories from the perspective of commercial electricity production (Figure 1).

About a half-decade ago, the DOE recognized that advances in geo-engineering, particularly

regionally and the local risk of induced seismicity is considered low; and, 5) the environmental risks are low (there are no endangered species, there is no nearby human activity, and there is no potable water).

The FORGE concept builds on developments in directional drilling, hydraulic fracturing, and stage isolation -- with the added complexity of high temperature. The basic initial premise is to drill an inclined injection well (Figure 3), hydraulically fracture the toe of this well, and subsequently drill a production well to intersect the hydraulic

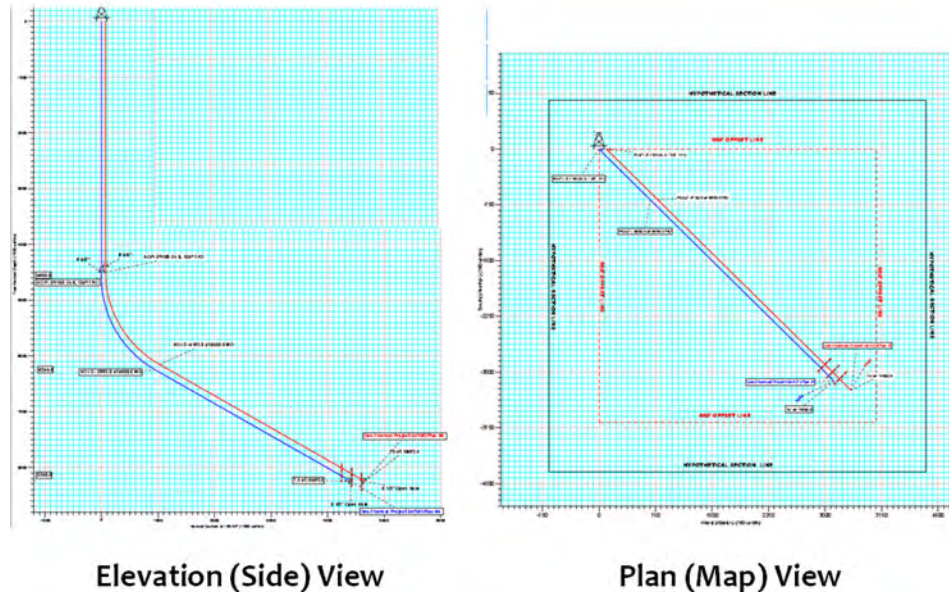


Figure 3. An archival sketch that shows an initially drilled injection well (16A(78)-32), three fractures near the toe as described in the text above, and a planned production well (16B(78)-32, shown in red. The actual trajectory of the injection well is 65° to the vertical at an azimuth of 105°.

direction drilling, overcame some of the weaknesses of earlier EGS forays. After a competitive selection process, the United States Department of Energy selected a site near Milford, Utah, to construct a field EGS laboratory to incubate, develop, and test techniques and tools for commercializing EGS. This Utah site is designated as FORGE -- Frontier Observatory for Research in Geothermal Energy. The Utah FORGE location met several important criteria: 1) temperatures were adequately hot to effectively test tools and techniques but not so hot to lead to exceptional expenditures for well construction (the static temperature recorded in one well at FORGE that is 9500 ft TVD was 235°C); 2) the rock is a low permeability granitoid (subtle mineralogic variations) as shown in Figure 2; 3) there is a conductive thermal regime with no evident connection to a hydrothermal system; 4) there is a four-decade history of seismic monitoring

fractures, as delineated by a network of deep geophones in monitoring wells, and a surface seismic network. Ideally, this will provide the basis for a heat exchange system. Recall that this is a field laboratory. Research contracts funded by the DOE will be used to exploit the unfractured portions of these wells to develop new treating and completion methods, new logging and thermal reservoir characterization methods, and techniques for ensuring thermal conformance along the lengths of multiply fractured wells.

The current status is that six wells have been drilled. This includes the initial well (58-32), two shallow wells (68-32 and 78A-32), and the first of the two inclined wells (16A(78)-32) as well as two deep monitoring wells (56-32 and 78B-32). Figure 4 is a drone view of the drilling pattern. The monitoring wells will

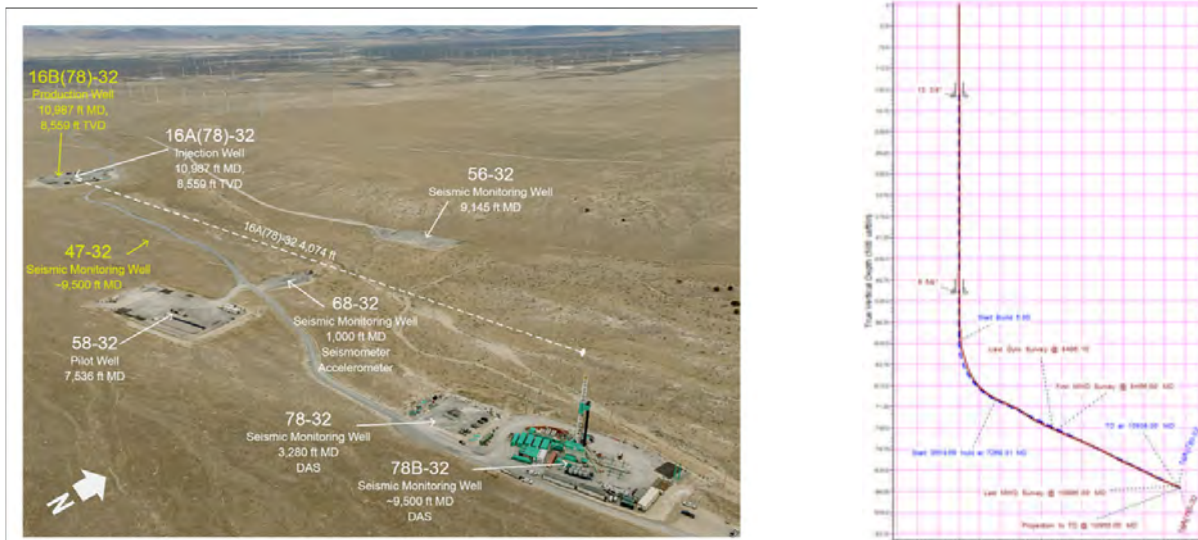


Figure 4. An aerial view looking to the NW shows the vertical wells and the inclined injection well (16A(78)-32, in the background) and a dotted line showing the projection of the inclined well at the surface. The plot at the right is a near-elevation view of the inclined well. Courtesy Utah FORGE

accommodate geophone strings to triangulate on microseismicity generated during hydraulic fracturing in the spring of 2022.

The drilling of the last three wells has been remarkably successful. Working with colleagues at a Texas A&M project engaged under a DOE contract to advise drilling operations, directional tool vendors and bit vendors, record drilling rates for hard, abrasive granites were established and progressively broken. This is evident in Figure 5, as polycrystalline diamond compact (PDC) technology was proven and refined. The reader is referred to Dupriest and Noynaert, in press [3] and Einkler and Swearingen, 2021[4].

Upcoming in the spring of 2022 will be three fracture stages at the toe of Well 16A(78)-32. These will be a slickwater stage ramped to rates of 50 bpm (if possible) treating a 200 ft long barefoot section of the well. This will be followed by two stages near the 7-inch casing shoe. These will be through single perforated clusters using either slickwater or a viscosified fluid at rates up to 35 bpm (depending on friction and near-wellbore losses). Each stage will be uniquely traced with an organic tracer. Microproppant will be pumped in the third (viscosified) stage. The superficial goal is to create distinct fractures that can be intersected by the drilling of Well 16B(78)-32.

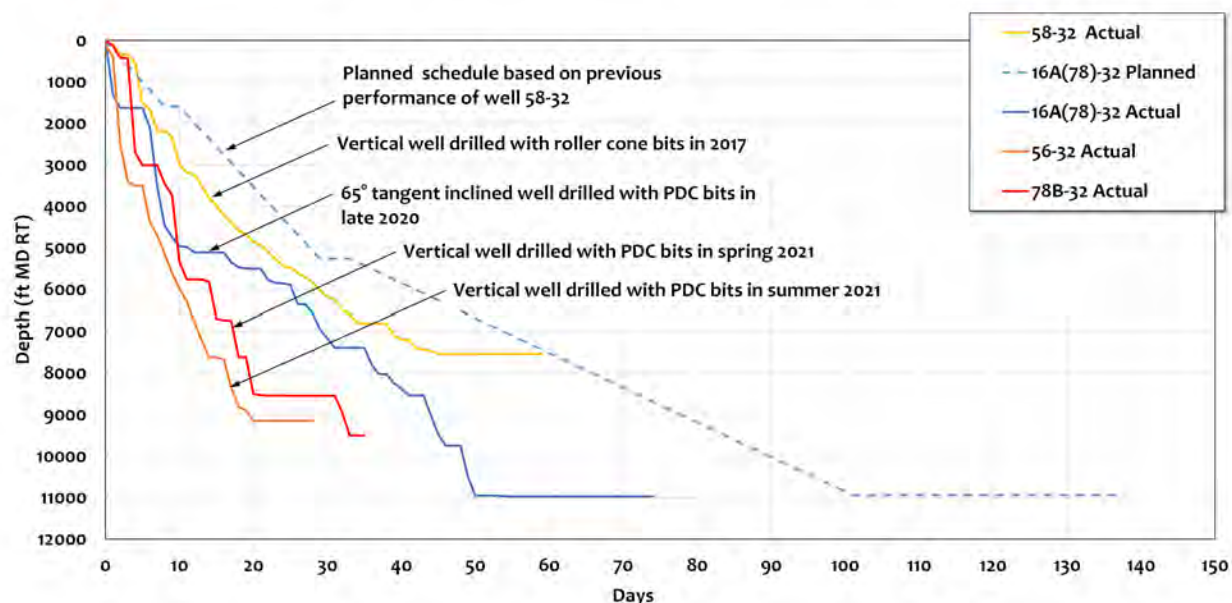


Figure 5. Progressive improvements in drilling rate of penetration and the time "on-bottom" for each bit run.

FORGE's research program can be summarized as follows.

- **Connectivity:** Establish that hydraulic fractures, with a limited stage to stage interaction, can interconnect two inclined wells. The first of these inclined wells has been successfully drilled, extensive logging and fracture analysis has been carried out, substantial numerical simulations have been done (refer to Damjanac et al., 2021, this issue[5]) and preliminary injection testing has been carried out (Xing et al., 2021[6]). Hydraulic fracturing is planned for the spring of 2022.
- **Conductivity:** Establish that hydraulic fractures do indeed connect discretely and explicitly, with a limited stage to stage interconnection, yet with adequate conductivity to minimize parasitic losses associated with pumping cold fluid down the injector. For example, remedial fracturing may be required from the injector, producer, or both.
- **Conformance:** Ensure that there is nominally equal injection and production from each discrete stage. This is an ongoing funded area within the FORGE program and elsewhere within the GTO portfolio (diverters).
- **Conversion:** Ultimately it needs to be determined if EGS makes sense from a perspective of delayed thermal depletion. Circulation testing will confirm this after the heat exchange system is built.

The project data in totality are publicly available at [GDR.OPENEI.ORG](https://gdr.openei.org) or <https://utahforge.com/>.

Funding for this work was provided by the U.S. DOE under grant DE-EE0007080 "Enhanced Geothermal System Concept Testing and Development at the Milford City, Utah FORGE Site." The authors thank the many stakeholders who are supporting this project, including Smithfield, Utah School and Institutional Trust Lands Administration, and Beaver County as well as the Utah Governor's Office of Energy Development and the Utah Congressional delegation.

Resource List

[1] Tester. J.W. et al. 2006. The Future of Geothermal Energy: Impact of Enhanced Geothermal Systems (EGS) on the United States in the 21st Century, Idaho National Laboratory, November.

[2] Breede, K., Dzebisashvili, K., Liu, X. et al. 2013 A Systematic Review of Enhanced (or Engineered) Geothermal Systems: Past, Present and Future, *Geotherm Energy* 1, 4 <https://doi.org/10.1186/2195-9706-1-4>

[3] This will be published in the proceedings of the 2022 Drilling Conference, Galveston TX, March 2022. Dupriest, F., Noynaert, S. 2022. Drilling Practices and Workflows for Geothermal Operations, SPE-208798-MS, 2022 IADC/SPE International Drilling Conference and Exhibition (in press)

[4] Winkler, D. and Swearingen, L. 2021. Summary of Drilling Activities: Well 16A(78)-32, Utah FORGE report, March.

[5] Damjanac et al. 2022. TBD, ARMA Letters, Winter Edition.

[6] Xing, P. Damjanac, B., Radakovic-Guzina, Z., Finnilla, A., Podgorney, R., Moore, J., and McLennan, J. 2021. Numerical Simulation of Hydraulic Fracturing Stimulation Enhanced Geothermal System Well at Utah FORGE Site, 55th US Rock Mechanics/Geomechanics Symposium, June 18.

Geothermal Plants in Latin America

Submitted by Paul Moya Rojas, Independent Consultant, Costa Rica

Since the first geothermal power plant, integrated to a grid in Latin America, started to operate in Pathé geothermal zone in 1959 -- located in central Mexico with a capacity of 3.5 MW [1] -- there has been an increasing use of geothermal as a source of power. This document provides an overview of the countries currently having geothermal plants in Latin America, with a summary provided in Table 1.

Caribbean Islands

Many of the Caribbean islands have already identified their geothermal fields, such as: Montserrat, St. Kitts and Nevis, Dominica, Saint Lucia, and Saint Vincent and the Grenadines. Guadeloupe (at Bouillante) is the island that has already a geothermal power plant in operation, with an installed capacity of 15 MW.

Mexico

Mexico was the first country that installed a geothermal plant in Latin America. The first geothermal power plant, which was integrated to a grid in Latin America, started to operate in Pathé geothermal zone in 1959, located in central Mexico with a capacity of 3.5 MW [1]. Currently, Mexico has developed 5 geothermal fields, with a total installed capacity of 1,002.8 MW.

Current plans are expected to increase the installed capacity in many of the geothermal fields in Mexico, at the following sites: 40 MW (in Cerro Prieto), 1.7 MW (in Las Tres Vírgenes), 10 MW (in Los Azufres) and 26.5 MW (in Los Humeros). The first unit installed in the Pathé geothermal zone (3.5 MW) as well as two units in Cerro Prieto (37.5 MW each) are currently inactive. [1]

The only current and foreseeable hurdle to development is, as usual, of economic nature. Due to the high upfront investments, the high risk in the early stages and the long time required to develop geothermal-electric projects, particularly of greenfield type, the timescale for new development is unpredictable. Geothermal electric projects from both the Federal Commission of Electricity and private developers must compete with solar and wind projects whose initial investments and risks are much lower, and their development times much shorter. And even if the levelized cost of generation is competitive for the mid- and longer term, investors (and bankers) tend to seek easier and less risky ways to develop energy sources, basically due to the baseload character of geothermal power plants. [1]

Central America

Geothermal energy in Central America has been studied and developed for decades. These countries were able to develop their geothermal projects, taking advantage of soft loans from U. S. and Japanese banks to the countries (sovereign guarantees) when these banks routinely lent money for geothermal projects [2]. Most recently, some Japanese banks are providing loans for these projects again, such as the Japan International Cooperation Agency (JICA) funding for future geothermal developments in Costa Rica (Las Pailas 2 (finished in 2019), Borinquen 1 (currently under development and expected to

be operational in 2027) and Borinquen 2), Bolivia (Sol de Mañana, Laguna Colorada) and perhaps in Ecuador (Chachimbiro) around 2-3 years from now.

• Guatemala

Today in Guatemala, there are two geothermal fields (Amatitlán and Zunil) with geothermal power plants generating electricity. The total installed capacity in Guatemala is 52 MW.

Between 1970 and 1990, there was strong support from the government for the exploration of geothermal resources of the country. This important support was lost once the government of Guatemala decided to privatize some of its institutions and/or allow private companies to participate in the development of geothermal resources. Companies such as Orzunil in 1999 and Ortitlán in 2007 have been in control of the development of geothermal resources in Guatemala. [2]

INDE will have to settle the social issues in the zone around the possible development of Zunil 2, as well as in the preparation of its personnel, to continue the development of the geothermal resources in the country. [2]

• El Salvador

The initial exploration studies in El Salvador were undertaken in 1958, with the first geothermal exploration well being drilled in 1968 in Ahuachapán. [3] The geothermal development in El Salvador was done by a public institution, the Hydroelectric Commission of Lempa River in El Salvador (CEL) that sought soft loans for exploration work and later was able to install most of the units in Ahuachapán and Berlin; these geothermal fields have a total installed capacity of 204.2 MW.

Even though there are many geothermal areas identified in El Salvador, only the geothermal areas called Chinameca, and San Vicente are planned to be developed soon with geothermal plants between 10 and 25 MW.

• Honduras

Geothermal exploration in Honduras began in the late 1970s, when Geonomics, Inc. began

preliminary investigations. These investigations pointed to the areas of Pavana and Choluteca as possible areas of geothermal interest. [4]

In 2013, Ormat signed a Build, Operate, and Transfer (BOT) contract for the Platanares Geothermal Plant with ELCOSA in Honduras, a private Honduran energy company. Geotérmica Platanares will sell its energy, mainly under a 30-year energy sale contract to ENEE. At the end of 2017, the Platanares geothermal power plant (35 MW) began its contribution to the electrical supply facilities in Honduras.

• **Nicaragua**

Nicaragua has also developed two geothermal fields: Momotombo and San Jacinto-Tizate. The Momotombo Geothermal Field was the first one to provide electricity to the grid. It was installed in two units of 35 MW and a binary plant of 7.5 MW, for a total of 77.5 MW. Unfortunately, only one of the units of 35 MW is still producing electricity to the grid (there is not enough steam to produce the other 35 MW). On the other hand, two units of 36 MW were installed in San Jacinto-Tizate, reaching an installed capacity of 72 MW. The current installed geothermal capacity in Nicaragua is now 107 MW.

Due to the devastating 1983 earthquake and the civil war, the government of Nicaragua could not continue the development of their geothermal fields and decided to turn to private developers. Therefore, concessions for the two producing fields (Momotombo and San Jacinto-Tizate), as well as concessions for the development of El Hoyo-Monte Galán, Managua-Chiltepe and Casita San Cristóbal were awarded. [2]

The government soon realized that the private sector was not developing the geothermal resources in Nicaragua as quickly as expected and began looking for options to mitigate drilling risk in the exploration phase, as well as attempting to obtain financial resources to carry out more studies which could provide more information to the private sector about the possibilities of development. Unfortunately for the government of Nicaragua, these actions have failed thus far to attract more private companies to invest in the Nicaraguan geothermal resources. [2]

• **Costa Rica**

In the early 1970s, Costa Rica satisfied its electricity needs using hydro and thermal energy sources (70% and 30%, respectively). The continuous rise in oil prices, especially during the 1973 crisis, motivated the authorities of the Costa Rican Institute of Electricity (ICE) to study the possibility of using alternative energy sources for generating electricity, including geothermal energy. [6]

Costa Rica has also developed two geothermal fields (Miravalles and Las Pailas geothermal power plants) and is currently developing another one called Borinquen-1, where a 55 MW plant is expected to be installed in 2027. The total installed capacity in Costa Rica is now 253 MW. Most of the geothermal sites are associated with volcanoes that are located within National Parks where current National Park Law does not allow any geothermal development. This constraint has already had negative consequences for Unit 1 at Las Pailas, such as lack of access to better permeability zones inside the National Park. This might have similar consequences for the next units ICE is planning to install at Las Pailas and Borinquen geothermal fields. [2]

South America

The countries near and parallel to the western coast along the Pacific Ocean are those with the possibility to develop geothermal resources. These countries are Argentina, Bolivia, Chile, Colombia, Ecuador, and Peru. [2] From these countries, Colombia has recently installed a small geothermal plant (0.1 MW), Chile has an operating geothermal plant at Cerro Pabellón (81 MW), and Bolivia is installing a geothermal binary plant (5 MW) at Sol de Mañana geothermal field, Laguna Colorada.

• **Colombia**

In a joint project by Parex, the National University of Colombia-Medellín and the national government through the Ministry of Mines and Energy, a 100-kW small-scale geothermal power generation unit was inaugurated in the Las Maracas field in Casanare, Colombia. This marks the first generation of geothermal energy in the country.

Table 1. Summary: Installed Geothermal Capacity in Latin America (MW)

Region	Country	Thermal Field	Installed Capacity (MW)
Caribbean Islands	Guadeloupe	Bouillante	15.0
Mexico		Cerro Prieto	570.0
		Las Tres Virgnes	10.0
		Domo San Pedro	35.0
		Los Azufres	267.5
		Los Humeros	119.8
		Total	1002.8
Central America	Guatemala	Zunil	28.0
		Amatitlan	24.0
		Total	52.0
	El Salvador	Ahuachapan	95.0
		Berlin	109.2
		Total	204.2
	Honduras	Pananares	35.0
	Nicaragua	Momotombo	35.0
			72.0
			107.0
	Costa Rica	Miravalles	163.0
		Las Pailas	90.0
		Total	253.0
South America	Colombia	Las Maracas	0.1
	Chile	Cerro Pabellon	81.0

Also, the possibility to develop a geothermal zone near the Nevado del Ruíz Volcano, among some other geothermal areas such the Tufiño-Chiles-Cerro Negro complex, still exists.

• Chile

Systematic exploration in the northernmost region of the country by the end of 1968 resulted in a project funded by the Chilean Development Corporation (CORFO) and the United Nations Development Program (UNDP). Geologic and geochemical reconnaissance studies of many hot-spring areas and detailed geological, geophysical, and geochemical surveys in selected areas such as Suriri, Puchuldiza and El Tatio geothermal areas were performed from 1968-1976. These were followed by drilling several exploratory wells and prefeasibility studies for power generation at El Tatio and Puchuldiza. [7]

In January 2000, a Geothermal Law was enacted providing the framework for the exploration and development of geothermal energy. It established exploration and exploitation concessions, which are granted by the Ministry of Mines. [8]

Chile also is producing geothermal energy in a field called Cerro Pabellón, where capacity to produce 81 MW is now installed.

Observations and Conclusions

In Latin America, México, and most of the countries from Central America have developed their geothermal resources. On the contrary, in the Caribbean Islands and South America the development of the geothermal resources has been very slow and limited, even though these regions have the possibility to develop many already identified geothermal fields.

Some of the reasons why there are not more geothermal developments in Latin America are: [2]

- In some countries the laws of National Parks prevent developments within their parks or protected areas; it may also be that consultation with their indigenous population is required, before starting any geothermal development.
- Lack of financing (large investments required during the initial stage of the geothermal development).

- Environmental and social impediments.
- Governments expect private companies to carry out the geothermal development of the country, because governments have no interest, funds, or personnel to develop geothermal fields.
- Lack of tax incentives and/or lack of the establishment of incentives or fiscal mechanisms.
- A reduction of legal and regulatory aspects is required.
- The possible energy generation does not seem to be enough to justify the investment by the government or private companies.
- Financial and technical obstacles.
- Lack of training of technical staff.
- Political situations of countries and the establishment of wrong policies for geothermal development.
- Need to develop infrastructure near geothermal fields (roads, camps, electricity, telephone, internet, water for drilling, etc.).
- There is no designated authority in charge of geothermal development, nor a source of guidance in the preparation of technical personnel in many geothermal disciplines.
- More detailed information is required to incentivize geothermal development for both the public and private sectors.
- Some public institutions, which had begun preliminary studies, were closed, or disintegrated by political decisions.
- Political decisions have prioritized hydropower and subsidized thermal energy (oil), which then delays geothermal development.
- The government expects the private sector to take the risk and develop geothermal resources, but at the same time, the private sector is hesitant to do so, given the available information.

The history of geothermal development in Latin America has demonstrated that government needs to play the most important position in the development of its resources. Governments interested in their geothermal development should invest in the critical early stage to reach the prefeasibility and feasibility stages of the project. The support of international lending agencies is also often crucial at this stage. Thereafter, the government can decide to do the development itself or to give it to a private company through a concession. For this last option, the regulatory framework must be clear and provide incentives that will encourage geothermal energy development. [2]

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A Review of Development and Utilization of Geothermal Energy Resources in China

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China is one of the earliest countries to start utilizing geothermal energy. Hot springs have been broadly developed since the 1950s and more than 160 hot spring sanatoriums were built in the 1960s. In the early 1970s, geothermal development in China entered a new phase, where multiple forms of geothermal energy utilization emerged, such as space heating, power generation, etc. Since the 21st century, the development and utilization of geothermal energy resources have expanded rapidly under the promotion of government policy. After decades of development, a primary pattern for geothermal energy utilization in China has been established: 1) space heating represented by Tianjin and Xiongan geothermal projects; 2) bathing and swimming represented by Southeast Coastal Region; 3) aquaculture and agricultural uses represented by the North China Plain; and 4) electric power generation represented by the Yangbajain in Tibet.

Geothermal Resource Distribution

Geothermal resources can be divided into shallow geothermal energy (<200m), hydrothermal geothermal energy (200~3000m), and hot dry rock (HDR, >3000m), based on the characteristics of the geological structure, reservoir temperature, and exploitation method. The assessment and investigation results of geothermal resources indicate that China is rich in geothermal resources; however, it is unevenly distributed due to tectonic movement, magmatic activity, and other factors.

Shallow geothermal energy resources are widely distributed throughout China with resources equivalent to 9.5 billion tons of standard coal. The annual exploitable yield of shallow geothermal energy resources in all 336 prefecture cities of China is equivalent to 700 million tons of standard coal, enough to heat (or

cool) an area of 32 billion m². The characteristics of the stratigraphic structure and hydrogeological conditions are the two main factors affecting the thermal conductivity of the geothermal reservoir. The suitable areas of shallow geothermal energy resources are mainly distributed in the central-east and northeast of China, among which North China Plain and Yangtze Plain are the most favorable locations for the utilization of shallow geothermal energy resources.

The total amount of hydrothermal geothermal resources in China is equivalent to 1.25 trillion tons of standard coal, and its annual recoverable resources are equivalent to 1.9 billion tons of standard coal. This makes up for 38.15% of the national energy consumption in 2020. The distribution of hydrothermal resources shows a distinctive regularity and regionality. According to tectonic genesis, geothermal resources can be divided into sedimentary basin geothermal resources and uplift mountain geothermal resources. Sedimentary basin geothermal resources are mainly distributed in meso-Cenozoic plain basins in eastern China where the geothermal energy is equivalent to 1.06 trillion tons of standard coal, showing a great potential for development.

China is rich in hot dry rock (HDR) geothermal resources, accounting for one-sixth of the world's total resources. The HDR geothermal within the

depth of 3.0~10.0 km is equivalent to 8.56×10^5 billion tons of standard coal in China. There are four types of HDR in China. First, high heat flow granite resources, which are mainly concentrated in the southeast coastal areas of China. Second, sedimentary basin HDR resources are primarily located in the lower part of cretaceous basins. Third, modern volcanic HDR resources, which are extensively distributed in Tengchong and Changbai Mountain regions. Fourth is the intense tectonic movement region, which is mainly distributed in the Qinghai-Tibet Plateau of China. Based on HDR energy evaluation and economic analysis conducted by China Geological Survey Bureau, several target areas for HDR exploration have been selected, such as Gonghe Basin, Guide Basin, Leiqiong area, Songliao Basin, Tibet, and eastern Hebei area.

Geothermal Utilization Status

- **Direct application**

China has abundant geothermal resources with great potential for development, however, geothermal utilization is still in the very early stages. The utilization of geothermal resources only accounted for 0.6% of the total energy consumption in 2020 in China, although great efforts have been made to promote the development and utilization of geothermal energy recently.

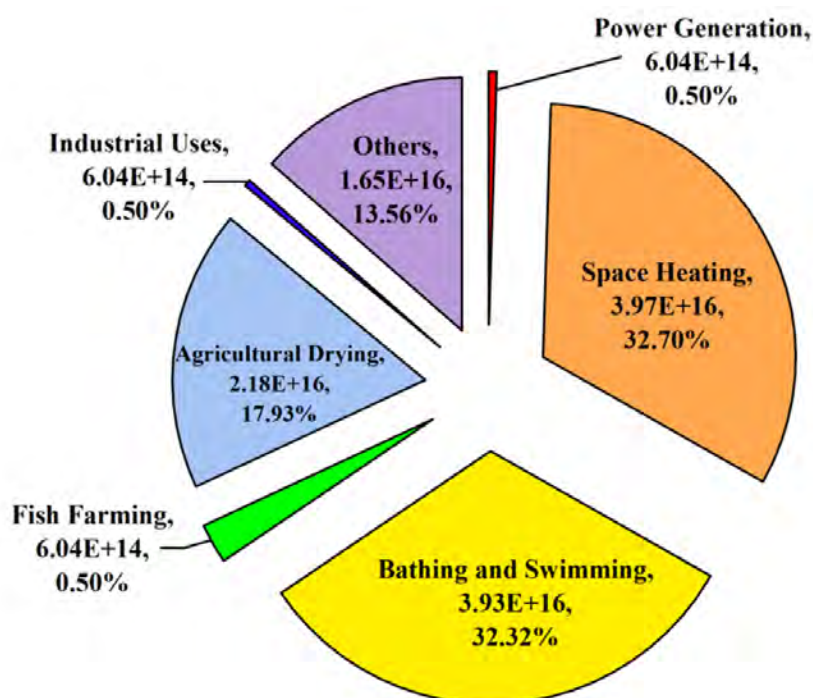


Figure 1. Geothermal utilization status in China (Zhang et al., 2020; Wei, 2018; He, 2020)

Direct use of geothermal energy is one of the oldest, most versatile and common forms of utilizing geothermal energy. In the past 10 years, China’s direct utilization of hydrothermal geothermal energy has grown at an average annual rate of 10%, ranking first in the world in recent years. The total installed thermal capacity for geothermal direct utilization was 40610 MWt in 2020, accounting for 38% of the world’s direct use of geothermal energy. Figure 1 shows the proportions of geothermal energy in different forms of utilization in China. Space heating and bathing uses account for the majority, reaching 65.02% of total use, followed by agricultural uses, accounting for 17.93%.

cooling. In 1990, the hydro-geothermal heating area was only 1.9 million m², but it increased to 580 million m² in 2020 at a compound annual growth rate of 28% since 2010 (Figure 2). Tianjin is the leading city in terms of the heating area by hydrothermal, which heated the area of 21 million m² last year, accounting for 6% of the city’s district heating area. Moreover, Xiongan New Area’s hydro-geothermal heating area is about 4.5 million m², which meets more than 95% of the county’s winter heating demand; this is referred to as the “Xiong county” pattern for geothermal energy utilization in China. In addition, to protect geothermal resources, the water after heating is reinjected; this is particularly significant to help realize the sustainable development of geothermal energy.

Table 1 Annual utilization geothermal direct use in China from 1995 to 2020 (Lund & Toth, 2020)

Year	1995	2000	2005	2010	2015	2020
Heat pump	0.8MWt	9.7MWt	631MWt	5210MWt	11781MWt	26450MWt
	7TJ/a	83TJ/a	6569TJ/a	29035TJ/a	100311TJ/a	246212TJ/a
Space heating	87MWt	248MWt	550MWt	1040MWt	2940MWt	7000MWt
	1.75M m ²	4.95M m ²	9.60M m ²	30.20M m ²	60.32M m ²	139M m ²
Direct utilization	1915MWt	2814MWt	3687MWt	8898MWt	17870MWt	40610MWt
	16981TJ/a	31403TJ/a	45373TJ/a	75348TJ/a	174352TJ/a	443492TJ/a

The growing awareness and popularity of ground-source (shallow geothermal) heat pumps have the most significant impact on the direct use of geothermal energy. In 2009, GHP accounted for 53.5% of the installed capacity and 51.9% of the annual energy use. Today, these numbers are 65.9% and 57.5% respectively. It is worth mentioning that China’s installed capacity of ground-source heat pumps reached 2.65 GW, ranking first in the world by the end of 2020, as shown in Table 1. In terms of the geothermal heated area in China, it exceeded 1.39 billion m² in 2020, with heat pumps making up 58% of the total heated area; this source account for a reduction of more than 62 million tons of carbon dioxide, equivalent to over 25 million tons of standard coal.

Middle-low temperature hydro-geothermal energy resources are another major source for heating and

• **Electricity Production**

Geothermal power generation is the fast-growing section in the utilization of geothermal energy. Use of geothermal energy to generate electricity in China began in the 1970s. Seven middle-low temperature geothermal power plants were built with a total installed capacity of 1550 kW, including the world’s lowest temperature geothermal power station in Yichun County, Jiangxi province. In terms of high-temperature geothermal power plants, the Yangbajain geothermal power generation test unit in Tibet was installed successfully in 1977. This enabled China to became the eighth country in the world to master high-temperature geothermal power generation technology. By 1991, the Yangbajain geothermal power plant had an installed capacity of 24.18 MWe, generating about 100 million kWh of electricity annually and accounting for

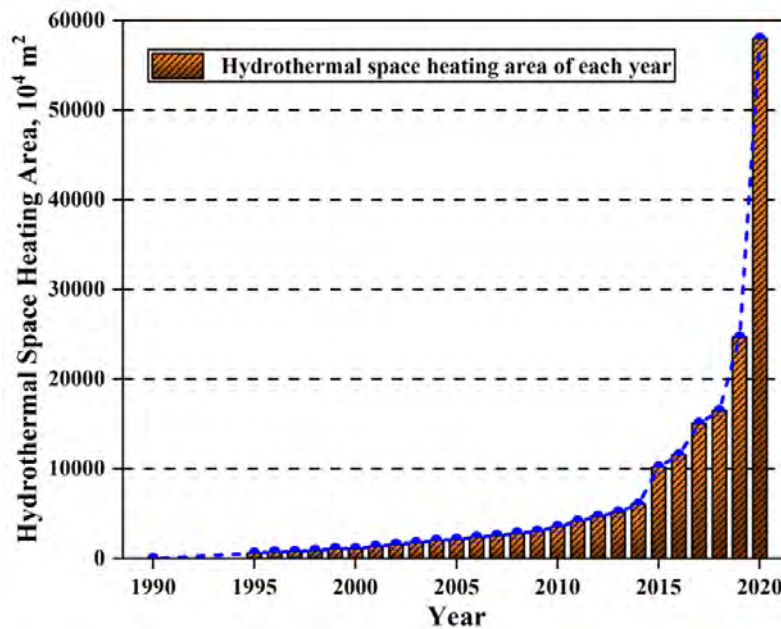


Figure 2. Hydrothermal geothermal heating area in China from 1990 to 2020 (Hou et al., 2018; He, 2020)

41% of Lhasa's power supply. By 2015, the installed geothermal power capacity reached 27.78 MWe in China, only accounting for 0.2% of the world's total installed capacity. However, it has seen fairly rapid geothermal development in the past few years, with a number of geothermal

field (not far from Yangbajain), which is currently the largest single-unit geothermal power plant in China and the highest geothermal power plant in the world, at an altitude of 4650m. By the end of 2021, the total installed capacity of geothermal power in China is estimated at 45.46 MW, an

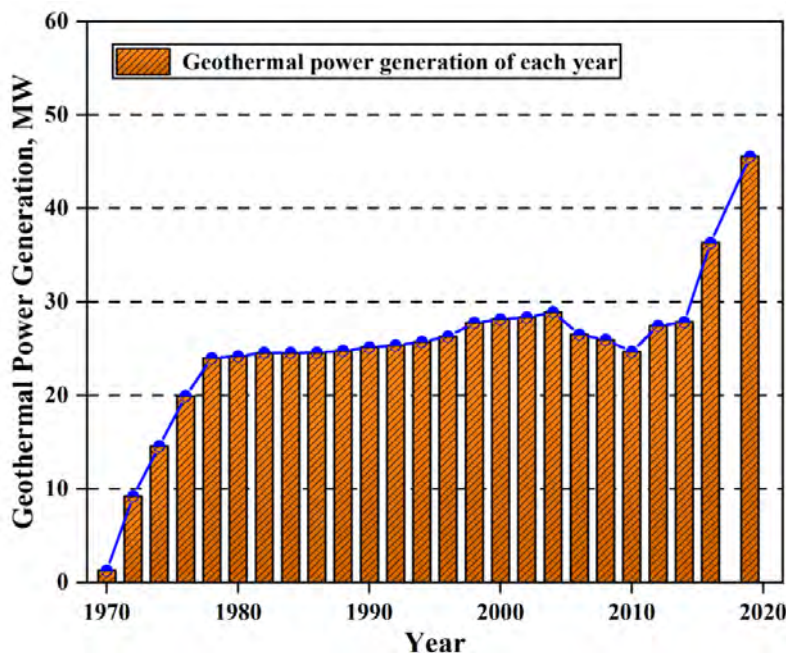


Figure 3. Installed capacity of geothermal power generation in China from 1970 to 2020 (Zhu et al., 2015; He, 2020)

power plants under construction, including high-temperature geothermal power plants in Tibet and western Sichuan.

On 9 October, 2018, the Yangyi geothermal power station (16 MW power generation project) obtained the grid connection license from the State Grid Tibet company. 16 MW full flow systems were installed in the Yangyi geothermal

increase of 68% since 2015 (Figure 3).

• Hot Dry Rock Geothermal

The utilization of hot dry rock geothermal resources in China is at a very early stage and has not been economically developed. In 2012, the China Geological Survey launched the "National hot dry rock resource evaluation and target area

investigation” project. The reserves of dry hot rock resources in China were investigated, and four types of target areas of dry hot rock in China were proposed. In the same year, the Ministry of Science and Technology set up the “863 Program” project -- “Key technology research on thermal energy development and comprehensive utilization of hot dry rock”, which started the fundamental research of HDR development. In 2017, the GR1 well in Gonghe Basin was drilled to a depth of 3705 meters where rock temperature reached 236°C. This was the first time to drill a HDR geothermal reservoir in China and seven exploration wells were drilled in Gonghe Basin, four of which encountered HDR reservoir, as shown in Figure 4. Meanwhile, the geological structure and spatial distribution of some key target areas in Gonghe County were further explored and studied. The results indicated that the area of HDR attained by exploration wells in Qiabqia is about 246.9 km². According to the simulation results, 18 target zones of HDR were outlined in Gonghe basin, with a total area of 3092 km².

on 30 June, 2019, HDR with a temperature of 150°C was drilled at a depth of 3965 meters in Tangshan, which is the shallowest HDR reservoir founded in Beijing-Tianjin-Hebei region. These findings created a breakthrough in HDR exploration in central and eastern China. The exploration results showed that the prospective reserves of HDR resources are equivalent to about 2.8 billion tons of standard coal.

Fundamental Research and Future Works

Benefiting from the requirement for energy conservation in buildings and reduction of CO₂ emissions in China, more and more scientific research institutions have started to focus on geothermal energy development. Some progress has been made on key issues, such as exploration, drilling, hydraulic fracturing, heat transfer, and water reinjection.

In terms of geothermal geology, a series of research studies have been going on with

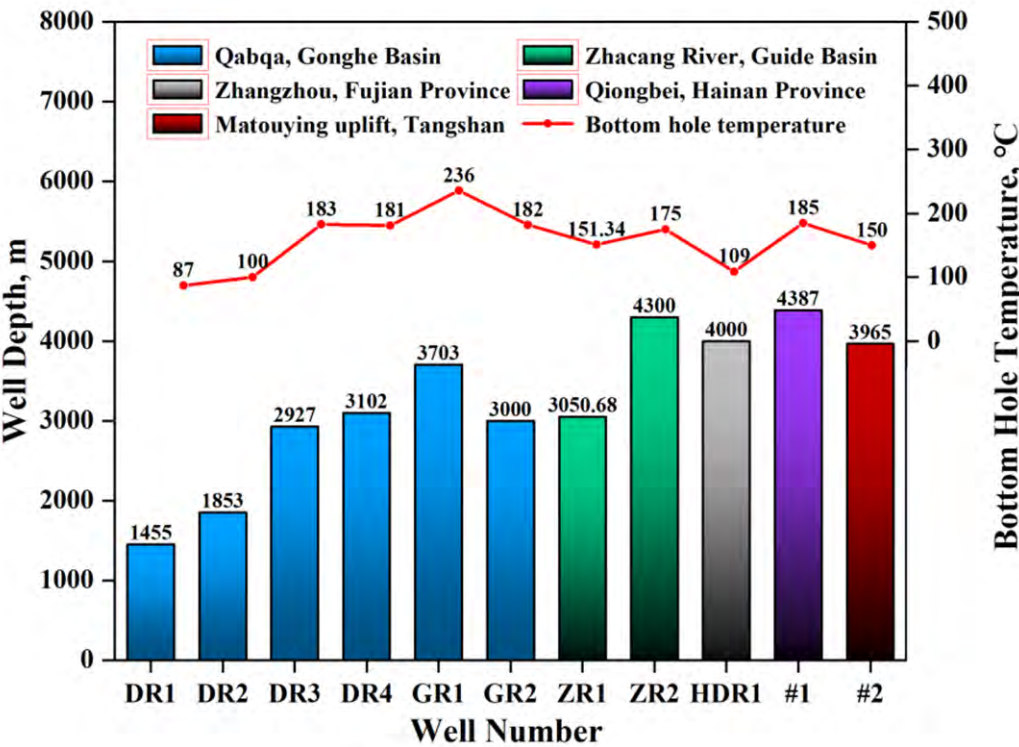


Figure 4. HDR geothermal wells in China (Zhang et al., 2019)

At present, hydraulic fracturing has been carried out in Gonghe basin and the power generator was installed, however, the results of the test have not been publicly reported. Meanwhile, in March 2018, another geothermal well encountered a HDR reservoir of more than 185° at a depth of 4387 meters in Qiongbei, Hainan. Additionally,

respect to the earth heat flow field, geothermal genesis, and evaluation of geothermal energy resources, to provide theoretical guidance for the exploration and development of geothermal energy resources. In recent years, great progress has been made in geological and geophysical characterization

of geothermal resources distribution and three-dimensional seismic geological structure modeling, which has significantly improved the accuracy and efficiency of target HDR geothermal resources selection.

With respect to drilling geothermal wells, high efficiency and low cost are always the priority for developing geothermal resources. Since the late 1990s, drilling and completion technologies for the oil industry have begun to apply to geothermal plant construction, which has greatly improved drilling efficiency and shortened well construction time. Several high-temperature geothermal wells have been successfully drilled with temperatures above 300°C in Yangbajing, Tibet, Kenya, and Turkey. In 2018, high-temperature water-based mud was successfully developed in China, reaching a temperature of 242°C. However, there are still some difficulties with drilling HDR reservoirs, such as low ROP, long construction time, and high cost. For example, it took 185 days to drill the GH01 well in HDR in the Gonghe basin, which consumed more than 50 drilling bits. In the future, we expect to break through the key technical bottleneck of HDR drilling through a series of research studies about high-temperature resistance drilling equipment, rock breaking mechanism of special-shaped PDC bits, and axial torsional coupling drilling technology.

As for HDR formation stimulation, although China has not established EGS yet, a lot of research has been going on through lab experiments and numerical simulations. It was observed that the breakdown pressure of HDR is relatively high, and poor connections randomly happened between injection wells and production wells according to simulation results of EGS projects worldwide. The next step is to focus more on exploring “soft stimulation” that could reduce seismic risk and relate to complex fracture networks, including cyclic fracturing (fatigue fracturing), CO₂ fracturing, liquid nitrogen fracturing, and ultra-short radial well fracturing. These advances will help break through the key technologies of hot dry rock reservoir reconstruction. (Huang et al., 2020).

Some progress has been made in geothermal water reinjection. One of the main reasons for limiting the development of sandstone hydrothermal reservoirs is its low reinjection rate. China University of Petroleum (Beijing) collaborated

with Sinopec in a proposed series of solutions such as “heat extraction without water intaking” and “balanced injection and production” to prevent and remove plugging, which has been successfully applied to 65 geothermal projects with a reinjection rate of over 90%. The next step is to carry out research on reinjection blockage mechanisms, to optimize the layout of the production wells and injection wells, and to explore new low-cost and high-efficiency reinjection methods such as drilling radial wells.

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Modeling of EGS Reservoir Stimulation at Utah FORGE Site

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Introduction

Utah FORGE is a U.S. Department of Energy funded project whose purpose is developing and testing techniques for creating, sustaining, and monitoring Enhanced Geothermal System (EGS) reservoirs (Moore et al., 2019). From October 2020 to January 2021, the injection well, 16A(78)-32 (see Figure 1), was drilled, and injection and flowback testing was carried out. A vertically offset production well is planned for 2023. Both wells will be highly deviated with bottom-hole temperatures near 230°C. Multi-stage hydraulic fracturing stimulation is expected to be the most efficient and effective method for creating the fracture network that will form the reservoir between the injection and production wells. Hydraulic stimulation will be carried in three zones near the toe of Well 16A(78)-32 before drilling the production well. Two of the stimulated zones will be in the cased portion of the well, the third in the openhole section at the toe.

An extensive numerical study incorporating uncertainties in the in-situ conditions was performed to simulate the effects of different stimulation strategies. Fracture propagation, permeability enhancement, and induced seismicity were considered in this study. These simulations were conducted using a lattice-based code, XSite™, which simulates fully coupled hydro-mechanical processes (Damjanac et al., 2020). In this study, the objective was to investigate the reservoir stimulation of Well 16A(78)-32 with explicit representation of a discrete fracture network (DFN). The DFN was developed using geophysical logs from Well 16A(78)-32,

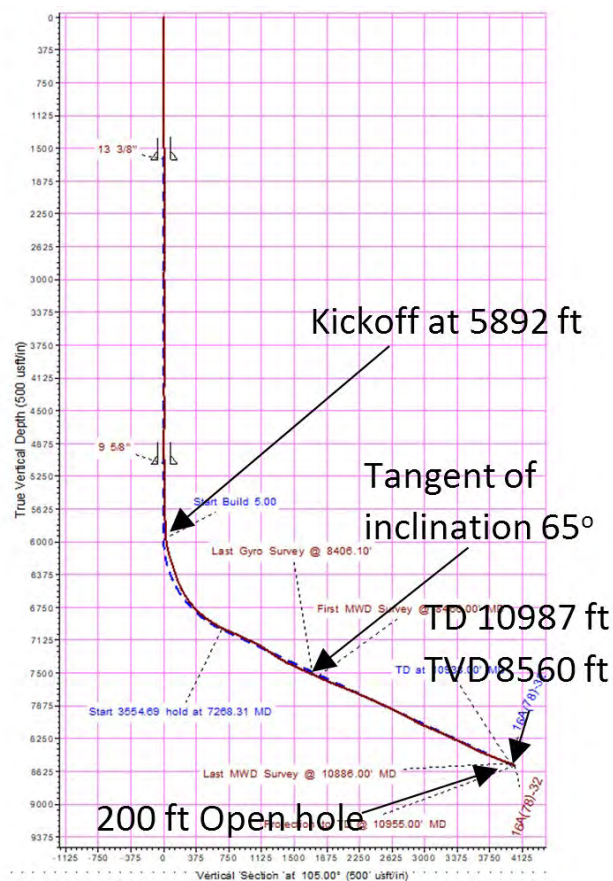


Figure 1. Trajectory of the injection well 16A(78)-32

previously drilled exploration wells, and fracture orientations and distributions exposed in nearby granitic outcrops representative of the reservoir rocks beneath the Utah FORGE site.

Overview of Injection Well 16A(78)-32

Drilling of the highly deviated injection well, 16A(78)-32, was completed in January 2021. The trajectory of Well 16A(78)-32 is shown in Figure 1.

The well was kicked off from the vertical at 5,892 ft measured depth (MD) and deviated at 5°/100 ft until it reached an angle of 65° to the vertical. The production casing shoe was set at 10,787 ft MD, and there is a 200 ft openhole section below the shoe. The MD of the well is 10,987 ft, and the true vertical depth (TVD) at the toe is 8,560 ft. The well recorded a temperature at total depth of 446 °F (230 °C). The horizontal offset is 4,074 ft.

Simulations of Hydraulic Stimulation from Well 16A(78)-32

Various simulations of the treatments at the

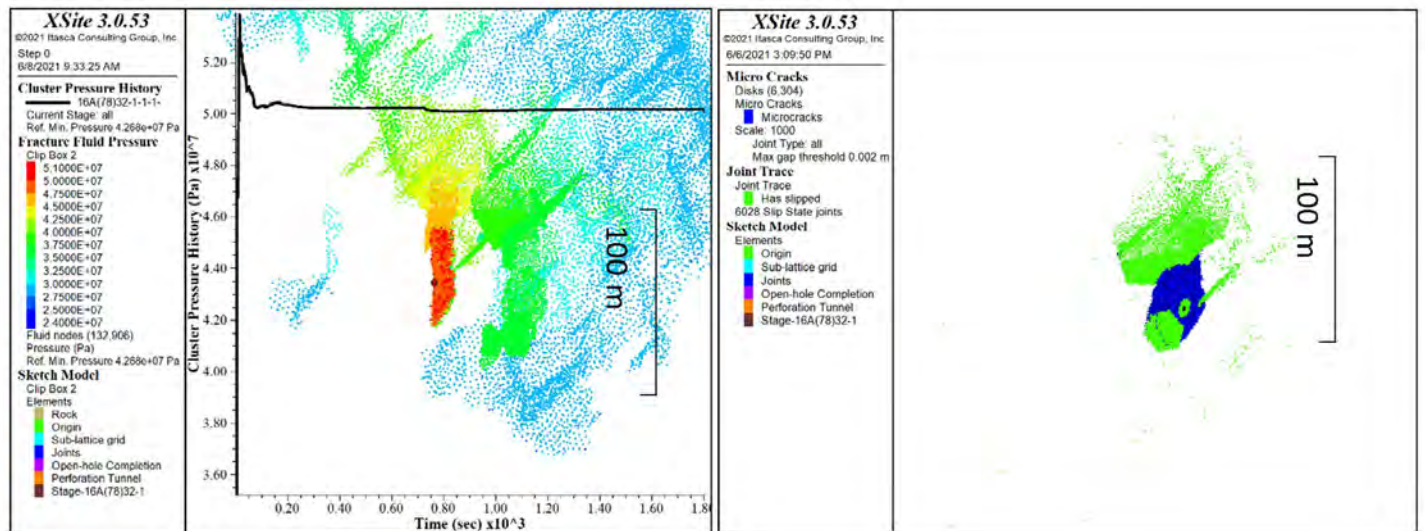


Figure 2. Simulation results of the base model after injection of fluid for 30 minutes at 20 bpm, no dilation of DFN. Left: Fluid pressure contours. Right: Newly created hydraulic fracture (blue) and natural fractures that have slipped (green).

toe of Well 16A(78)-32 were conducted. The numerical model was calibrated by pressure history matching of injection data from a DFIT at the toe of Well 16A(78)-32 (Xing et al., 2021). The effects of uncertainties related to DFN properties, including stochastic realizations of geometry, dilatancy, strength and permeability were investigated. Different operational parameters, such as pumping rate, pumping time, fluid viscosity, and fluid type were also studied. The simulations were carried out using the High Performance Computing resources at the Idaho

National Laboratory and required nearly 85 million CPU hours to complete.

Three indices were considered to characterize the extent of the stimulated volume: 1) induced hydraulic apertures greater than 0.2 mm; 2) open fractures (zero effective stress); and 3) slipping of existing fractures included in the DFN. Indices 1 and 2 would indicate connectivity by hydraulic fractures and/or connected fluid pathways within the DFN between the injection and production wells. Index 3 indicates the extent of hydro-shearing or irreversible permeability change.

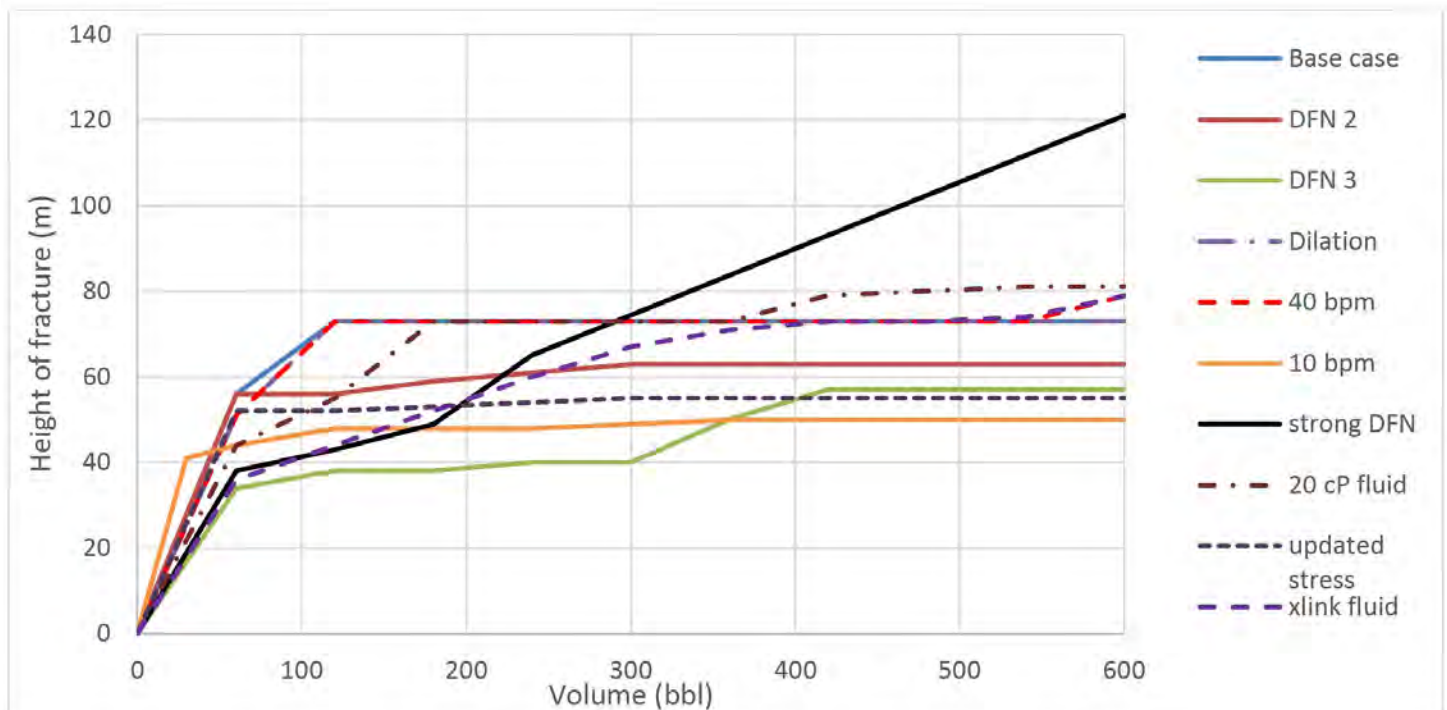


Figure 3. Comparison of fracture height for simulated cases. DFN1, DFN2, and DFN3 are three realizations of statistically the same DFN. All cases except DFN2 and DFN3 use DFN1 realization.

In the base model, slickwater is injected at 20 bpm for 30 minutes. The DFN is assumed to be permeable and frictional (with zero cohesion and zero tensile strength). The simulation results of the base model (using DFN 1) are illustrated in Figure 2. The response of the reservoir to injection in this case was dominated by fluid dissipation into the DFN and opening or slipping of the pre-existing fractures. The extent of the stimulated reservoir volume (as defined by the pre-existing or hydraulic fractures having hydraulic apertures greater than 0.2 mm post-stimulation, but not necessarily open) is 235 m above the injection point. The height of slipping fractures above the injection point is 93 m while the height of open fractures is only 78 m.

Figure 3 shows the comparison of open fracture heights for the simulated cases. For the cases with a strong (10 MPa cohesion) and in-situ impermeable DFN, the fracture heights are greater than for other cases, and there is very little fluid leakoff into the DFN. Higher fluid viscosity (20 cp fluid or xlink fluid) also promotes hydraulic fracture propagation. The case with a lower pumping rate (10 bpm) manifests the smallest open fracture height.

Increasing the pumping rate (from 10 bpm to 20 bpm to 40 bpm) resulted in a larger area of open and slipping fractures. For the case with a strong and impermeable DFN, the area of slipping fractures is negligible, but the area of open fractures is larger. Increasing fluid viscosity from 2 cP to 20 cP resulted in a higher injection pressure and, hence, a larger area of slipping and open fractures.

Conclusions

Numerical simulations of hydraulic stimulation in Well 16A(78)-32 have been conducted. The models explicitly represent the DFN constructed from image logging and deep acoustic log interpretations from this and offset wells. The simulations reflect the current interpretation of in-situ conditions, including geometry and hydro-mechanical properties of the DFN.

The modeling results indicate that in-situ strength and permeability of the DFN are the most important factors affecting reservoir response to stimulation by fluid injection. In the case of a permeable, frictional DFN, the reservoir response

is dominated by the DFN, and reservoir stimulation is a combination of natural fracture opening and slipping. If the DFN is impermeable and has significant cohesive strength, the injection mainly results in propagation of hydraulic fractures.

Acknowledgement

Funding for this work was provided by the U.S. DOE under grant DE-EE0007080 “Enhanced Geothermal System Concept Testing and Development at the Milford City, Utah FORGE Site.” We thank the many stakeholders who are supporting this project, including Smithfield, Utah School and Institutional Trust Lands Administration, and Beaver County, as well as the Utah Governor’s Office of Energy Development. This research made use of the resources of the High Performance Computing Center at Idaho National Laboratory, which is supported by the Office of Nuclear Energy of the U.S. Department of Energy and the Nuclear Science User Facilities under Contract No. DE-AC07-05ID14517.

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Conductive Heat Mining

Submitted by Ali Ghavidel, Robert Gracie, and Maurice B Dusseault; University of Waterloo, Waterloo, Ontario, Canada

Summary

We analyze heat extraction through purely conductive heat flux to a single, long borehole with a circulating fluid. In realistic scenarios, a sharp exit temperature drop occurs within a few months to several years, depending on flow rate and length, but less dependent on borehole radius and ΔT . Later, exit temperatures flatten to a slowly declining value for many years.

Discussion

Geothermal heat could be an alternative source of sustainable and carbon-free energy, partially displacing fossil fuels. Geothermal sources can produce electricity and heat, and can be especially valuable in cold regions such as Canada and northern US states.

Geothermal energy may be variously defined. In one definition, a geothermal source must carry three elements to become a commercial source: a high-temperature rock mass at a drillable depth (<2-3 km), a sufficiently porous and permeable rock mass, and availability of sufficient volumes of hot fluid - steam or hot water. These conventional geothermal resources are locally distributed; however, Hot Dry Rocks (HDRs) are present everywhere at depth, comprising a huge potential energy source (Edwards et al.,

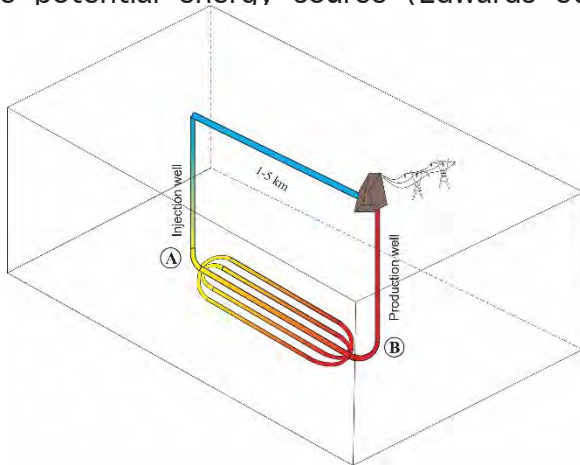


Figure 1. CLGS with multiple horizontal wells (Ghavidel et al., 2020).

1982), but deep and without natural fluids and flow paths (Olasolo et al., 2016).

New heat extraction concepts from HDRs have emerged: (1) Enhanced Geothermal Systems (EGS), where rock mass properties are enhanced by hydraulic stimulation (hydrofracturing or hydroshearing) to improve heat extraction; (2) Open Loop Geothermal Systems (OLGS), where heat extraction is based on closed-end wells with injection and production pathways in the same well (Wang et al., 2020; Cui et al., 2017; Wang et al., 2019); and (3) Closed Loop Geothermal Systems (CLGS), with the well doublet and relatively long horizontal wells (1-4

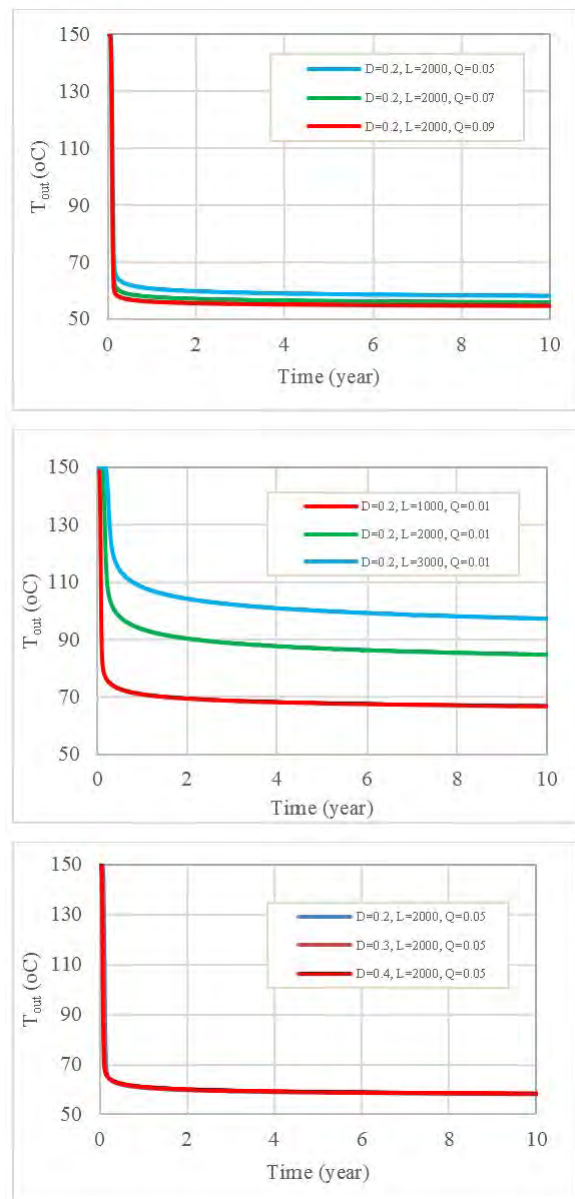


Figure 2. T_{out} for different single well CLGS flow rates (m^3/s), lengths and diameters (m).

km) (Schulz, 2008). CLGS is being tested at full-scale, in Canada (2022). Wellbores must be long enough to allow circulating fluids to be heated to an appropriate temperature. CLGS is isolated from the environment and has the advantage of significantly reducing risks of green-house gas emissions, seismicity, water loss, and aquifer contamination.

We analyze heat extraction from a CLGS doublet connecting five long horizontal wells (Figure 1). Since HDRs have low permeability, only conductive heat transfer is possible in the rock, and advection-diffusion dominates the heat transfer from the rock mass to the fluid in the horizontal well.

For analysis, the reservoir temperature at 2 km and the injection water temperature are assumed to be 150°C and 50°C, respectively.

The water temperature increases as it passes through the wells; this also cools the rock near the well. Heat flux from the higher-T surrounding rock via conductive heat transfer is far slower than the heat mining rate. Thus, the temperature around the well declines quickly, and the heat extraction rate drops. We note that the contribution of the conductive heat transfer mechanism within the well is trivial due to the fluid's velocity.

The outlet fluid temperature (T_{out}) over time is the most important metric for economic viability assessment. The outlet fluid rate must sustain power generation at the surface, typically using a Rankine cycle engine. We analyzed T_{out} with time for a CLGS well to look at electricity generation potential using an Organic Rankine Cycle (ORC) at surface.

T_{out} shows a rapid decline during the first few months (~1-6 months), depending on flow rate and well length, but far less dependent on borehole radius. Then, T_{out} flattens to a slowly declining value for many years (Figure 2). Since the outlet fluid at T_{out} feeds the ORC, the outlet electrical power follows the same pattern of the outlet fluid in the long term if the ambient temperature is assumed constant, i.e., a rapid decline in the first few months, and a flat level for a long time.

A single well cannot produce sufficient electricity for commercial viability (Ghavidel et al., 2022). In a multi-well scenario, additional wells are periodically brought on-line and fluid movement

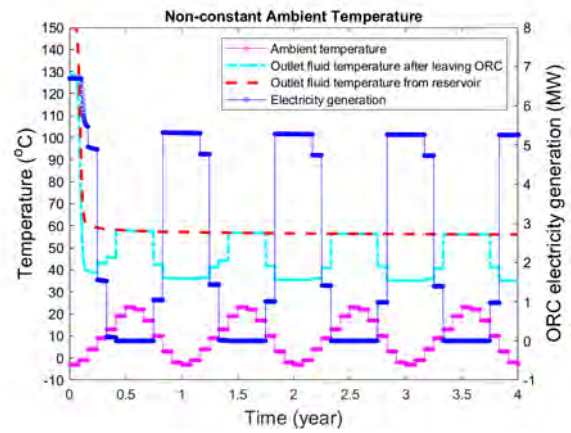


Figure 3. The outlet fluid temperature and produced electrical power from an ORC engine, varying over a year due to non-constant ambient temperature.

management used to sustain an elevated T_{out} so the ORC may function efficiently. CLGS with five horizontal wells ($L = 2$ km, $D = 20$ cm, $Q = 4$ m³/min/well) is evaluated for electrical power generation (Figure 3). If the ambient temperature is assumed to be non-constant over time (as in Canada), the outlet power fluctuates. In this case, in the first few months, the output power is mainly affected by the fluid temperature (falling over time). Thereafter, power is mainly dominated by the ambient temperature. Power during cold months (winter) is higher than hot months (summer), highlighting the impacts of a temperature difference between the ambient and inlet fluid on electrical power generation.

Figure 3 shows how electricity generation varies with ambient temperature over years. The horizontal axis shows monthly average ambient temperature starting January.

Lower electrical power generation during hot seasons means the condenser works at a higher pressure, lowering ORC efficiency. In winter, the condenser works at the lowest design pressure, so the ORC produces the highest power output. This leads to better performance when needed - during winter.

Geothermal projects can also provide direct heat. For the system in Figure 3, the fluid temperature after leaving the ORC heat exchangers is still high: 40°C to 60°C (when electricity generation is zero). Waste heat from ORC systems is valuable in cold regions (e.g., northern US States and Canada), especially where fuel cost or electricity delivery in remote areas is high (Elsaraf et al., 2021). For example, electricity may be used for home heating, but low-grade

heat from the generation process has high value if it can displace power or expensive fuel. Such co-generation improves economic outcomes.

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Thermo-poroelastic Effects in Geothermal Reservoir Stimulation

Submitted by A. Ghassemi, Reservoir Geomechanics & Seismicity Research Group, Mewbourne School of Petroleum & Geological Engineering, The University of Oklahoma.

When rocks are heated/cooled, the bulk solid and pore fluid tends to undergo expansion/contraction. The volumetric changes can cause significant pore fluid pressures and rock stresses depending on the degree of containment and the thermal and hydraulic properties of the fluid as well as the solid. The net effect is a coupling of thermal and poromechanical processes when developing a geothermal reservoir. Thermo-poromechanical processes play a key role in geothermal and petroleum reservoir development including induced seismicity, wellbore stability, hydraulic fracturing, and stimulation monitoring technologies. This paper highlights the significant role of coupled processes in the context of a few problems of interest in reservoir development with emphasis on enhanced geothermal systems and superhot rock resources.

Fracture initiation from a wellbore

In hydraulic fracturing, the fluid-rock mechanics coupling evolves rapidly (on the scale of minutes, hours to possibly a few days) compared to the thermal processes, thus the thermal effects may not have a large influence on the fluid-mechanical processes during hydraulic fracture propagation. However, for fracture initiation at the wellbore, and during a long-term injection phase (time scale of months to years), the thermo-mechanical coupling can no longer be neglected. In a geothermal reservoir the fracturing of the borehole due to thermally induced stress is often considered a potential mechanism for improving reservoir stimulation, particularly in superhot rocks. The problem is also of interest to the closed-loop concept of geothermal heat extraction.

The problem of crack growth from a pressurized borehole has been studied in the past (Mogilevskaya et al., 2000) and the conditions for initiation of thermal fractures from a cooled borehole has been numerically simulated (Dobroskok and Ghassemi, 2005; Ghassemi and Zhang, 2004). Laboratory investigation of pressurized borehole

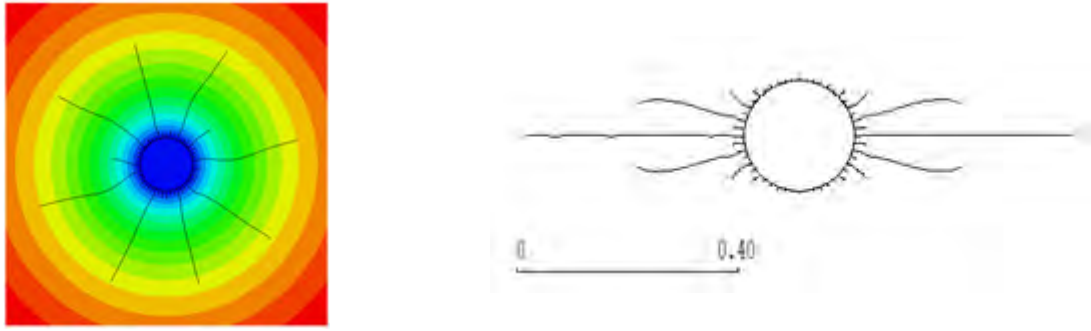


Figure 1. Typical crack patterns for isotropic (a) and anisotropic (b) in-situ stress field. (a) $S_h = S_H = 30$ MPa, (b) $S_h = 20$, $S_H = 30$ MPa; $K_{Ic} = 1$ MPa m^{1/2}. $E = 37.5$ GPa, $\nu = 0.25$; 200°C cooling (Tarasovs and Ghassemi, 2012).

cracking has also been performed (Schatz et al. 1987). A detailed analysis of the propagation of a system of radial cracks from a borehole has been presented (Tarasovs and Ghassemi, 2012) with emphasis on illustration of the dependence of multiple crack interactions and crack length on thermo-mechanics. Some highlights of the latter study are reviewed below.

character of the thermally induced stresses. The circumferential stress due to cooling is tensile at the borehole wall, and then it decreases and becomes compressive some distance away from borehole. On the other hand, the radial thermal stress is always tensile (except at the borehole wall, where $\sigma_r = 0$) and has a maximum some distance away from borehole.

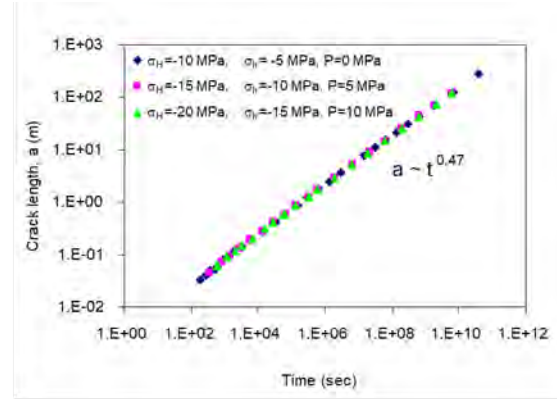
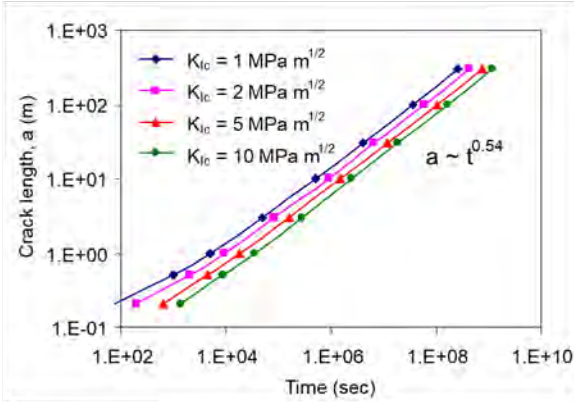


Figure 2. (a) Crack length dependence on the fracture toughness of rock in the absence of in-situ stresses; (b) crack length for simultaneous action of in-situ stress and internal pressure.

First, consider the isothermal problem of multiple micro-cracks emanating from a wellbore. Different number and length of initial cracks are used (three different initial configurations with 12, 24 and 48 initial small cracks; see Figure 1.). The initial crack lengths are 0.5, 1, and 3 cm and they are equally spaced, but the lengths are slightly different ($\pm$ few percent). The rock is subjected to in-situ stresses with no wellbore pressure is applied to isolate the cooling effect. Numerical results of a typical propagation pattern for a low and high stress anisotropy cases are shown in Figure 2.

Some cracks tend to stop at a specific moment in time and others redistribute themselves evenly in space around the wellbore. Numerical results show that the direction of crack growth may become unstable for some combination of parameters, and cracks may turn from radial to circumferential direction. This behavior can be attributed to the

For a single crack at the borehole wall in the direction of the S_H , numerical results show that for relatively long circulation (cooling) times, the crack length is a power function of time $a \sim t^n$ where the exponent n depends on the stress and can be found numerically. Figure 2a shows the crack length of the thermally driven cracks in the absence of a compressive in-situ stresses for different values of the rock fracture toughness. As can be seen, the crack length depends on the fracture toughness, however, for relatively long cooling times the curves are well described by the power law function with exponent equal 0.54 for all values of fracture toughness. Figure 2b shows the results of calculations with three different values of internal pressure and in-situ stress, in addition to thermal stress. The values of the in-situ stresses were changed, so that the sum of the in-situ stress and the pressure is constant in each case. The crack lengths and paths in all

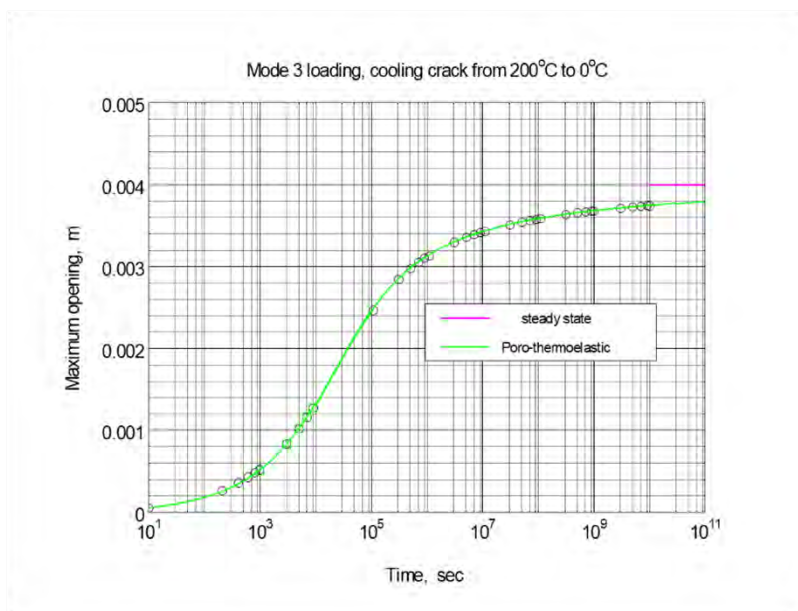


Figure 3. Crack aperture evolution with time under thermal loading.

three cases are practically identical.

Overall, numerical results show that for sufficiently long cracks, the length is a power function of time. The power law exponent depends only on the ratio of the in-situ stress acting perpendicular

influence on the crack length (see Tarasovs and Ghassemi 2012, a&b for more details). The foregoing analysis shows the potential of utilizing thermal stresses to lower the breakdown pressure and enhance stimulation potential for superhot rock resources.

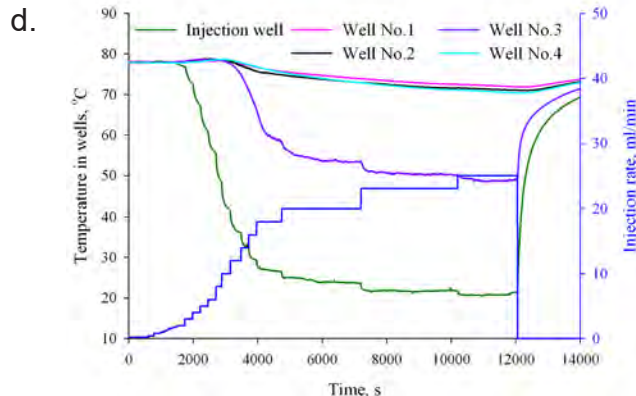
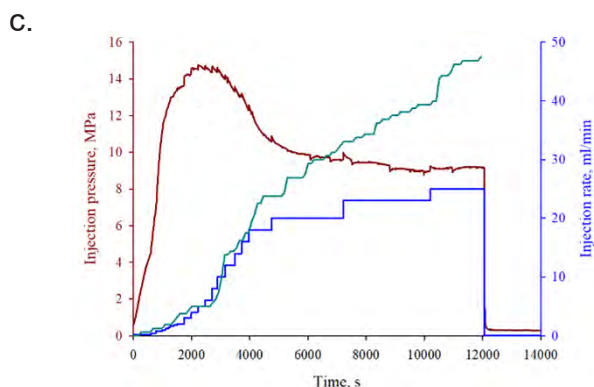
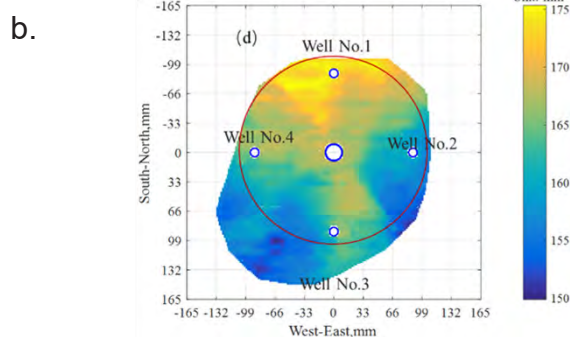
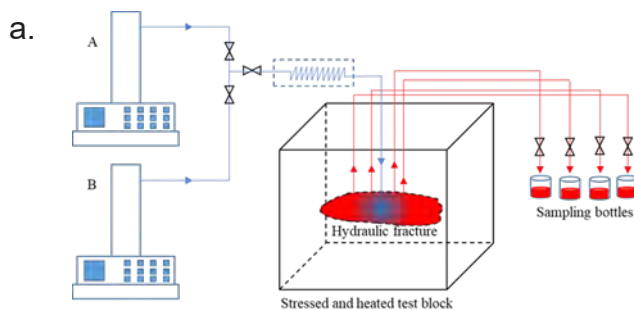


Figure 4. A lab scale ESG experiment from Hu and Ghassemi (2020): (a) the general set up; (b) the reconstructed hydraulic fracture geometry; (c) the injection pressure and rate; (d) the temperature in the injection and production wells.

to the crack faces, and the maximum thermal stress. For the case of wellbore stimulation, and considering the regime of relatively long crack growth, the number of initial cracks has a small

Thermo-poroelastic hydraulic fracture opening and injection pressure variations

Coupled thermo-poroelastic effects are also

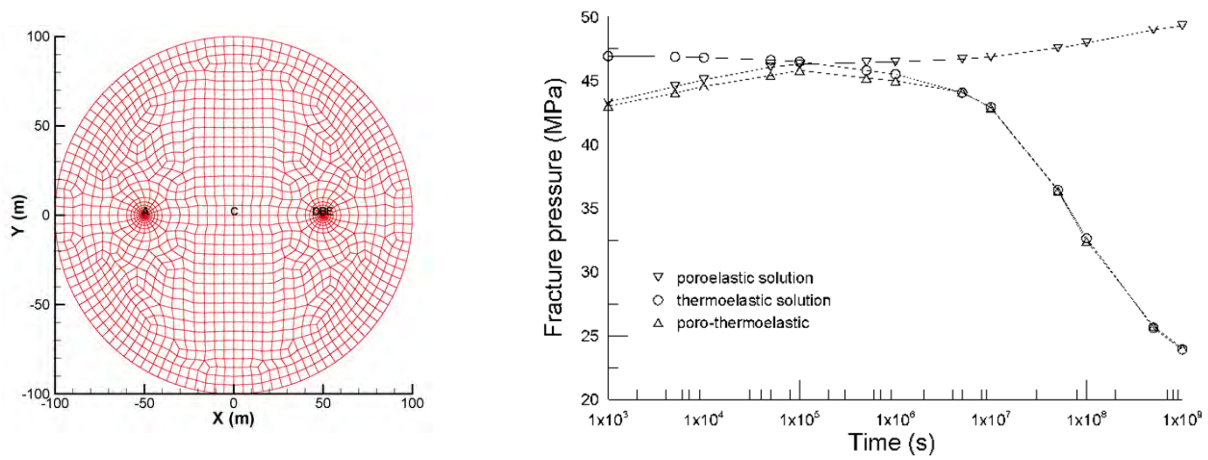


Figure 5. (left) discretization of a circular planar fracture, where A is fluid injection well and B is fluid extraction well; (right) comparison of fluid pressures at the location of point A from the poroelastic, thermoelastic, and thermo-poroelastic models during the fluid injection and extraction process (Ghassemi and Zhou, 2011).

manifested in injection pressure variations with time. This is mainly rooted in the fracture aperture change resulting from poroelastic dilation and thermoelastic cooling. The latter is the dominant

mechanism in most geothermal circumstances (see e.g., Ghassemi and Zhang, 2006; Zhou and Ghassemi, 2012). The response of a fracture to cooling is depicted in Figure 3 for a 2 m long Griffith

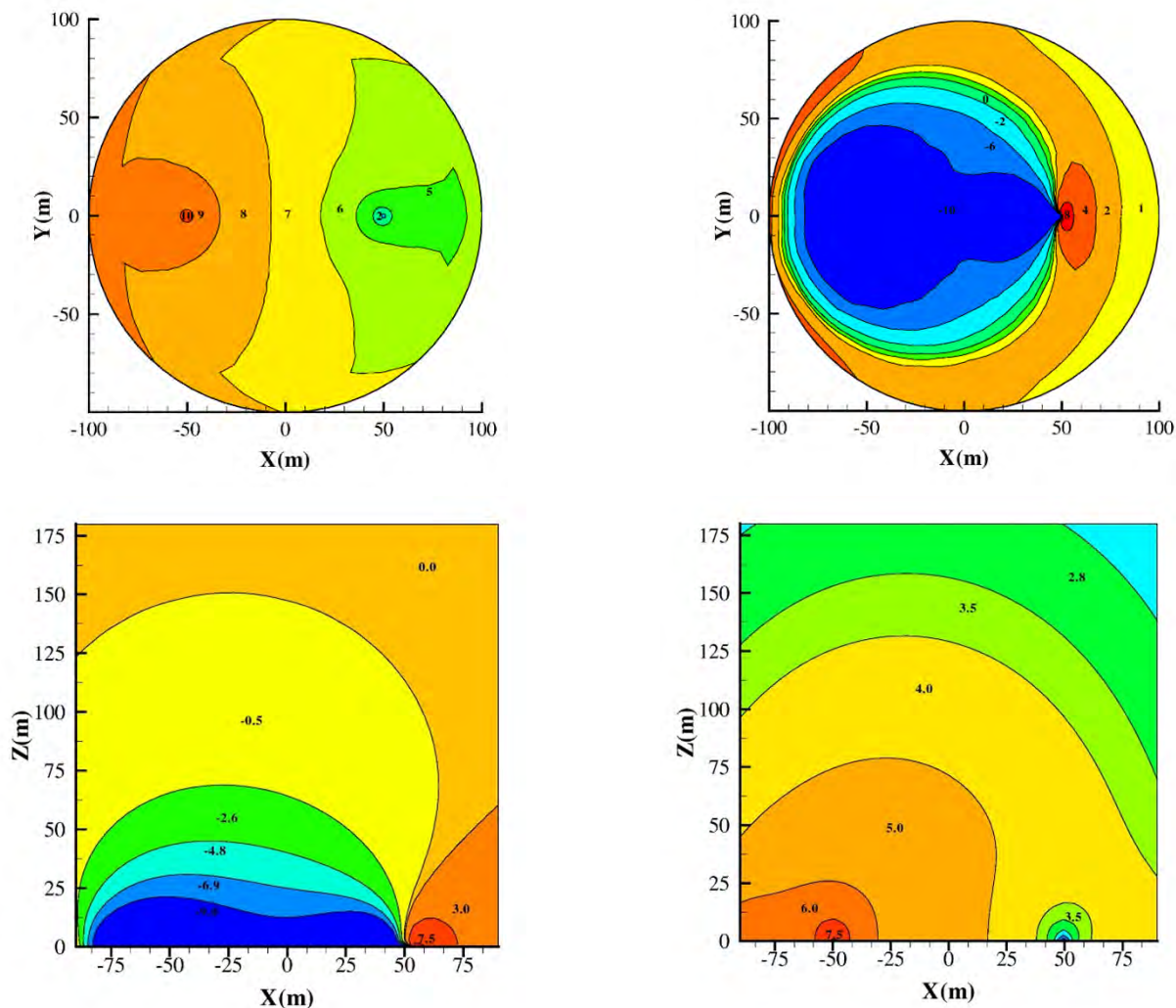


Figure 6. The stresses (in MPa) induced due to poroelastic and thermoelastic effects during circulation. Top row: fracture plane. Bottom row cross section between the two wells. It is important to note that the magnitudes of σ_{zz} thermal stress component are only slightly higher than those caused by pore pressure. However, the values of induced tangential components (σ_{yy} , σ_{xx}) would be an order of magnitude higher (Rawal and Ghassemi, 2014).

fracture in Westerly granite whose surfaces are continuously cooled from 200°C to zero.

This cooling-induced fracture opening can reduce the injection pressure. The phenomenon of injection pressure decrease during cold water injection has been demonstrated in a laboratory EGS experiment (Hu and Ghassemi, 2020) and is shown in Figure 4. Despite the fact the injection rate was increased in the experiment, the injection pressure continued to decline while the fracture remained stationary.

Such a response has also been captured in numerical simulations of circulation in a fracture or fault as shown in Figure 5. The fracture aperture responds to both pore pressure and cooling during circulation. This is evident for the injection pressure at point A on the circular fracture (Figure 5a) in granitic rock. In this case, the thermoelastic stress significantly reduces the injection pressure, overwhelming any poroelastic effect associated with the rock matrix dilation.

Continued circulation in the fault perturbs the pore pressure and stress fields in the surrounding rock. An example of the induced poroelastic and thermoelastic stresses in the reservoir matrix in the cross-section A-B through the injection/production wells of Figure 5 is shown in Figure 6 after 1 year of operation. The contributions of thermoelastic and poroelastic stress to the total stresses are opposite, as expected. Compressive poroelastic stresses occur around the injection well. In this example, the maximum value of thermoelastic σ_{zz} stress component is ~9 MPa around the injection well. Additional zones of enhanced compression are induced behind the extraction wells. This is the effect of strain compatibility and is more pronounced for the axial stress component. The compressive stresses only exist around the back of the extraction well and above the fracture surface ahead of the cooling front, which moves into deeper places with time. The induced compressive and tensile stresses can contribute to rock failure in shear and tension, resulting in increased seismicity in this region. The thermal stress can destabilize the fault and any favorably oriented natural fractures in its vicinity, and may contribute to induced seismicity (see e.g., Ghassemi and Tao, 2016; Safari and Ghassemi, 2014). The poroelastic stress on the other hand, tends to be stabilizing on the main fracture and their effects on the neighboring

fractures would depend on the stress regime and the natural fracture orientations.

Closure

Modeling advances make it possible to capture the impact of a range of coupled processes during reservoir creation planning, as well as when monitoring of the stimulation outcomes. 3D fully coupled models with DFN capabilities are also available and have been used to treat EGS problems. However, material properties appearing in the relevant constitutive equations are not readily available. This is the focus of a few Utah FORGE R&D projects which also provide unique opportunities for model calibration and validation.

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Short-Circuiting Mechanisms in Hot Dry Rock Geothermal Methods

Submitted by Bruce Gee, Robert Gracie, and Maurice Dusseault; University of Waterloo; Waterloo, Ontario

Introduction

Enhanced Geothermal Systems (EGS) may provide new access to the thermal energy trapped within the Earth's crust. Extracting heat from deep rocks has, until now, required a rock mass both naturally hot and permeable, so that hot fluid can be extracted at commercially interesting rates. In an EGS (also called a Hot Dry Rock (HDR)) installation, a low permeability hot rock mass is flow-enhanced through engineered stimulation (hydroshearing, fracturing) to create a network for flow and heat exchange.

The long-term viability of EGS installations is impacted by short-circuiting -- a natural consequence of the positive feedback loop created by the non-linear thermo-hydro-mechanical (THM) interactions within the rock mass. Short-circuiting is a multi-scale phenomenon in which initially dispersed flow devolves to limited pathway flow between injection and production wells, reducing surface area where heat transfer can occur. This causes the production fluid temperature to sharply (and unexpectedly) decrease.

The multi-fracture EGS doublet systems considered in our modeling [1] consist of a single injection and production well, hydraulically connected by discrete fracture planes, as shown in Figure 1.

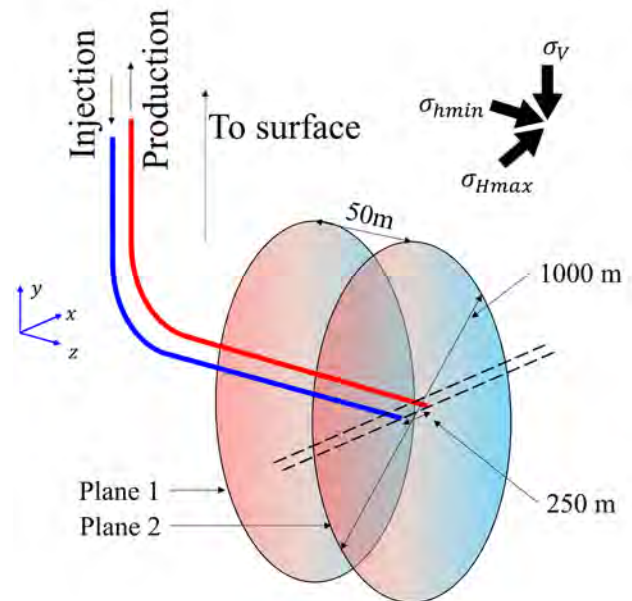


Figure 1. Schematic diagram of a one- and two-fracture EGS system at a depth of 1800m.

Thermo-hydro-mechanical Feedback Process

The processes of interest for short-circuit development are: heat transfer in the rock mass and to the circulating fluid; fluid flow through the rock mass fracture network; and, thermoelastic contraction of the rock mass. Short-circuiting develops because of interaction of these processes, with positive feedback.

When cold fluid is circulated through a fracture network, the fluid disperses and gradually heats up to the temperature of the rock mass along the way. Dense crystalline rocks may be assumed impermeable, so flow is restricted to the discrete fracture planes [1]. The rock mass cools as heat is extracted by the circulating fluid, but cooling is non-uniform, with the greatest cooling occurring around the injection well, creating a thermal gradient in the rock mass. Rock mass heat loss causes thermoelastic contraction.

A temperature change alters the volume of solid rock: an increase causes expansion, a decrease causes contraction. As the temperature distribution throughout the rock mass is non-uniform, so too is the thermal contraction and resulting deformation. The areas which undergo

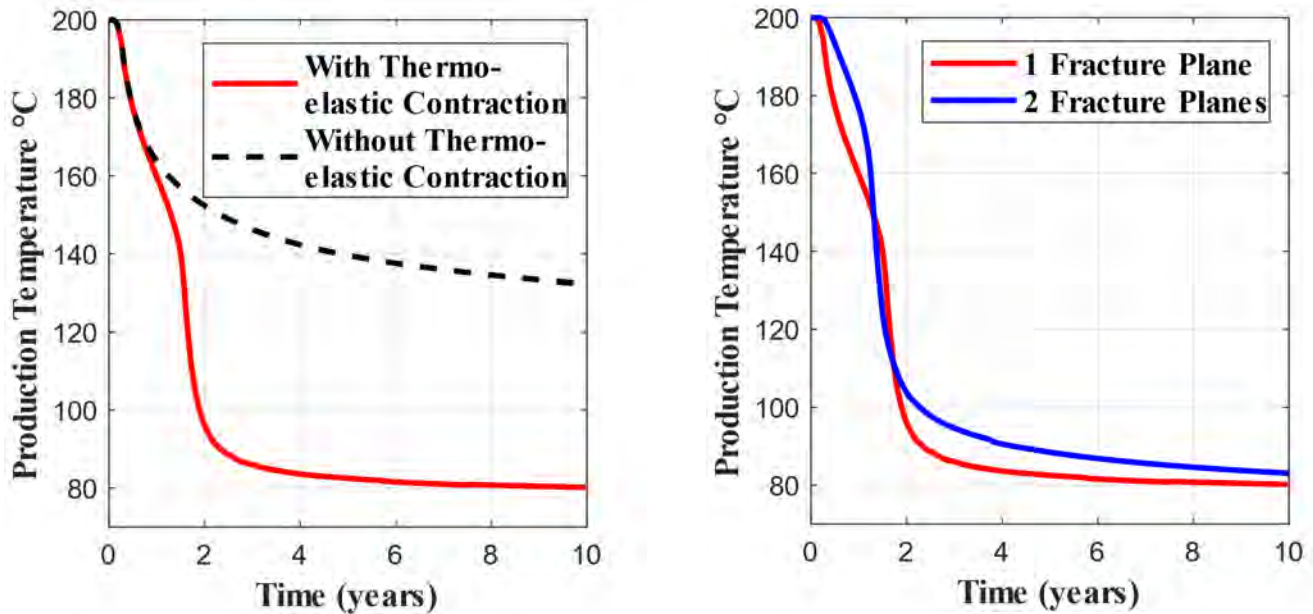


Figure 2. Production fluid temperature from a single fracture EGS with short-circuiting effects (left) and a comparison of a one-fracture EGS and a two-fracture EGS with 50 m fracture spacing (right).

the most cooling also undergo the most thermal strain, leading to a significant increase of the fracture aperture localized to the cooled areas.

As fracture aperture increases from thermal contraction, this deformation feeds back into the fluid flow behavior. The hydraulic conductivity of a fracture is proportional to the cube of fracture aperture: an increase in aperture leads to a much larger increase in hydraulic conductivity. Like in

a network of pipes, increasing the diameter of a single pipe will lead to a greater flow rate in that pipe and less flow through other pipes. Thus, as the cooled area fracture apertures increase, more fluid flows through that area. Flow is directed away from the hotter regions towards the already cooled region, which leads to even more cooling, more thermal contraction, and development of even larger apertures attracting more flow. The result is a significant reduction in EGS efficiency.

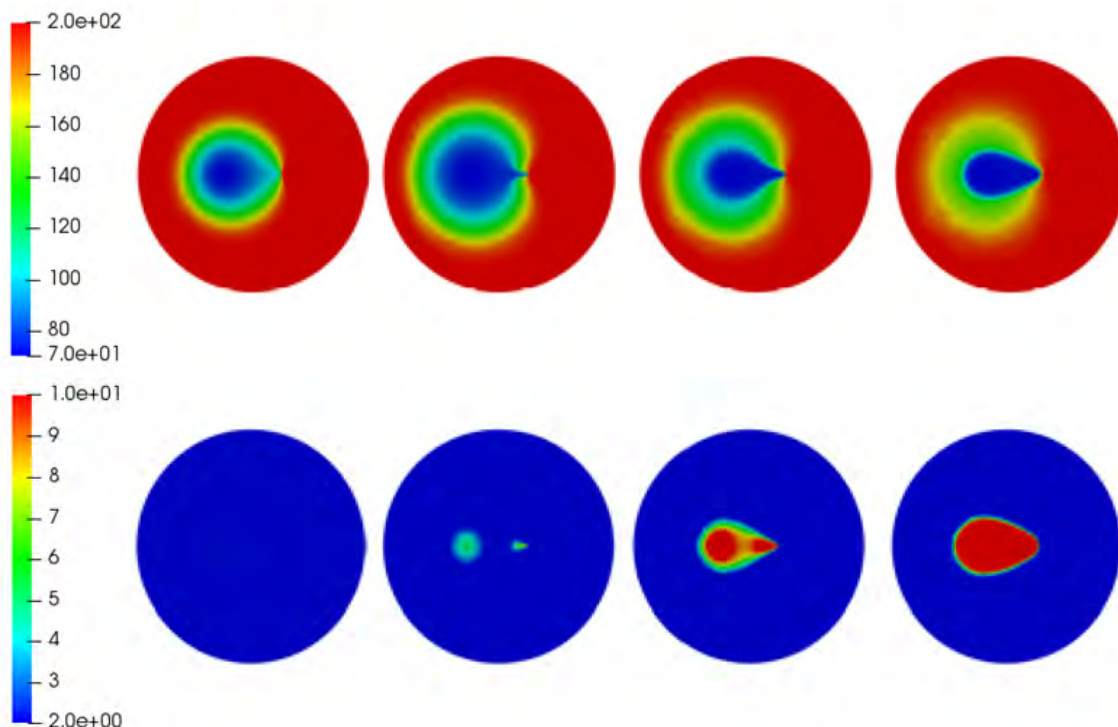


Figure 3. Fluid temperature [°C] (top) and fracture aperture [mm] (bottom) distributions over time in a single fracture EGS. The distributions are shown at 3, 12, 20, and 48 months.

The thermo-hydro-mechanical positive feedback loop is now clear: over time, a short-circuit is created in the EGS as flow concentrates along a constrained flow pathway and is unable to access the heat elsewhere in the system. This basic feedback loop is a complex process and occurs at multiple scales within the reservoir -- short-circuiting occurs not just between fractures, but also within a single fracture itself.

In-plane short-circuiting mechanisms

Short-circuiting within a single plane is also known as flow channeling [2]. Figure 2 shows the production temperature from an EGS doublet system connected by a single fracture. Fluid is circulated at 50 L/s through rock with a minimum in-situ stress of 26 MPa and an initial rock mass temperature of 200°C. The initial temperature decrease is a result of fluid drawing heat away from the fracture surfaces faster than it can be replenished by thermal diffusion. A secondary temperature decrease occurs at 1.5 years, which is attributed to the development of short-circuiting within the fracture plane. Heat extraction from the same system without considering the coupled effects of mechanical deformation is also shown, illustrating how neglecting the mechanical deformation vastly overestimates the amount of energy that can be extracted from the system.

The development of an in-plane short-circuit is illustrated in Figure 3. Initially, flow is evenly dispersed throughout the uniform aperture fracture. Circulation-induced cooling leads to increased aperture development around the injection and production wells. With time, these regions of increased aperture expand and connect to create a channel of increased aperture between the injection and production wells. Flow concentrates along this channel, leading to the rapid decrease observed in the production fluid temperature. Flow channeling occurs in both single and multiple fracture wells. In a multiple fracture system, flow is dispersed throughout the fractures and flow through any given fracture is lower than in the single fracture case (assuming the same injection rate). However, the distributed heat loss throughout the rock mass disperses the thermal strain throughout the rock mass, while the stiffness of the rock mass is decreased because of the presence of more fractures. This combination results in increased contraction of the rock mass, which creates

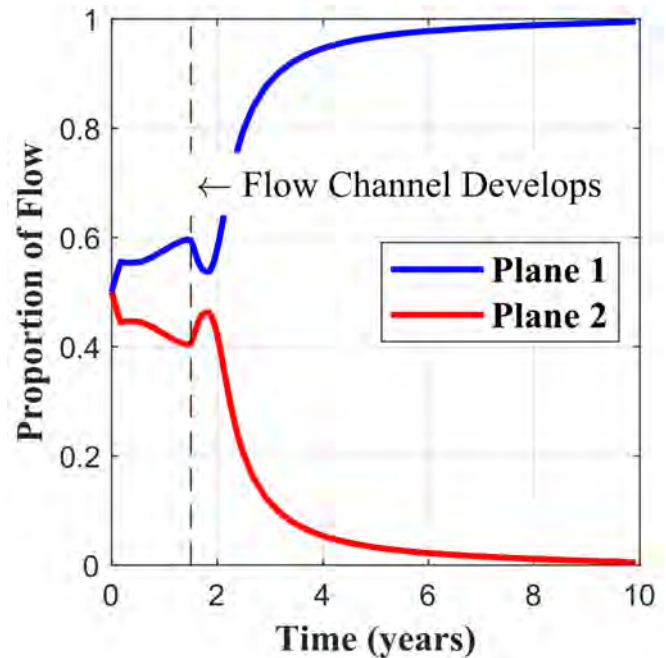


Figure 4. Fluid rate redistribution in a two-fracture EGS with 50 m fracture spacing.

greater aperture growth than a single fracture. Figure 2 also shows a comparison of production temperature for a one- and two-fracture EGS. While the two-fracture EGS maintains a higher production temperature at the start, the onset of short-circuiting occurs at approximately the same time in this case. Increasing fracture spacing is advantageous for flow channeling as it decreases the interaction between fractures, but increased fracture spacing also exacerbates the inter-plane short-circuiting mechanism, plane channeling.

Inter-plane short-circuiting mechanisms

Short-circuiting between planes is known as plane channeling [2]. Even amongst two parallel initially identical homogeneous fracture planes, a natural asymmetry to the system is created by the resistance of the well casing linking the fractures. As the THM feedback loop reduces the hydraulic resistance of the planes, the asymmetry of the system diverts more flow through the plane with the shortest flow path between the system inlet and outlet. Plane channeling has positive feedback interactions with flow channeling, and over time flow becomes dominated by a single fracture plane. Figure 4 shows the temporal distribution of flow between two fractures. Initially, flow is evenly split, but plane channeling then starts to divert flow into plane 1. Once a flow channeling short-circuit develops, this process accelerates dramatically, and the flow is eventually directed entirely through the first plane.

Plane channeling effects are not reflected in the production temperature. The decrease in temperature illustrated in Figure 2 coincides with the development of flow channeling in a single plane. Thus, while plane channeling has significant effects on the nature of flow within the reservoir, flow channeling is the dominant short-circuiting mechanism affecting the production temperature.

Conclusions

Short-circuiting has negative implications for EGS viability, but it is possible to mitigate its effects. Controlling key parameters like flow rate and well spacing can help delay the development of flow and plane channeling. Another key parameter is reservoir depth: in deep reservoirs with high in-situ stresses that exceed the induced thermal stress changes, it may take up to a decade for short-circuiting to start negatively impacting the heat extraction process [2]. In shallower wells in which the induced thermal stress dominates, as illustrated herein, short-circuiting develops sooner, necessitating the need for in-well and/or inter-well flow control. Both zoning and heat mining accept the inevitability of short-circuiting by operating a section of an installation for a period of time, then allowing natural replenishment and partial recovery of the section through internal rock mass heat redistribution. In zoning, flow in a multi-fracture doublet well system would be restricted to a single fracture at a time, while in heat mining, wells in a cluster are operated on rotation, with one in operation while others recover.

EGS holds great potential as a clean renewable source of energy but short-circuiting compromises its economic viability. Understanding the physics of short-circuiting over time is crucial to the design and operation of successful EGS installations.

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Channeling in Enhanced Geothermal Systems

Submitted by Rafael Villamor-Lora and Herbert H. Einstein, Department of Civil & Environmental Engineering, Massachusetts Institute of Technology

Introduction

The study of flow and transport in rough, fractured media is essential in the development of new energy technologies including enhanced geothermal systems (EGS) (Gonçalves da Silva, 2016) and CO₂ sequestration (Li et al, 2021). This is a complex problem, mostly due to the number of interacting physical processes in the fractured environment (Figure 1).

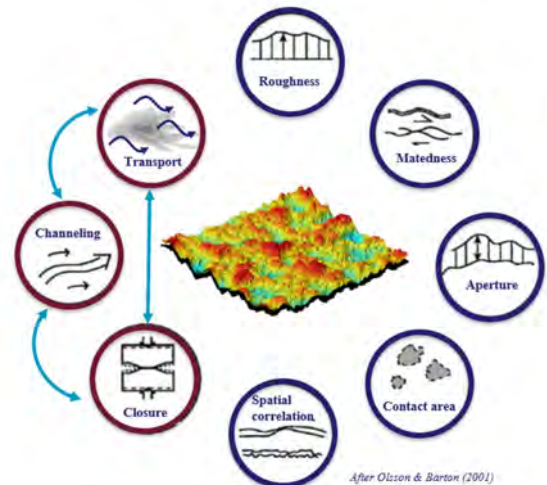


Figure 1 – Interaction of processes - the geometric features in rough fractures exert control on fracture deformation, flow channelization and mass and heat transport. The spatial structure of the void space depends on a series of parameters including the intrinsic surface roughness and the matedness degree between the upper and lower surfaces.

Past laboratory and field investigations have shown that the flow in stressed, rough fractures tends to concentrate into a few preferential pathways, i.e., channels (e.g., Tsang and Neretnieks, 1998). This has important implications on the permeability evolution, flow shortcircuiting (Berkowitz, 2002), and mass and heat transport processes (Kang et al, 2016). Understanding the interplay between channelization and flow and transport mechanisms is key for production forecasting models and reservoir characterization (Hawkins et al, 2018). Flow channelization may occur at the fracture network level (e.g., leading to undesired flow short circuits in EGS), but also at the single

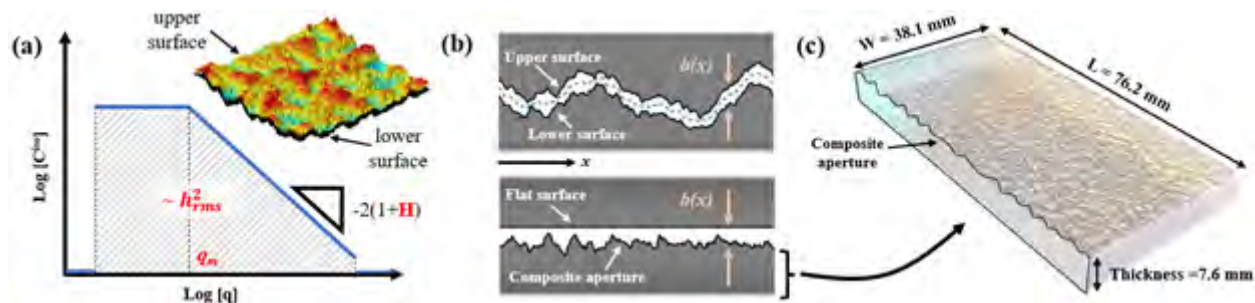


Figure 2. Digital fabrication of fracture analogs. (a) Two self-affine, rough surfaces are generated using the Brown (1995) method. The model depends on three parameters: the Hurst exponent, H , which controls the surface roughness; the mismatch frequency, q_m , which defines the matedness degree; and the root-mean-square of heights, h_{rms} , which sets the scale. (b) The hydromechanical behavior of two rough surfaces in contact is equivalent to that of a flat surface in contact with a rough one defined as the composite aperture. (c) 3D-printed deformable specimen used in the experiments.

fracture scale. In the field, fractures are usually conceptualized as flat features. However, they are intrinsically rough. This, along with a given matedness degree between the upper and lower fracture surfaces, results in heterogeneous aperture fields, with several asperities being in contact. The resulting spatial structure (Brown and Scholz, 1985), in turn controls fracture deformation, flow channelization, and mass and heat transport (Figure 1).

To investigate the interplay of these physical processes, we are conducting a series of numerical simulations and mili-fluidic experiments using transparent fracture analogs.

1995). From the local separation between the upper and lower surfaces we determine the composite (or local) aperture map (Figure 2b). Previous research (Brown, 1995) has shown that the hydromechanical behavior of two contacting rough surfaces is equivalent to that of a flat surface in contact with a rough surface defined as the composite aperture, and this we adopt in our tests. For the experiments reported here, we use 3D-printed prismatic (1.5" x 3.0" x 0.3"), transparent fracture analogs with a rough face corresponding to the composite aperture topography (Figure 2c).

The fracture analogs are subjected to varying

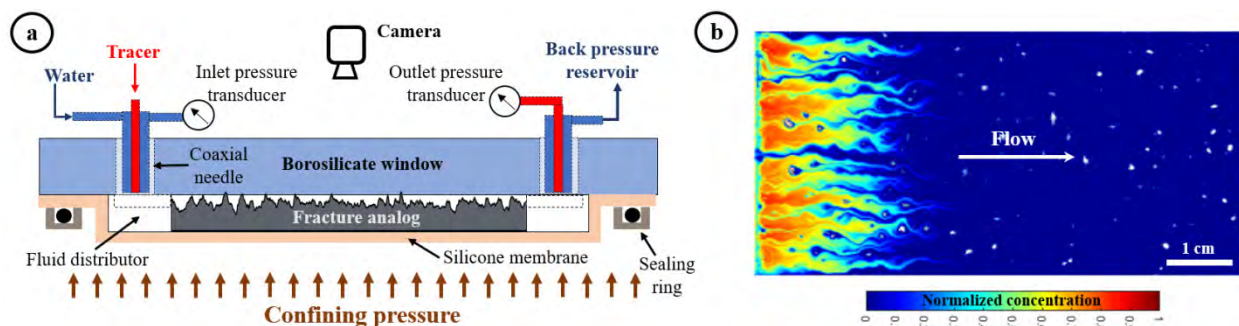


Figure 3. (a) Side view of our pressure-controlled Hele-Shaw cell. The cell is composed of a rigid, flat borosilicate window and a deformable 3D-printed specimen. A scientific monochrome camera is used to record the light intensity from the cell during the experiment. (b) Snapshot of a tracer injection experiment where a dyed fluid is continuously injected from the left boundary. Light intensity images are converted into aperture and concentration maps using the Beer-Lambert law. Note how the flow channelizes due to the variable aperture geometry. The white patches represent contacting asperities.

Experimental Setup

To facilitate the visualization of the physical processes we use transparent fracture analogs instead of natural rocks. Our specimens are designed and fabricated such that they exhibit spatial structures similar to those of real rocks. We adopt a digital fabrication approach where spectral methods (Figure 2a) are used to generate two mated self-affine surfaces (Brown,

normal stresses to cause fracture deformation while simultaneously observing flow through the fracture. This is done in a pressure-controlled Hele-Shaw cell (Figure 3a). The cell is composed of a borosilicate glass window and a deformable 3D printed specimen. Through two coaxial needles we inject distilled water/dye tracers and measure the fluid pressures. The normal stress is applied at the bottom face as a uniform confining pressure. Note that the normal stresses applied to the

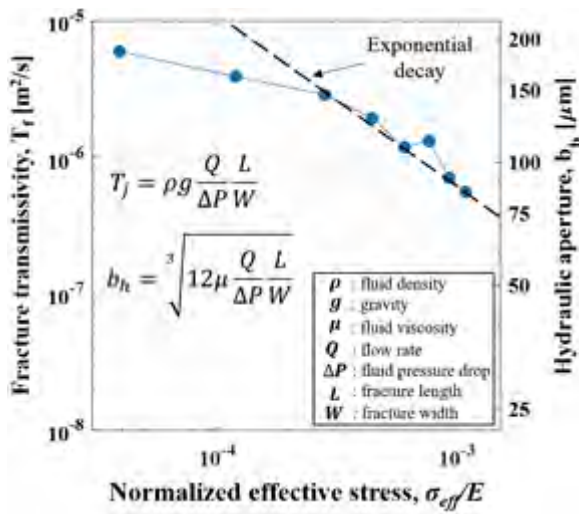


Figure 4. Pressure-dependent permeability of a fracture analog as a function of the normalized effective stress. Here $\sigma_{eff} = CP - p_{avg}$, where CP is the confining pressure, and p_{avg} is the average fluid pressure at the center of the fracture. As the fracture closes under increasing normal stress, the hydraulic impedance ($Q/\Delta P \cdot L/W$) becomes larger. This results in decreasing fracture transmissivity and hydraulic aperture. Note that the hydraulic aperture is different than the geometric (or mechanical) aperture, and it could be understood as the available space for advective flux.

Experimental Results: Pressure-dependent Permeability and Fracture Closure

To explore the evolution of permeability and transport properties with fracture closure, we subject the fracture analogs to a stepwise stress path. At each pressure step, under constant effective stress, σ_{eff} , we inject distilled water at different flow rates, Q , and measure the fluid pressure drop between the inlet and the outlet, Δp .

Figure 4 shows the pressure-dependent permeability of one rock analog defined in terms of the fracture transmissivity, T_f , and the hydraulic aperture, b_h (Witherspoon et al., 1980). The experimental results show similar behavior to those observed with real rocks including exponential decay with normal stress.

Once the permeability measurements are done, and before increasing the confining pressure to the next pressure step, we continuously inject dye tracers into the fracture and monitor the process with a digital camera (Figure 3b). The relative

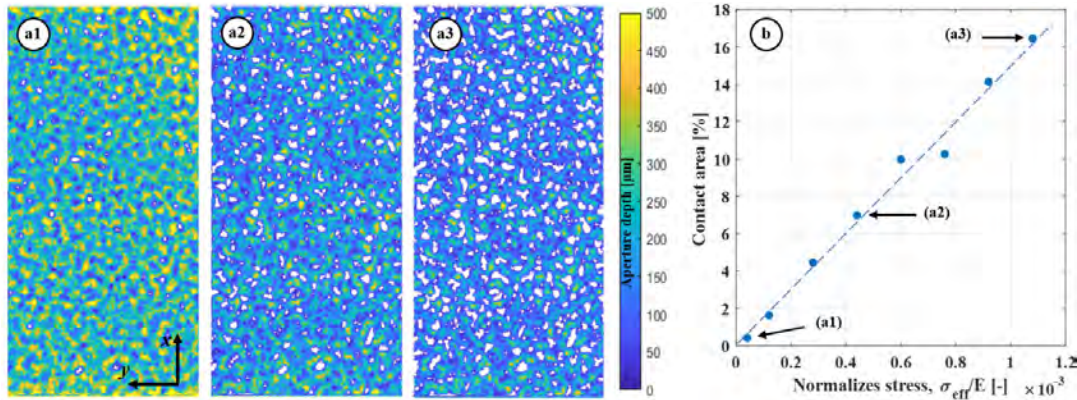


Figure 5. (a) Measured aperture maps under three different normal stress levels: $\sigma_{eff}/E \sim 4 \times 10^{-5}$, 4×10^{-4} , and $\sigma_{eff}/E \sim 10^{-3}$. White patches represent contacting asperities (b) Evolution of contacting asperity area as a function of the normalized stress. Our experimental results show linear increase with normal stress as observed in previous investigations in tribology and rock mechanics (Zou et al., 2019).

specimens, σ_{lab} , must be scaled according to the Young's modulus of the 3D-printed material, E_{lab} , to maintain a stress-stiffness ratio relevant to field conditions, i.e., $\sigma_{lab}/E_{lab} \sim \sigma_{field}/E_{field}$. Light is transmitted from the bottom, and a monochrome camera is used to continuously record the light intensity in the cell during the experiment. The measured light intensity maps are then converted into aperture and concentration fields (Figure 3a) using the Beer-Lambert law (Glass et al., 1991; Villamor-Lora et al, 2019).

changes in light intensity in the cell are then used to obtain the aperture and concentrations maps.

Figure 5a shows three aperture maps measured under different normal stress levels. Note how, as the fracture closes under increasing normal stress, the contacting asperities grow in number and size. One can use the information from these aperture maps to determine different geometric characteristics (e.g., univariate aperture distributions, fracture -volumes and -closure, or contact areas as shown in Figure 5b), and, also, to further analyze the aperture structure through

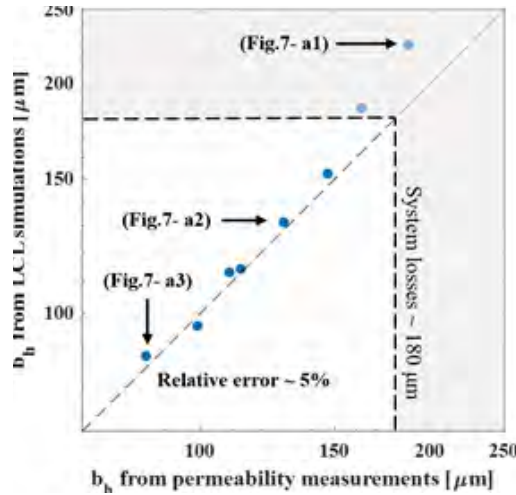


Figure 6. Comparison between the hydraulic aperture estimates obtained from Local Cubic Law, LCL, simulations and those derived from hydraulic (permeability) measurements. Note that hydraulic aperture measurements greater than 180 μm are comparable to hydraulic losses of the system, and therefore subjected to larger experimental errors.

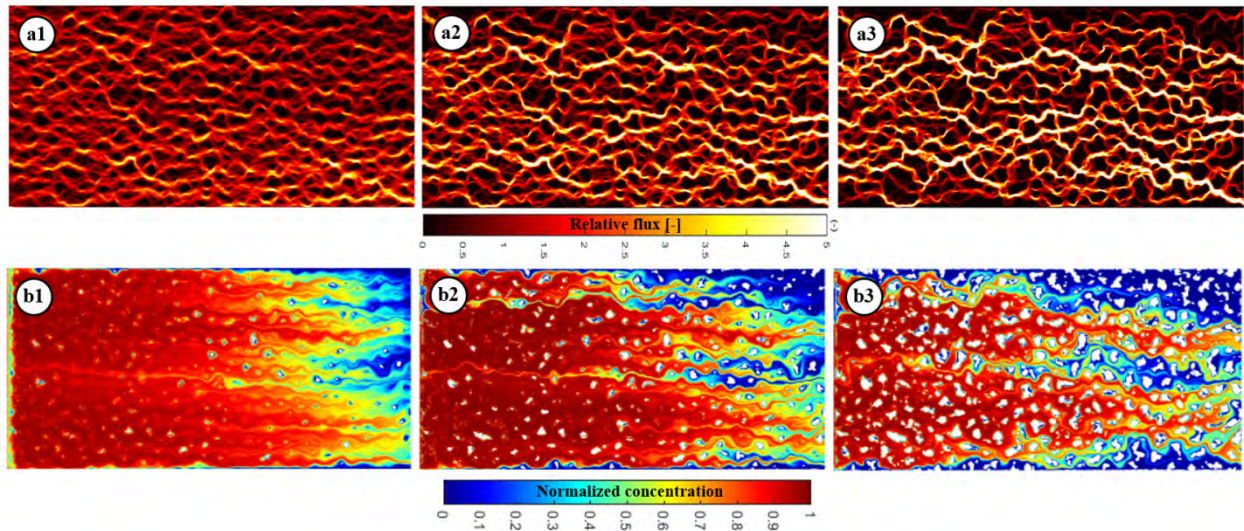


Figure 7. (a) Simulated flow fields corresponding to the aperture maps in Figure 5a. Note that the fluxes are normalized relative to the uniform flux [$q_{\text{rel}} = q_{ij} / q_{\text{uniform}} = q_{ij} / (Q_{\text{in}}/n_y)$], where the relative fluxes in each pixel, q_{rel} , are computed by normalizing the local fluxes from numerical simulations, q_{ij} , by the inlet flux, Q_{in} , divided by the number of pixels along the fracture width, n_y . Numbers above 1 indicate channelization and numbers below 1 represents low velocity in stagnation areas. (b) Experimental concentration maps after the injection of 1 fracture volume under the flow fields shown in (a). White patches represent contacting asperities.

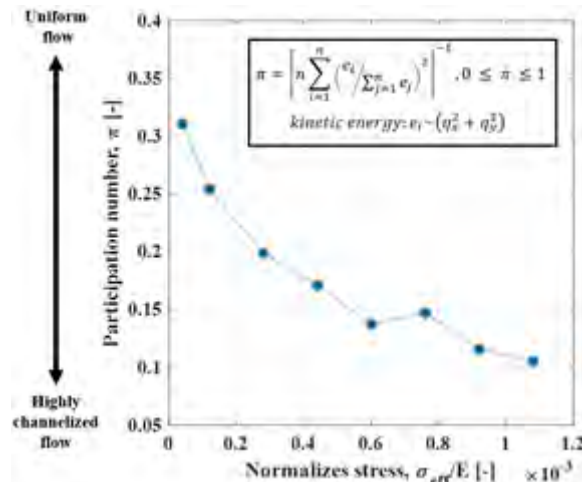


Figure 8 – Evolution of channelization with increasing normal stress. As the fracture closes under normal stress, more and more asperities are in contact, the flow field becomes more heterogeneous and channelized into preferential paths.

geostatistical and spectral methods.

Flow Simulations – Determination of the Flow Field and the Channeling Degree

We conducted a series of numerical simulations to determine the flow field; for this we use the measured aperture fields (Figure 5a) as inputs. Applying the Local Cubic Law, LCL, one can convert the aperture maps into permeability fields and then solve the pressure equation to determine the evolving flow field (Brown, 1987). Moreover, LCL simulations also allow one to obtain a second estimate for the hydraulic aperture (i.e., a permeability value independent from the hydraulic measurements). Our results show excellent agreement between numerical simulations and flow experiments (Figure 6), with an average error of 5%, suggesting that the Reynolds equation holds in our tests (Brush and Thomson, 2003).

The results of the simulations in Figure 7a show how the flow channelizes with increasing closure due to normal stress. With increasing channelization, the flow field becomes more heterogeneous, flow pathways grow more tortuous and get dominated by larger and larger flow rates, and the number of low velocity and stagnation zones also grow in number and size. All this has a deep effect on mass transport in the fracture. Figure 7b shows the experimental concentrations maps after the injection of one fracture volume corresponding to the flow field conditions shown in Figure 7a.

Finally, we use the simulated flow fields in Figure 7a to quantify the channelization degree in the fracture in terms of a participation number, π , that represents the distribution of the kinetic energy within the fracture (Andrade et al, 1999). Figure 8 shows the evolution of channelization with increasing normal stress. The participation number ranges from 1 (for uniform flow) to 0 (for highly channelized flows); it is a good alternative to build relationships between a global channelization degree and flow and transport properties.

Conclusions

In this paper we describe a series of experiments conducted using a novel pressure-controlled Hele-Shaw cell. With this setup, one can investigate different fracture processes and obtain high-

spatial and –temporal resolution measurements of fracture deformation and flow. We also conducted a series of simulations to determine the flow fields and the evolving channelization degree with increasing normal stress. Our analysis then shows excellent agreement between experimental results and flow simulations.

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Induced Seismicity in Low-Temperature Geothermal Development

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Introduction

The Western Canadian Sedimentary Basin (WCSB), one of the largest oil and gas basins in the world, covers ~1,400,000 km² of southwestern Manitoba, southern Saskatchewan, Alberta, northeastern British Columbia. The area also contains large geothermal energy resources. To enhance energy extraction from the WCSB, hydraulic fracturing is being used extensively. Hydraulic stimulation is typically accompanied by seismicity because injection changes pore pressures and temperatures, facilitating slippage of fractures and faults. In non-steam geothermal processes, rapid widespread pore pressure changes and slow temperature changes lead to increased deviatoric stresses, resulting in seismicity. The anthropogenic seismicity for this area includes some of the largest MW values reported globally, including events near Fort St. John of MW 4.6 on 17 August, 2015, and MW 4.2 on 30 November, 2018.

The Montney Formation in western Alberta and northeastern British Columbia serves as a proxy for sedimentary basins with similar low-temperature geothermal resources as a case study for this work. We define a geomechanical zoning or stress domain model based on pore pressure variation in the Montney Formation. We then assess all mapped faults as potential sites of injection-induced seismicity. In each stress domain, we constrain uncertainties associated with each effective uncontrollable geomechanical parameter, such as stress tensors, pore pressure, multiple fault/fracture orientations, and frictional strengths. Monte Carlo simulations are applied to assess the potential slip tendency of local faults. We apply a probabilistic assessment to investigate the potential fault slip tendency due to HF in the Montney Formation, incorporating the uncertainty distributions associated with Mohr-Coulomb strength parameters.

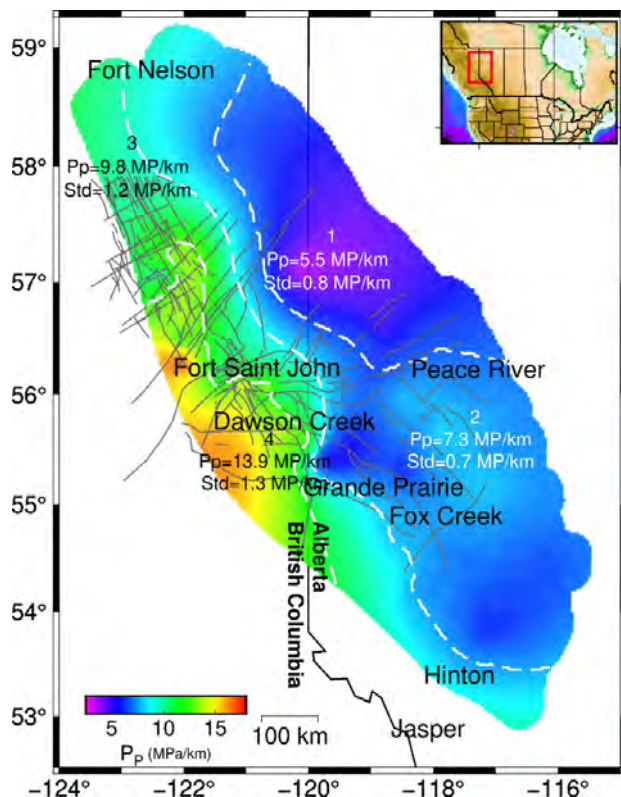


Figure 1: Spatial pore pressure gradient values in the Montney Formation. Gray lines indicate faults crossing one another in the Montney play. The white dashes show the zoning of the Montney Formation based on pore pressure gradients at various locations.

State of stress in the Montney Formation

Pore pressure is an integral part of the state of stress in a region. Different studies have shown that pore pressure distribution in the Montney Formation is hydrologically subdivided and, consequently, the Formation is compartmentalized. Spatial variations of the pore pressure gradient indicate that the deeper, western side of the Formation (in British Columbia) has a higher value than the shallower, eastern side (in Alberta) [1]. Many wells drilled in the Montney Formation have undergone a Diagnostic Fracture Injection Test (DFIT) or mini-frac, which provides reliable determinations of minimum in situ stresses. The S_{hmin} gradients extracted from DFIT tests indicate that minimum principal stress magnitudes are slightly higher on the British Columbia side than in Alberta, similar to the case for spatial pore pressure gradient values. Based on pore pressure zoning and the available minimum principal stress datasets, we have derived statistical measures of the S_{hmin} magnitude variables in each stress domain.

We have used the injection-induced earthquake focal mechanisms recorded in the WCSB to constrain the maximum principal stress

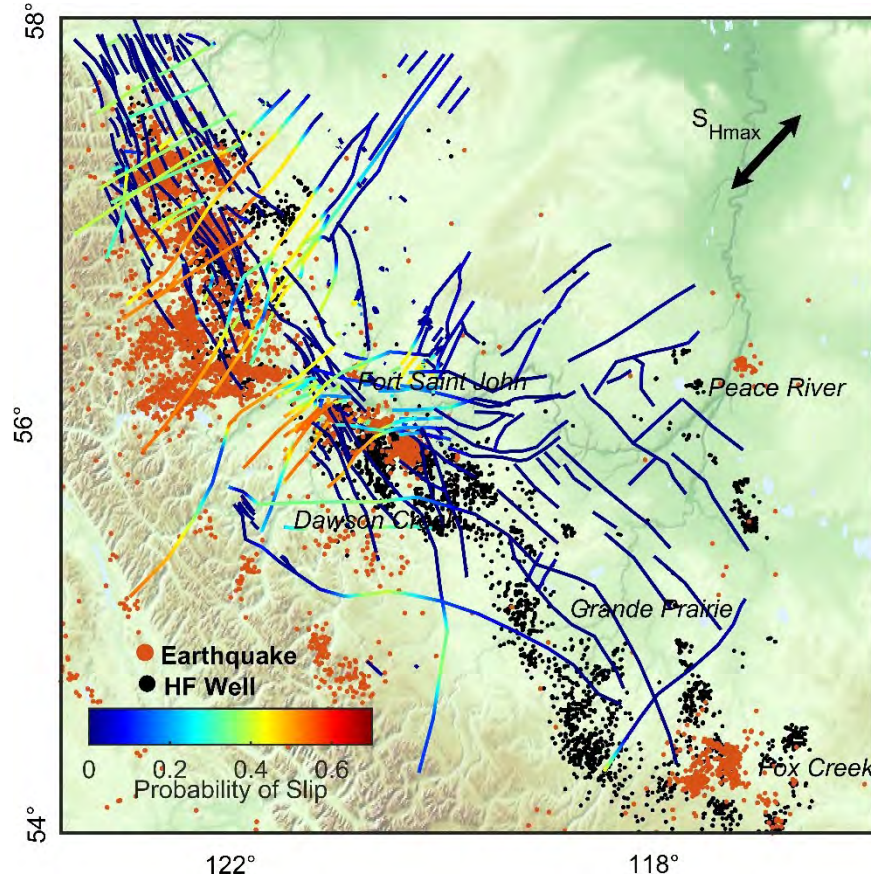


Figure 2: Fault map color-coded to highlight the probability of slip in the Montney Formation. Black points represent wells that were hydraulically stimulated. The red circles are seismicity reported by [3] and [4].

magnitudes. Applying Simpson's approach [2] to the combined 107 compiled focal mechanisms revealed that a strike-slip fault system is the dominant tectonic regime in the area, with an average Anderson fault parameter of $A\phi \approx 1.5$. In this study, based on available borehole stress orientation indicators from WSM, we have assigned a mean of 45° and a standard deviation of 5° to S_{Hmax} azimuth in all stress domains.

Assessment of Fault-Slip Potential

The probability of failure can be defined as $P_f = P[\tau - \mu\sigma_n \leq 0]$. For each fault patch, a Monte Carlo simulation with 10,000 scenarios has been applied to evaluate the slip tendency of faults in the Montney Formation. The analysis includes uncertainty associated with the uncontrollable subsurface parameters, such as the state of stress, pore pressure, pre-existing fault/fracture orientation, and frictional strength.

The result is a cumulative distribution of the probability of slip for each mapped fault. For each fault segment, we calculated the probability of slip in response to 2 MPa pore pressure perturbations ($\Delta P(P_{inj} - P_p) = 2 \text{ MPa}$). Different geo-mechanics parameters have been applied for each fault with respect to the location of the fault and the geo-mechanical stress domain. Figure 2 shows faults mapped in the study area color-coded with the probability of slip. The red fault lines imply a higher likelihood of slip. Recorded earthquakes and wells drilled in the area are represented with black and red circles respectively.

The analysis shows a rather high likelihood of slip due to HF in the area around Fort St. John as well as in the northwestern Montney area. It is evident that HF operations are not the only factor causing injection-induced seismicity. This can be seen around Grande Prairie in Alberta, where more than 670 wells have been stimulated, but no significant induced seismic event has occurred because of the relatively low pore pressure gradients in both the Duvernay and Montney Formations or because existing faults are not in a critically stressed condition. Even in the high pore pressure gradient Kiskatinaw area, not all HF stimulation activities were associated with induced seismicity. Our results indicate that two important factors affect seismicity in the studied area: pore pressure gradient and fault orientation.

Conclusions

We have developed a probabilistic approach to determine the likelihood of fault slip as a function of injection pressure due to HF treatment in the Montney Formation. The probabilistic analysis demonstrates that most fault planes in the Kiskatinaw area and the northwestern Montney Formation would become unstable with only a modest change of pore pressure. However, some areas have only a low probability of slip, having relatively low pore initial formation pressures.

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In-situ Stress Measurements at the Utah FORGE Site

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Introduction

In 2018, the U.S. Department of Energy selected a location in south-central Utah near the rural community of Milford to develop and test the techniques required for creating, sustaining, and

monitoring Enhanced Geothermal System (EGS) reservoirs. The project is designated as the Frontier Observatory for Research in Geothermal Energy (FORGE). Since 2017, five vertical monitoring wells, the deepest to 9500 ft, and a highly deviated injection well, 16A(78)-32, have been drilled. The wells encountered temperatures up to ~230°C. The production well, 16B(78)-32, and another deep well (47-32) for tool testing, will be drilled in the future. (See Figure 1.)



Figure 1. Aerial view of the Utah FORGE site. Wells denoted in white have been drilled; wells in yellow will be drilled in the future. The dashed line is the surface projection of well 16A(78)-32 drilled at 65° to the vertical on an azimuth of 105°.

Since 2017, several injection tests have been conducted at the Utah FORGE site. In 2017 and 2019, injection tests were conducted in well 58-32, drilled vertically to a depth of 7536 ft. Figure 2 shows the bottomhole pressure and temperature during these 2017 injection tests. Later, in 2019, in this same well, tests were repeated in the 147 ft openhole section at the toe and carried out in the cased section of the well. In 2021, three injection cycles were performed in the 200 ft openhole section at the toe of the deviated well 16A(78)-32. These injection activities included pump-in/shut-in, pump-in/flowback, and step rate tests. Various methods were used to determine the fracture closure pressure from the injection tests. Fracture closure stress indicates the minimum in-situ stress (often horizontally oriented).

The temperature and pressure data from testing in all the wells described were interpreted using: 1) conventional methods associated with pump-in/shut-in and step rate tests, including G function (a function defined by pumping and shut-in time)

analysis, plotting pressure vs. $\sqrt{t}$, diagnostic log-log plots using pressure during extended shut-ins, ISIP (instantaneous shut-in pressure), and reopening pressure (Xing et al., 2020); 2) methods associated with pump-in/flowback tests (Xing et al., 2021); and 3) methods associated with bottomhole temperature signatures (Xing et al., 2022).

Closure stresses determination with conventional methods

Conventional methods refer to methods associated with pump-in/shut-in and step rate tests, including G function analysis, plotting pressure vs. $\sqrt{t}$, diagnostic log-log plots, ISIP and reopening pressure. These methods were used to interpret the closure stresses from pump-in/shut-in and step rate tests from both well 58-32 and well 16A(78)-32. Figure 3 shows the variation in inferred closure stress (expressed as a gradient using the true vertical depth) as a function of the pumped volume as determined from pump-in/shut-in step rate tests conducted in well 58-32. The plot shows that the closure stress gradient varies depending on the depth (Zone 1 and Zone 2 are vertically separated by 600 ft). In addition, the closure stress increases with the pumping rate/volume. This stress variation could indicate that poroelastic effects (“back stress”) and/or the presence of natural fractures may play an important role in the determination of fracture closure stress.

Closure stress determination with flowback tests

Flowback tests have an advantage over extended shut-in tests in that they can reduce the operational time from days to hours. Figure 4 describes a flowback test in well 16A(78)-32. Instead of a prolonged shut-in, a flowback test was conducted through a 1/64-inch choke immediately after pumping stopped. After 30 seconds of flowback, the well was shut-in for three minutes. This flowback/shut-in cycle was repeated until the surface pressure decreased below 500 psi. The procedure is similar to the flowback test proposed in Savitski and Dudley (2011). Both a stiffness method and a material balance time method (Zanganeh et al., 2020) were used to interpret the closure stress. The inferred closure stress gradient ranges from 0.71 to 0.73 psi/ft.

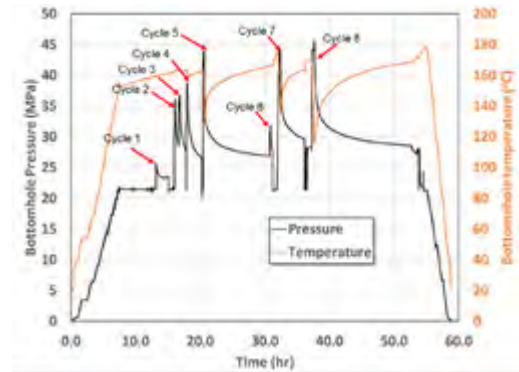
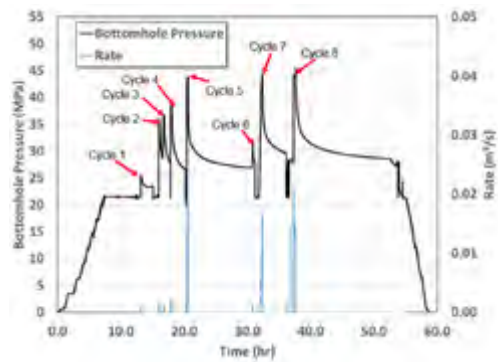


Figure 2. Bottomhole pressures and temperatures in well 58-32 during the 2017 injection program at the Utah FORGE site.

Closure stress interpretation using bottomhole temperature

We have proposed a method to determine a temperature signature that delineates the closure of a fracture. This allows inference of the closure stress from the bottomhole pressure that coincides with this temperature. After shut-in, the fluid leaks off into the formation through an effective matrix comprised of native permeability and flow through natural or induced fractures.

pressure-G function signatures. Consequently, a temperature-G function analysis can be a valuable method for inferring the minimum in-situ stress.

Conclusions

Three generic methods are used to interpret the closure stress from the injection tests at the Utah FORGE site. Pump-in/shut-in and step rate tests are easy to conduct in the field and can be interpreted using a variety of methods. However, for some cases, commonly applied conventional methods such as G-function analysis

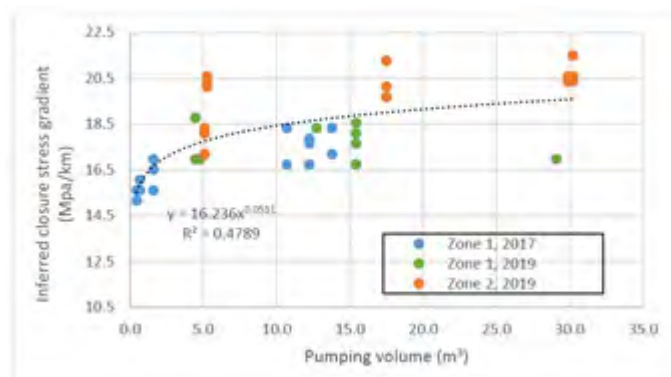


Figure 3. Inferred closure stress vs. pumping volume for the pump-in/shut-in tests in well 58-32.

This flow from a conceptualized main fracture is accompanied by advective heat transfer away from the wellbore and advective movement of cooler fluid from the wellbore into the fracture. The change of temperature before and after fracture closure results in distinctive inflection points on a plot of $G \, dT/dG$ vs. G , suggesting closure of the primary fracture. (G is the G-function time (refer to Nolte and Economides, 2000) and T is the temperature). From bottomhole temperature data collected during the 2017 injection tests in well 58-32, the temperature signatures are phenomenological and are less ambiguous than the

yield ambiguous results. Flowback methods reduce the operation time and offer a very useful supplementary or alternative approach for closure stress interpretation in naturally fractured reservoirs where there is tortuous communication between the wellbore and a natural fracture system. A newly proposed method using temperature signatures based on inflection points on plots of $G \, dT/dG$ vs G reduces uncertainties in the calculated stress gradient compared to some pressure-based analyses. The latter two methods are unproven, but the authors remain optimistic that they will be valuable diagnostic protocols.

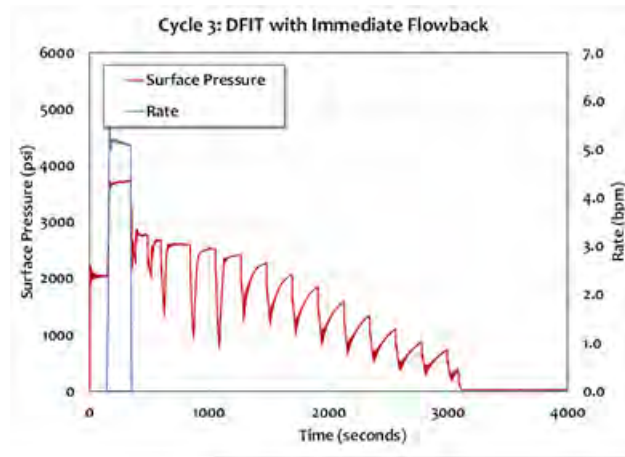


Figure 4. Pump-in/flowback test in well 16A(78)-32.

Therefore, the methods associated with flowback tests and temperature signatures are not only an essential supplement to conventional methods, but also provide a valuable perspective of the in-situ stress measurements.

The inferred closure stresses/minimum in-situ stresses for Utah FORGE are summarized in Table 1. For well 58-32, the conventional methods yield a wide range of closure stresses. This range of stresses could reflect poroelastic effects from the pressurization of natural fractures and/or different injected volumes. The results from flowback methods are at the lower bound of those inferred from conventional methods for well 58-32. The temperature-based interpretations yield similar results to the conventional methods in the same injection zone. Overall, the results from well 16A(78)-32 display a narrower range, with the conventional and flowback methods giving consistent results.

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Table 1. Summary of inferred closure stresses/minimum in-situ stresses at Utah FORGE site

Well	Method		
	Conventional Methods	Methods with Flowback Tests	Methods with Bottom-hole Temperature
58-32	15.2 – 21.5 MPa/km 0.67 – 0.95 psi/ft	14.3 – 14.9 MPa/km 0.63 – 0.66 psi/ft	14.9 – 17.9 MPa/km 0.66 – 0.79 psi/ft
16A(78)-32	16.3 – 17.0 MPa/km 0.72 – 0.75 psi/ft	16.1 – 16.5 MPa/km 0.71 – 0.73 psi/ft	N/A

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Successful Implementation of HT Geothermal Drilling Technology

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Introduction

The Olkaria geothermal field is located within the Kenya Rift Valley, 120 km from Nairobi. The Olkaria structure is an open uplift of volcanic eruptive rock deposits. At the surface, the uplift is about 42km long and 28km wide, and the depth of the target layer is 2000-2540m. In the drilling process, there are technical problems such as high underground temperature (up to 350°C), hard

and abrasive formation, severe loss of circulation, low bit service life and ROP, corrosive fluid, drill pipe corrosion and so on.

But as can be seen from the well temperature profile curve in Figure 1, the block has good geothermal development value. The first section is from the wellhead to the 850m section, and the wellbore temperature rises sharply to 282°C. The second is the 3300-3570m well section, where the temperature increases rapidly from 328°C to 390°C.

A total of 147 geothermal wells have successfully been drilled since 2007. The successful implementation of integrated HT geothermal drilling technology indicated not only the enhanced well productivity but also the great success in overcoming the severe loss of circulation and the HT drilling problems encountered while drilling. These integrated technologies include: a) aqueous foam geothermal drilling technology; b) the directional and cluster wells drilling technology by a single shot tool; c) flushing and backfilling cementing technology; d) tailor made HT PDC drill bits.

Aqueous foam geothermal drilling technology

While drilling in the Olkaria geothermal field, rocks encountered in the historical wells include pyroclastics, rhyolite, tuff, trachyte and basalt. We can identify that the lost circulation mainly resulted from the fractured zone and lower hydrostatic pressure formation. Aqueous foam drilling was used to solve the circulation problem. Based on these characteristics, it is

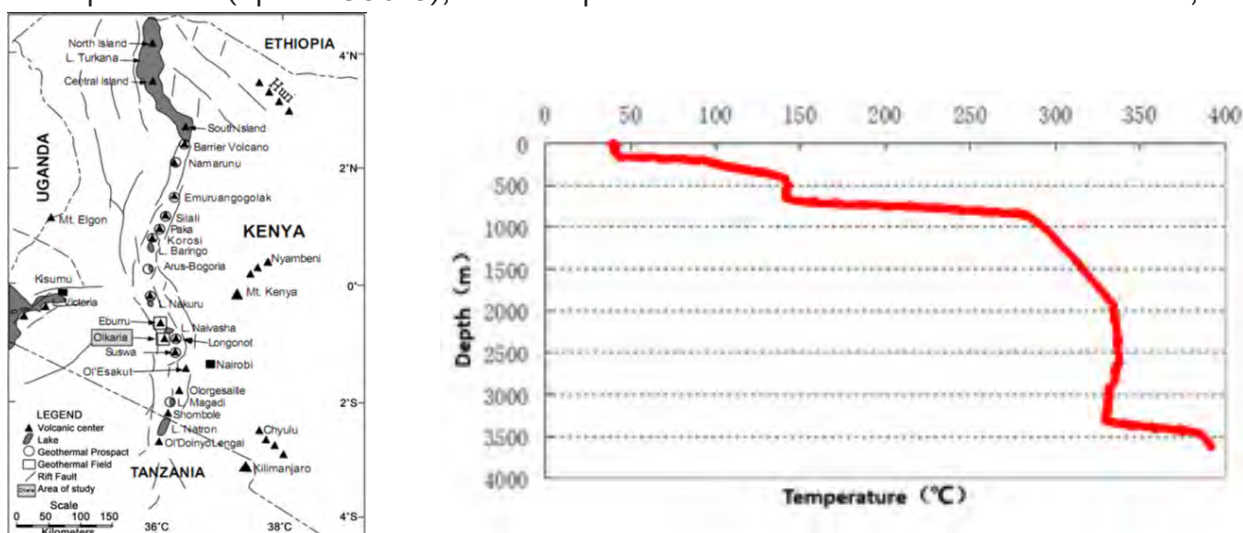


Figure 1. Distribution of geothermal resources in Kenya and the well temperature profile curve.

important to avoid higher circulation pressure caused by improper gas-liquid flow, define proper flow parameters, adjust circulation parameters together with observation of torque, cuttings settlement and return temperature.

Aqueous foam drilling also has other advantages. It is difficult and expensive to deal with the settling cuttings due to the longer open hole and small annular spaces. So it is important to clear the hole by circulating with aqueous foam. Another function of aqueous foam is to cool the hole. While drilling into live production zones, the hole is producing both steam and water and the temperature of return fluid will rise up gradually; aqueous foam can act as a coolant.

Directional and cluster wells drilling by single shot tool

The method of the directional and cluster wells used in the oil industry was used for development of geothermal resources in Olkaria. Some special orientation methods are put into practice due to lost circulation and upper heterogeneous rock. The single shot tool was used for directional geothermal drilling because it has a higher temperature resistance than the MWD and its cables, and it is also more efficient in carrying out the downhole survey operations. Due to heterogeneous geothermal formation, hard and abrasive rock should be drilled out with a rotary table. In order to decrease dog legs, less than 0.75° single bent screw drills were used. Use of an under gauge stabilizer during a hold angle interval reduces the risk of pipe stuck. By using these technologies some wells reached the record output of 16 Mwe.

Flushing and backfilling cementing technology

Due to the severe circulation losses in the geothermal formations, the cement slurry mostly could not return to the surface as with a conventional cementing job. In geothermal wells, it is critical that no water is trapped between any two casings otherwise the casings will fail during discharge after the well heats up. To avoid trapping of water and attaining a good cement bond, the casing to casing annulus was flushed with precalculated volumes of water. Subsequently, the annulus was backfilled with cement slurry and ensuring no water flows through the backfill in between the jobs. This cement slurry backfilling technology was a great success.

Tailor made HT PDC drill bits

The main problem in the initial wells drilled in 2007 was that the Tri-cone roller bit had low average bit footage and penetration rate including high friction torque. On average, the 8-1/2" hole section is normally within 1800-2200 meters long in Olkaria geothermal wells and it takes almost half of the drilling cycle. The type of bits initially used was not fit for the geothermal abrasive volcanic formations. The bits failed prematurely due to poor bearing seals and excessive bearing clearance. Consequently, the average bit footage and rate were very low. These problems were improved later by using the Polycrystalline Diamond Compact (PDC) bits with journal bearing and gauge protection, so then the average bit footage and rate and service life were increased substantially.

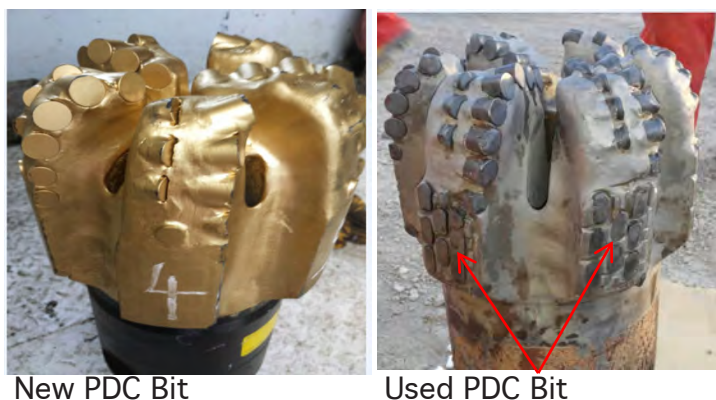
The Tri-cone roller bit's cutting action is provided by rotation of the cones, while the inserts cut/grind on the rock and use jet nozzles to clean the cutters. But the hard formation of Olkaria geothermal field leads to a low rate of penetration, tooth breakage and bit gauge reduction. The high temperature of the well leads to bearing failure. Data from 30 wells were collected and 210 bits were used, with an average of seven bits per well. The average length of footage per bit was 280 m, and each well was drilled in 64 days.

The Polycrystalline Diamond Compact (PDC) bits cutters are made of diamond. The main advantage is that they can adapt to the higher abrasive, hard geological formation, and have better cutting performance. And the cutters thrive well in hard formations and high temperatures, helped by jet nozzles that aid in removing cuttings. Compared with Tri-cone roller bit, the PDC bit has a high rate of penetration (Figure 3.), minimal tooth break (Figure 2.) and there are no bearing failures in high temperature formations.

In addition to using PDC bits, application of a roller reamer can avoid early bit failure. Compared to the sliding friction of a stabilizer, the roller reamer has a function to cut the formation and enlarge the hole to the desirable size with small and steady torque, thus increasing bit life by reducing torque and stress fluctuations.

Table 1. 8½" PDC Bits Performance

Well	Drilling Days	8½" Great Wall Bit	Serial No.	Footage (m)
OW-925	31	GW-506	1619339	3099
OW-734B	43	GW-605	1619413	2755
OW-901B	44	GW-605	1619340	2117
OW-926A	43	GW-506	1619416	2374



New PDC Bit

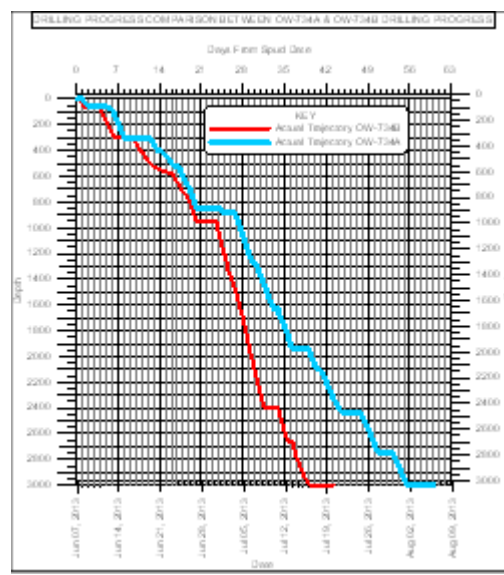
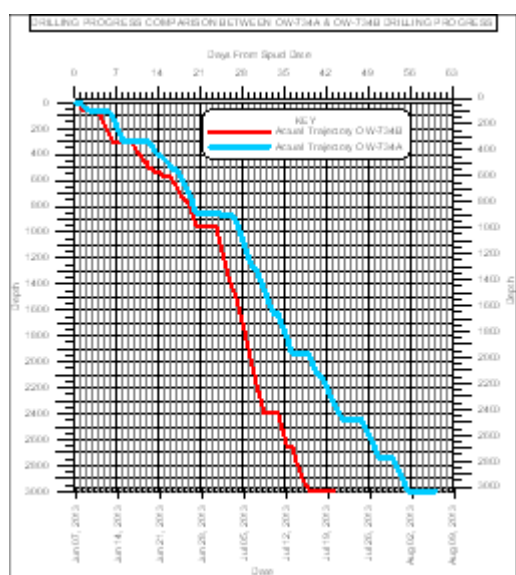
Used PDC Bit

Figure 2. Comparison of PDC bits before and after drilling

Conclusion

With the application of various technologies, the deep formation has greater development potential. Compared with the high development cost and uncertainty of fracturing technology, ultra-deep drilling technology provides another development option which is beneficial to release formation potential. The breakthrough use of

tailor made HT PDC drill bits is the foundation of this technology. The Olkaria geothermal field used this bit to increase the well depth from 3,000 m to 3,650 m, with double the power generation. And the tailor made PDC bits reduced the drilling days from 64 to an average of 40 days per well. It is also important to state that out of all the 147 wells allocated to GWDC, none was lost and they were all completed to the target depths. The tailor made PDC bits technology proved to be a solution in reducing drilling downtime and consequently drilling costs. It should be recommended for application in drilling wells especially within the entire East African Rift system. It would facilitate acceleration of geothermal resources development for green energy.



OW-734B – 43 days OW-734A – 61 days OW-901B – 44 days OW-901A – 64 days

Figure 3. Comparison of the drilling time

ORCHYD: A Fluid-driven Drilling System Combining Water Jetting and Hammer Drilling for Cheaper Geothermal Drilling

Submitted by ORCHYD Team: Scientific Coordinators: Laurent Gerbaud, Hedi Sellami (ARMINES/ MINES Paris). Project Partners & Technical Leaders: John-Paul Latham (Imperial College London), Alexandre Kane (SINTEF), Florian Cazenave (Drillstar Industries), John Paravantis (University of Piraeus Research Center), Hualin Liao (China University of Petroleum). Scientific & Technical Manager: Naveen Velmurugan (ARMINES/ MINES Paris).

Geothermal energy harnesses the heat of underground rocks to convert water to steam to supply uninterrupted power as opposed to wind and solar energy sources. This makes geothermal energy a leading candidate for a carbon neutral, efficient and reliable source of renewable energy supply across the globe. However, the current drilling methods to reach the rocks at a depth of more than 4 km are slow and inefficient – making geothermal sources supply less than 2% of the global energy mix.

Nearly 50% of the capital costs in geothermal energy exploitation is contributed by the drilling – a showstopper in scaling this non-intermittent sustainable energy resource. The ORCHYD project, abbreviated from Novel Drilling Technology Combining Hydro-jet and Percussion for ROP Improvement in Deep Geothermal Drilling, is set up to combine high pressure water jet and a high-power mud downhole hammer drilling system with a goal to at least double the rate of penetration (ROP) in hard rocks, compared to conventional drilling methods. The envisioned approach aims at reducing the drilling costs by upward of 65%, making the utilization of geothermal energy cheaper and more widely available – a facilitator in the energy transition to tackle the global climate crisis.

The ORCHYD project commenced in January 2021, with a total budget of 4 million euros funded by the European Commission under the Horizon 2020 program for a period of 3 years. The project is led by researchers at the Centre of Geosciences, ARMINES/ MINES Paris (France), and

the consortium includes Imperial College London (UK), SINTEF (Norway), Drillstar Industries (France), University of Piraeus Research Center (Greece), and China University of Petroleum (East China).

Project leader ARMINES/ MINES Paris will utilize their experimental facilities to test the new drilling approach and will demonstrate a new concept of rock breaking mechanism used in the project (A facility to study vertical drilling under deep bottomhole conditions and rock stresses is shown in Figure 1). The experimental data collected will be utilized by the partners – mainly Imperial College London (ICL), SINTEF, and ARMINES/ MINES Paris – to calibrate the various numerical models used to optimize the cutting and jetting processes of hard rocks at great depths under downhole conditions. The physical parameters are then assessed to achieve the projected multifold increase in the drilling penetration speed. The downhole pressure intensification process for jetting is investigated by China University of Petroleum (East China). The industrial partner of the project, Drillstar Industries, bridges the gap between the industry and academia, by providing relevant information about the real time drilling process and by manufacturing and testing the prototypes that will be developed. A key segment overseeing the impact of geothermal energy on the environment, energy security and geopolitics, and in society overall, is carried out by the University of Piraeus Research Centre (UPRC). A continuous feedback loop setup in the consortium between theoretical and experimental work; academia and industry, is one of the major



Figure 1. An experimental setup of ARMINES for vertical drilling, Pau.

strengths of the project.

The final objective of the ORCHYD project is to develop a prototype that combines a high-pressure water jet (HPWJ) system with a down-the-hole (DTH) hammer -- that is fully fluid (mud) driven. The targeted rock types are hard crystalline rocks such as granite, that are usually found at greater depths (>4 kms) and are subject to a high stress regime. We aim to exploit a new concept called 'Self-Relief Drilling (SRD)' highlighted and patented by ARMINES/MINES Paris to achieve the envisioned increase in the drilling efficiency. SRD is a method to reduce the mean stress of the rock in the immediate vicinity of the drilling bit action, thus having the potential to generate tensile stresses and facilitate the drilling and jetting process. SRD is achieved by creating a specific profile of the bottomhole – an example of comparison between the radial stress distribution achieved in the conventional and SRD operations is shown in Figure 2. In addition, reflections of the compressive waves against the rock profile boundaries are taken advantage of during the percussive drilling action – increasing the ROP.

To set up the novel drilling technology, we integrate the systems that transfer hydraulic energy from the surface to the downhole environment, to create the peripheral grooves and then, break the weakened rock. To achieve this, four technical segments are investigated in this project:

A HPWJ system that can deliver fluids at a pressure of 250 MPa to create the grooves necessary to make use of the SRD concept. A variety of nozzles and their jetting action on the

candidate rocks are simulated by ICL and tested.

A Pressure Intensifier that can pressurize the fluid in the downhole environment will be used. The intensifier considered for the project, developed by UPC, principally works on converting the mechanical energy generated by drilling vibrations into hydraulics that can feed the high-pressure fluid to the nozzle of the HPWJ system.

A DTH Mud Hammer developed by Drillstar is used to drill through the rock. The mud hammer under investigation is fully fluid-driven as well.

Lastly, an innovative Drill Bit is designed to optimize the percussive cutting process that can take full advantage of the new bottomhole configuration.

The fundamental innovation of the project lies both in the development of a new principle to 'free' the deep rock from the existing concentrated stress in the immediate vicinity of the drill bit, allowing for an easier rock-cutting action, and the reflection of the impact waves on the slots cut by the high-pressure water jet. An example of a hard granite rock sample (UCS of 200 MPa) slotted with a 200 MPa HPWJ under a 14 MPa back pressure is shown in Figure 3. A schematic bottom hole assembly (BHA) of the new drilling technology that investigates the combination of two separately mature technologies – water jetting and hammer drilling – is shown in Figure 4.

To optimize this new drilling technology, multiple developments are carried out in parallel that

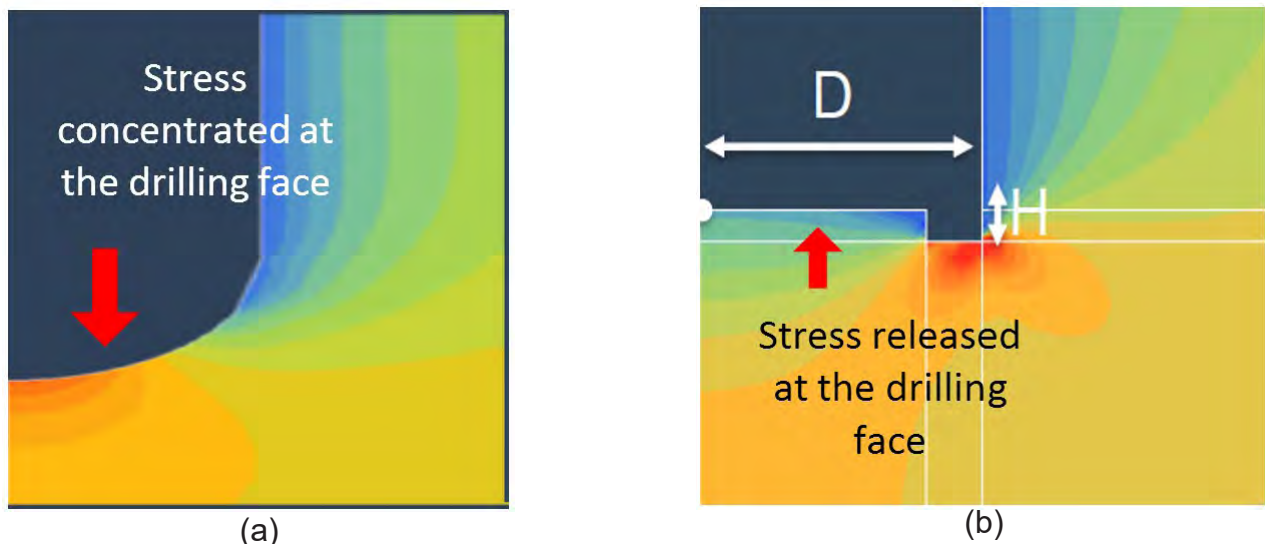


Figure 2. (a) Radial stress distribution – conventional bottomhole profile; (b) Radial stress distribution – modified bottomhole configuration including peripheral grooves. (Low stress indicated in blue and high by red.)



Figure 3. Example of a slotted Sidobre granite rock specimen.

include numerical investigation of the rock breakage process itself at a micro- and meso-scale due to the ultra-high pressure jets under bottomhole conditions, whose efforts are led by ICL; numerical simulations of the bit-rock interaction, induced drilling dynamics, designing drilling fluids using engineered nano-particles to reduce the frictional properties while being functional to the drilling process, whose efforts are led by SINTEF; conducting surveys, studying the social acceptance and impacts on different spheres of our ecosystem, for innovative technologies in developing energy resources, whose efforts are led by the University of Piraeus Research Centre.

Acknowledgment

This project has received funding from the European Union's Horizon 2020 research and innovation programme under grant agreement No 101006752.

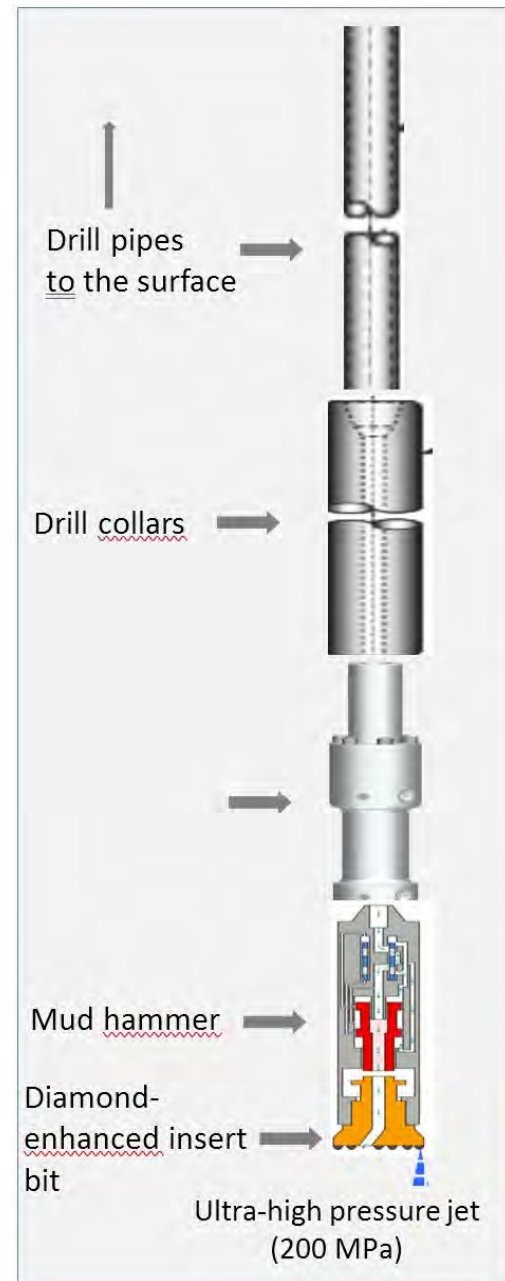


Figure 4. A schematic of the BHA of the envisioned novel drilling technology containing a pressure intensifier, DTH mud hammer and a modified drill bit.