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Drilling for Superhot Geothermal Energy:

A Technology Gap Analysis

Rebecca Pearce, Cascade Institute,
Tony Pink, Pink Granite Consulting

Authors:

Dr. Rebecca Pearce is a Fellow on the Energy Systems team and the Ultradeep Geothermal Science Lead at the Cascade Institute. Her research focuses on geothermal site characterization and emerging geothermal and drilling technologies. Rebecca is an expert in applied magnetotellurics and has contributed to projects in Northern British Columbia, Chile, and West Antarctica. She holds a PhD in Geophysics from University College London.

Tony Pink is the Owner/Director of Pink Granite Consulting LLC and was recently appointed the Task Force Chairman for Drilling Technology for the US Department of Energy GEODE project. He has 34 years of drilling experience in oil and gas and geothermal. Before starting his own business, he was VP of Subsurface Technology for NOV focusing on the development of tools and equipment for the geothermal industry. Tony has a BSc in Geology from UCW Aberystwyth and a postgraduate diploma from Harvard Business School. He has five patents (two granted and three pending).

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Summary

The research frontier of drilling and well construction for superhot rock (SHR) geothermal energy systems—the production of renewable, baseload electricity by circulating water in deep (>5 km), hot (>374˚C) rock—is steadily advancing. Recent achievements in polycrystalline diamond carbide (PDC) drill bit design, improved rates of penetration (ROP) into hard rock, and the development of insulated drill pipe show that deep drilling for SHR geothermal projects is on the not-distant horizon.

But several key technology gaps still stand in the way of deep drilling in hostile subsurface geological environments. Technology companies and laboratories must make rapid advances in specialized drilling rigs, bit technology, high-temperature downhole tools, and temperature management equipment. Currently, these drilling systems—and the amount of time required to access deep, hard rock formations—create significant project costs. To bring SHR geothermal to commercial viability, technology companies and laboratories must rapidly develop, test, and deploy new technologies.

This report reviews state-of-the-art deep geothermal drilling and well-construction technologies, identifies existing technology gaps, and suggests strategies to overcome these gaps. Each technology is given a technology readiness level (TRL) between 1-9, from theoretical to commercially scalable.

Overall, we find that SHR geothermal wells can be drilled by deploying a combination of existing technologies and that the technological challenges to SHR drilling are surmountable. The economic challenges are a function of limited availability and testing of these drilling systems, which will decrease as the SHR geothermal industry expands.

A first-order gap shared by these technologies is the lack of access to SHR conditions, both in-field and in controlled laboratory conditions. Without open-access experimental facilities and pilot sites, these technologies cannot undergo iterative improvements necessary to de-risk SHR drilling and propel the industry forward.

Table of Contents

Table of Figures

Acronym glossary

Adjustable kick-off (AKO)
Advanced Research Projects Agency-Energy (ARPA-E)
Bottom hole assembly (BHA)
Bottom hole circulation temperature (BHCT)
Closed-loop geothermal (CLG)
Conical diamond element (CDE)
Conventional drill pipe (CDP)
Depth-of-cut (DOC)
Department of Energy (DOE)
Directional steel shot drilling (DSSD)
Drilling in Deep Super-Critical Ambient of Continental Europe (DESCRAMBLE)
Enhanced geothermal system (EGS)
First-of-its-kind (FOAK)
Finite element analysis (FEA)
Geothermal Anywhere (GA)
German Continental Deep Drilling Programme (KTB)
High electron mobility transistors (HEMTs)
High-temperature, High-pressure (HTHP)
Inner diameter (ID)
Insulated drill pipe (IDP)
Integrated ceramic electronics (ICE)
Iceland Deep Drilling Project (IDDP)
Levelized cost of electricity (LCOE)
Log-while-drilling (LWD)
Mechanical specific energy (MSE)
Measurement-while-drilling (MWD)
Metal-to-metal (M2M)
Millimetre wave (MMW)
Nth-of-its-kind (NOAK)
Non-productive time (NPT)
Oak Ridge National Laboratory (ORNL)
Oil & gas (O&G)
Particle Drilling (PD)
Polycrystalline diamond carbide (PDC)
Positive displacement motor (PDM)
Rate of penetration (ROP)
Rotary steerable system (RSS)
Superhot rock (SHR)
Supercritical carbon dioxide (sCO2)
Technology readiness level (TRL)
Torque on bit (TOB)
Total depth (TD)
True vertical depths (TVD)
Utah Frontier Observatory for Research in Geothermal Energy (FORGE)
Versuchsstollen Hagerbach (VSH)
Water-based mud (WBM)
Weight on bit (WOB)

1. Introduction

The expansion of geothermal heat use for energy production beyond its current tectonic boundaries offers an opportunity to supply carbon-free, renewable, baseload power anywhere in the world. It is estimated that two percent of thermal energy within 3-10 km of the surface may offer the equivalent of 2,000 times the current energy demand in the US and is virtually inexhaustible (Petty et al., 2020; Tester et al., 2006; van Oort et al., 2021).

This vast resource of heat can be extracted through the circulation of water in hot, naturally or artificially fractured, low-permeability rock formations referred to as an Enhanced Geothermal System (EGS), or from a subsurface interconnected closed-loop well network, referred to as Closed-Loop Geothermal (CLG). However, these "next-generation geothermal systems" are not cost-competitive with mature energy technologies. Drilling is the most cost-intensive process of a geothermal project and current drilling systems require further innovation to perform in the hostile geological domains targeted by these projects. Advancing drilling technologies is critical to make next-generation geothermal projects economically and technically feasible.

The ideal application of next-generation geothermal systems is the production of electricity with high-enthalpy (>2,100 kJ/kg) water under supercritical conditions (specifically, >374˚C temperatures and >22 MPa pressures in pure water—Figure 1). Researchers estimate that a levelized cost of electricity (LCOE) of USD 25-45/MWhr can be achieved with an EGS flow rate of 80 L/s from high-enthalpy water, sourced from SHR (Cladouhos & Callahan, 2023). At these conditions, a geothermal plant with a 1 km^2 footprint and a tri-well system consisting of one injector and two producers may sustain an 80-100 MW capacity for the duration of its lifetime (40-80 years) (Petty et al., 2020). This disruptive technology is finally receiving recognition and, within the past few years alone, research programs have rapidly advanced the R&D frontier of SHR technologies.

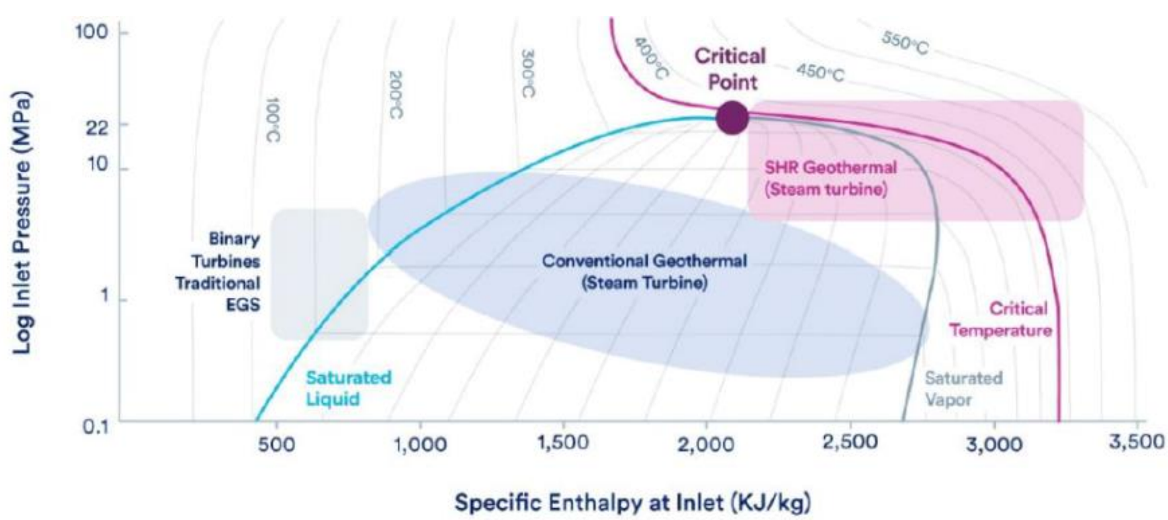

Figure 1 Specific enthalpy of pure water under increasing temperature and regimes

The fluid state and wellhead temperatures required for low-temperature conventional and SHR geothermal plays (Cladouhos & Callahan, 2023)

One of the biggest technical obstacles to achieving scalable, cost-competitive SHR is well construction and completion in lithologies at superhot conditions. The average geothermal gradient in the world is 30˚C/km but can range from 15-20˚C/km in shield-type cratons and subduction zones to 40-100˚C/km in volcanic regions or extensional tectonic regimes. Assuming an average global surface temperature of 15˚C, the typical depth to supercritical temperatures is in the range of 7-10 km beneath the surface into crystalline basement (van Oort et al., 2021). However, the depth range accounting for the global variability in geothermal gradient is 5-20 km.

To successfully construct a geothermal well, an SHR drilling program must overcome **three overarching challenges**:

1. Create deep wells in crystalline basement,
2. Overcome high temperature and high pressure (HTHP) conditions, and
3. Maintain borehole stability and casing integrity for the lifetime of the geothermal plant (>40 years).

Overcoming these challenges will require highly specialized drilling, casing, cementing, and completion equipment, some of which exist today and others that require further research and financial investment (Petty et al., 2020; Thorsteinsson et al., 2008). Industry, along with university and government research labs, are building upon the decades of research conducted by the oil and gas (O&G) industry on the construction of complex, high-temperature, high-pressure wells. Hydraulic fracturing at >5 km depth is not uncommon in the hydrocarbon industry in sedimentary systems, and wells with over 15 km measured depth have been achieved. Wellhead temperatures over 350˚C can be encountered in O&G and some high-temperature well completion equipment exists (van Oort et al., 2021). While these technologies are transferrable to SHR, there are several key differences between an ultradeep SHR geothermal well and a hydrocarbon well:

- SHR wells will reach >374˚C temperatures, whereas hydrocarbon wells typically range from 100-220˚C,
- SHR wells will be constructed in hard, abrasive, impermeable, crystalline rock with compressive strengths of >240 MPa-far greater than soft, sedimentary rocks of <80 MPa normally encountered in hydrocarbon wells,
- SHR wells will require larger production hole sizes to support higher flow rates,
- SHR fracturing may lead to severe losses of drilling fluid and may require wellbore sealing methods in harder rock and higher-temperature conditions than experienced in hydrocarbon wells,
- Drilling and well completion programs for a SHR geothermal project typically account for 40-60 percent of total project costs, and
- Very few geothermal wells are drilled annually relative to hydrocarbon wells, offering less opportunity for iterative design improvements (van Oort et al., 2021) and the performance improvements seen in shale drilling in the U.S.

These key differences, along with the challenges of well construction in supercritical conditions, create **four primary technology gaps** that must be overcome to make SHR technically and economically viable—the first two of which pertain to drilling and well construction:

1. **Improve the ROP when drilling into crystalline basement rock.**
2. **Develop ultra-high-temperature electronic downhole tools and temperature management equipment.**
3. Mitigate circulation loss (this may be less of a problem for SHR than in hydrothermal geothermal settings because locations can be selected to minimize the risk of hitting fracture zones).
4. Create casing and cementation that can withstand the potentially corrosive hot water and high pressure of SHR wells, with larger production-hole sizes to support high flow rates in high-temperature regimes.

To date, the drilling and completion programs for next-generation geothermal projects can account for 40-70 percent of total project capital expenditure costs (van Oort et al., 2021, Song et al. 2023). These costs may substantially increase as deeper, hotter, and higher-pressure regimes are explored. While it is expected that the first-of-a-kind (FOAK) demonstration sites will incur high upfront costs required to de-risk SHR through experimentation, Nth-of-a-kind (NOAK) plants may achieve a cost-competitive LCOE as a result of the high energy per well delivered to the surface by superhot steam and supercritical fluids, unleashing this vast reserve of energy for sustainable power production.

This report investigates state-of-the-art drilling technologies striving for SHR temperatures by drilling ultradeep (>5 km) wells through hard rock lithologies. The sections cover rock-destroying technologies, high-temperature electronic tools, and temperature management equipment. Each review defines the TRL status of each technology within each category, the technology gaps between their current capacity and the needs of SHR, and strategies to overcome these gaps. The analysis in this report was conducted through an extensive literature review, dozens of interviews with experts across the industry, and decades-long experience by the lead author of this study.

Section 2 begins by closely examining the overarching challenges for SHR identified above and describes the landscape of next-generation experimental and pilot sites laying the foundation for further SHR research. Section 3 defines the requirements of an SHR well, including the drilling system, MWD and downhole sensors, top-side equipment, drill string, and mud cooler requirements. Sections 4-7 review state-of-the-art rock-destroying equipment (including subsets of conventional, hybrid, and novel direct energy drilling methods), high-temperature electronic tools, downhole temperature management equipment, and corrosion inhibition technology. These sections identify key gaps for SHR and strategies to address them.

2. Background

2.1 Drilling challenges

To reach SHR, a geothermal system must contend with hard crystalline basement rock, unprecedented depths (from 5-15 km below the surface), and temperatures of >374˚C superseding the pressure-temperature capabilities of most conventional drill bits (Naganawa 2017). In the case of conventional drilling, the casing and cementation process is a major challenge in these conditions due to the extreme depths that require a larger hole diameter, and the risk of casing/cement failure due to high temperatures and corrosive substances downhole, which could potentially lead to partial borehole collapse, steam and brine leakage, and severe damage to the installed equipment.

To accommodate these conditions, specialized borehole designs and temperature-rated cement and casing materials are required to maintain well integrity, leading to significant costs (Petty et al., 2020; Thorsteinsson et al., 2008). Downhole electronics, such as directional tools and measurement-while-drilling (MWD) tools, are rarely rated above 200˚C (see Section 5). Lastly, in SHR conditions of >374˚C, rock may exhibit ductile behaviour and will not fail under the rock-crushing mechanisms used by conventional drilling (Naganawa 2017). Corrosion is probably less of a concern in SHR next-generation systems than hydrothermal systems, but the elevated temperatures will still have implications for corrosion inhibition.

Several EGS and conventional geothermal projects have experienced complications due to the limitations of conventional drilling and well-construction methods. While these are not SHR projects, they experienced similar challenges to those stated above. Compromised well integrity has led to failed stimulation tests at Reykjanes (Iceland), Newberry (Oregon), Sumikawa (Japan) and Beowawe (Nevada) sites (in 2017, 2012, 1989, and 1983 respectively), where stimulation fluids leaked through damaged or perforated casing. Fluid leakage can occur due to thermal contraction from heating and cooling cycles during stimulation, or from cave-ins in deviated or horizontal sections.

High pressures have led to the loss of equipment downhole, such as in the Cooper Basin (Australia) in 2009, where a drill string was stuck at 3,700 m depth due to the pressure differentials between an over-pressured fracture and the wellbore. The continued accumulation of mud and cuttings further prevented its recovery and the project was terminated. Similar “differential-sticking” incidents occurred at The Geysers (California), Soultz-sous-Forêts (France), Basel (Switzerland), Bad Urach (Germany), Soda Lake (Nevada), and Coso (California) geothermal sites, some of which were ultimately abandoned due to this issue (Pollack, Horne, and Mukerji, 2020).

Over-pressure can also lead to kicks (sudden increases in well pressure) and blowouts, which were repeatedly experienced in the Cooper Basin (*Ibid.*). Conversely, low-pressure, permeable formations that can be found in geothermal domains, such as fractured rhyolites, granites, or volcanic tuffs, commonly lead to circulation loss of high-pressure drilling fluid. Circulation loss can be mitigated by cement plugs and fluid influx control; however, these strategies can incur costly drilling delays, even up to 10 percent of the drilling program costs (Denninger et al., 2015). At the Utah Frontier Observatory of Research for Geothermal Energy (FORGE), Fenton Hill (New

Mexico), Bad Urach, and Soultz-sous-Forêts, zonal isolation equipment (specifically, packers) was prone to rupture in high-temperature environments, which led to leakage and compromised well stimulation (Pollack, Horne, and Mukerji, 2020).

Although these same challenges were mostly encountered at EGS and conventional geothermal projects,[1] these complications are also expected for SHR drilling. Several SHR boreholes have been drilled to date; however, no SHR well has reached commercial operability. Historical SHR projects, such as the Drilling in Deep Super-Critical Ambient of Continental Europe (DESCRAMBLE) project (Italy), are groundbreaking examples of the potential of mechanical drilling technologies to access SHR conditions. However, the drilling technologies used in historical SHR sites are no longer up to date. Therefore, a review of current EGS pilot sites provides a more complete understanding of the technology frontier of SHR drilling.

2.2 Frontier pilot sites

Several recently completed and ongoing EGS pilot sites have made significant strides to advance the research frontier of well construction in hot, hard rock (some in SHR conditions). Projects with relevant learnings include: the US Department of Energy (DOE)-funded Utah FORGE, the commercial venture Fervo Energy(USA), the Iceland Deep Drilling Project, and the St1 Deep Heat Project (Finland). Although there are other important sites, these four projects were reviewed because of their timeline (recent drilling technologies were deployed), as well as their relevant learnings for drilling in SHR.[2]

Utah's Frontier for Research in Geothermal Energy (FORGE)

The wells drilled at the DOE-funded Utah FORGE project have been instrumental in improving conventional drilling technologies for drilling into high-temperature impermeable lithologies up to 240˚C. The objective for Utah FORGE is to push the frontier on hard rock drilling and reservoir creation for next-generation geothermal projects. While not specifically pursuing SHR conditions, their achievements in ROP generation are directly transferrable to SHR projects, as efficient drilling is essential to improving the economic feasibility of SHR. To date, 6 wells (Figure 2) have been drilled, each demonstrating iterative improvements in ROP and bit-life that demonstrate the potential of conventional drilling methods for SHR projects.

[1] Please refer to Reinsch et al. (2017) for a thorough review of SHR drilling challenges encountered at Lardarello (Italy), Krafla (Iceland), Kakkonda (Japan), the Geysers (USA), Los Humeros (Mexico) and Menengai (Kenya).

[2] Please refer to Bromley et al., 2020 (and the references therein) for a description of DEEPEGS, Kakkonda, GEMex, and The Geysers, that have all reached conditions >374˚C.

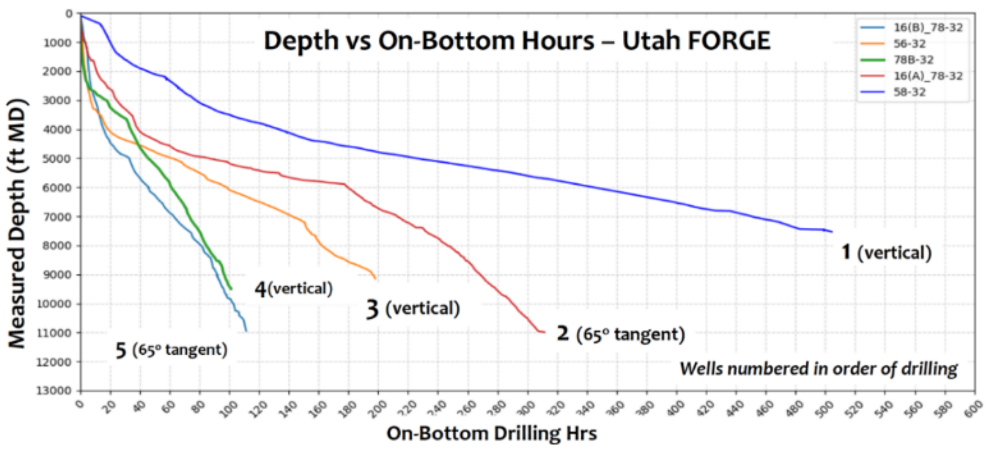

Figure 2 Depth versus on-bottom drilling hours for the wells drilled at Utah FORGE as of 2023 (Noynaert, GRC 2023)

Based on interviews with the project's managing principal investigators, tests at FORGE revealed that drilling into hotter, higher-pressure regimes such as SHR would require better systems for downhole management, including the management of Mechanical Specific Energy (MSE) and vibrational dysfunction, better downhole sensing and drilling automation, and improved rotary steerable systems. SHR drilling needs further advances in bit design and MSE management to overcome interfacial severity from heterogeneous, interbedded formations, such as acoustic and sonic techniques used in hydrocarbon exploration. Vibrational dysfunction is also a concern that requires further innovation of topside equipment. "Look-ahead" technologies that locate potential blowouts (such as from severely fractured lithologies) would allow the adjustment of parameters before hitting fractured domains.

Automated drilling may be a solution for bit dysfunction management. For example, FORGE saw performance improvements with the Nabors REVit® ZT automation program for downhole torque management. Meanwhile, technologies like Thrubit™ logging, vibrational management, and ultrasonic imaging could be used for fracture mapping. Rotary steerable systems for directional drilling have great potential but must be adapted for the harsh environment of SHR. Next-generation drilling should also be applied in other geological settings, including hotter, impermeable domains such as the Salton Sea, Coso, and the eastern US.

Almost all the equipment and methods used at FORGE can be used to drill over 300˚C, but the main limitation is the temperature ratings of downhole sensing equipment.

Fervo Energy (Blue Mountain, Nevada; Cape Station, Utah)

Fervo Energy is not yet in pursuit of SHR; however, their learnings around ROP generation and the challenges from their drilling programs are highly relevant for future SHR projects. In 2023, Fervo achieved major improvements in ROP at its site in Cape Station, Utah. At the time of publication, Fervo has drilled two horizontal wells in Nevada and six in Utah. The wells were drilled from 2022-2024 to approximately 4 km measured depth, with 900 m lateral sections (Figure 3).

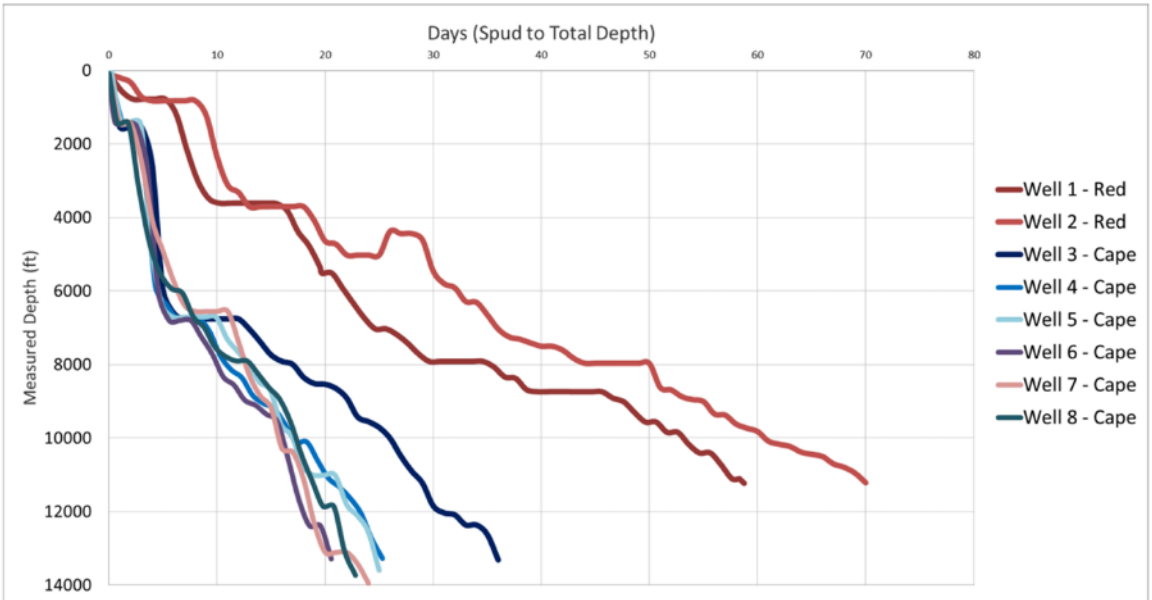

Figure 3 Total depth drilling times for the 8 wells at the Cape Station site in Utah (El-Sadi et al., 2024)

Drilling fluid temperatures were monitored throughout the drilling operation in mud pits and through MWD. The maximum temperature downhole was 107˚C, significantly lower than the static reservoir temperature of 109-210˚C, with no MWD or directional tool failures (Fercho et al., 2024). In the context of SHR, these results indicate that cooling the borehole while drilling is a worthwhile approach for MWD and LWD procedures and should be adopted for future projects in hotter regimes. In an interview with Fervo engineers, they identified three main gaps for SHR:

- Friction in the lateral wells may lead to accelerated bit wear and energy losses;
- While drilling to <450˚C is not a major concern, downhole chemistry (see Section 7) and high-temperature drilling tools require further innovation; and
- ROP generation will likely reach a limit once wells can be drilled in 10 days, at which point drilling is not a major cost factor (however, Fervo's wells are shallow and cool relative to SHR wells).

Iceland Deep-Drilling Project (Krafla and Reykjanes, Iceland)

The Iceland Deep-Drilling Project (IDDP) is a component of the DEEPEGS initiative and is funded by HS Orka, Landsvirkjun, Reykjavik Energy, the National Energy Authority of Iceland, Alcoa, Equinor, and the EU Horizon 2020 program. Their first well (drilled in 2009 at Krafla, IDDP-1) was intended to be 4,500 m but encountered molten lava at 2,100 m, which produced steam at 452˚C and made it the hottest production well on record. Completed in 2015, it was drilled with 177 - 288˚C temperature-rated tricone bits, a conventional motor, and high-temperature metal-face seals (Friðleifsson et al., 2019). The well was ultimately decommissioned due to high levels of corrosion and abrasion of the downhole equipment (Petty et al., 2020). IDDP-1 could have been the world's first magmasourced EGS system, however, persistent valve failures resulted in the closure of the well. Further innovation of wellhead systems to cope with high pressures are needed for SHR.

The second well (IDDP-2) was drilled at Reykjanes in 2016 by extending an existing conventional well from 2,500 m to 4,659 m (MD) with a 30° tangent starting at 2,750 m and reaching bottom hole temperatures of 426˚C and 340 bar pressure—truly supercritical for both fresh and saline water. There were substantial circulation losses below 3.2 km to the final depth and the MWD temperature sensor was placed 14 m above the bit (Friðleifsson et al., 2019; Stefánsson et al., 2018). The estimated true temperature was closer to 540˚C (Petty et al. 2020).

The demonstration well IDDP-2 proved an exceptional resource of geothermal energy, increasing the productivity of the existing site by 40-50 percent. IDDP primarily used high-temperature roller cones and one hybrid PDC/roller cone (further discussed in Section 4.1). The geothermal field was artificially stimulated at much greater depths and temperatures than the existing conventional well using specialized drill bits and BHA technologies (Friðleifsson et al., 2019). This first-of-its-kind geothermal well is a major achievement for the development of supercritical geothermal resources. Runs 12 and 13 included a pioneering metal-on-metal motor designed and built by Baker Hughes.

While IDDP-2 was a groundbreaking accomplishment in SHR drilling, circulation losses proved to be a serious complication. Pumping water through the drill string is essential to maintain manageable bottom-hole temperatures, requiring 40-60 L/s. Water must also be pumped into the annulus to cool the casing. Losses started at 3.2 km to the final depth, after which point new water resources had to be continuously pumped, resulting in the consumption of 1.5-2 million tons of fresh water throughout the 168-day drilling operation. Cement plugs were attempted to heal loss zones up to 3.2 km, but they were unsuccessful, and this solution was abandoned (Friðleifsson et al., 2019). Interestingly, the successful drilling of this well and the management of the bottom hole temperature may have been aided by the total losses. Above the total loss zone, the pipe would have been insulated from the formation temperature by the empty annulus. The IDDP-2's circulation loss issues highlight an important challenge for SHR.

St1 Deep Heat Project (Otaniemi, Finland)

The St1 Deep Heat Project is an EGS-type direct heat project located beside an urban power plant in Otaniemi, Finland (a district of Espoo), located 5 km from downtown Helsinki. The project aimed to reach a depth of 5-6 km and supply 20-40 MW_{th} of district heat to the city of Espoo from 100˚C fluid sourced from a stimulated fracture network, re-injecting the fluid at 50˚C through an EGS doublet. While this is not analogous to an SHR project, this case study provides rare insight into drilling to >6 km through hard rock, which will be required for most SHR projects.

Initiated in 2014, St1 completed three wells in the Fenno-Scandinavian Shield by 2023. The pilot well (OTN-1) penetrated 2 km, the seismic monitoring well (OTN-2) penetrated 6.2 km, and the stimulation well (OTN-3) penetrated 6.4 km measured depth, with some tangential drilling for reservoir creation, making it the world's deepest industrial geothermal project to date. After creating the fracture network, OTN-3 underwent a 49-day stimulation test that was temporarily successful despite considerable wellbore failure that required variations in 100-200 m long packer-sealed sections.

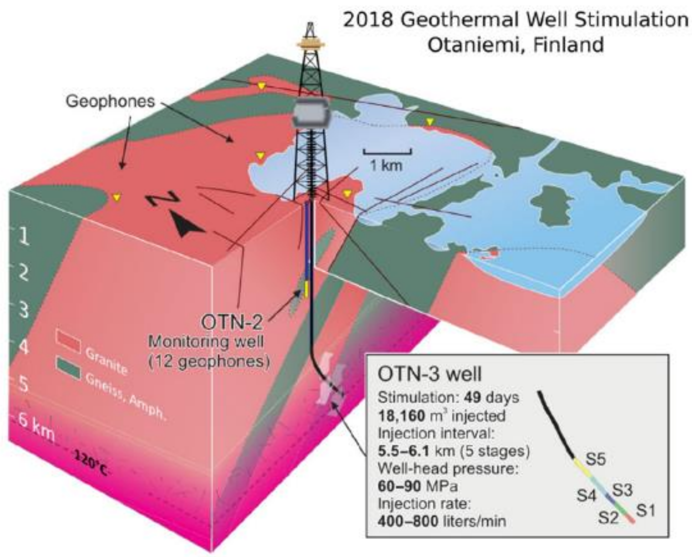

Figure 4 Geological diagram of the Otaniemi EGS site in Finland, including well location, depth, and 120˚C temperature horizon. (I. T. Kukkonen et al., 2023a)

The geology of this area is complex, with cold granite rock, interbedded formations, and a geothermal gradient of 15-17˚C/km (I. Kukkonen & Pentti, 2021). The project's drilling success proves the feasibility of drilling into hard rock formations to unprecedented depths. Strada Global used air hammer drilling methods for sections of the three wells (Figure 4), successfully drilling to 4,520 m for 72 on-bottom drilling days—the world record for drilling depth into hard granite. However, drilling operations consumed 20,000 L of fuel per day. For the deepest well (OTN-3), air hammer drilling was used from 300-3,300 m, followed by rotary drilling to reach 6,400 m (including a deviation). The project experienced wellbore failure during the hydraulic stages, and a series of packers from PackerPlus[R] were deployed at varying intervals to support the wells (Kukkonen et al., 2023b).

Like IDDP, Stn-1 also experienced casing failure at depth and fluid losses but with a significantly colder lithology than IDDP. These common challenges indicate that the risk of circulation losses and borehole collapse likely apply to most geological environments. While the Stn-1 project proves the potential of existing drilling techniques to reach these depths, sustaining reservoir fractures at this depth remains an unsolved challenge. At ST1, the failure to sustain the fractures at depth led to the eventual closure of their project (Kukkonen et al., 2023a).

Conclusions

The experiences of these frontier pilot sites indicate that existing drilling technologies are capable of:

1. Drilling to supercritical conditions >374˚C,
2. Drilling to >6 km through hard rock, the depths most SHR regimes are found, and
3. Rapid increases in ROP through hard rock, cutting back drilling time by >50 percent.

These achievements are encouraging for SHR yet indicate that further engineering iteration is required to make SHR geothermal projects technically and economically feasible. No single project has demonstrated enhanced ROP into SHR through >4 km of hard rock. Further technology gaps may be discovered if the drilling challenges experienced by recent projects are overcome; therefore, further in-field testing at sites with similar characteristics is needed.

The key technology gaps are:

- Failure of downhole tools due to high temperatures, leading to inaccurate LWD or MWD,
- Failure of casing in corrosive or high-temperature environments, leading to borehole failure and collapse,
- Risk of blowouts due to high-pressure, high-temperature working fluids, and
- Circulation losses due to porous or fractured media.

Lastly, the Utah FORGE and Fervo projects have demonstrated impressive ROP (>25 m/hr) through hard rock using specialized drilling technologies. However, Figures 2 and 3 indicate that the drilling performance is approaching a mechanical limit, where improved drilling practices yield the same drilling rates as previous wells. As the wells extend deeper to reach SHR in locations, this limit could affect the economic viability of SHR drilling. This limit may be overcome with further innovation in drill bit technology.

3. Drilling system requirements for SHR

To handle the supercritical conditions of SHR (temperatures >374°C and pressures >22 MPa), a drilling system requires additional capabilities in the following technology domains:

- Rock-destroying equipment,
- High-temperature downhole tools,
- Temperature management equipment, casing, cement, and corrosion inhibition, and
- Topside equipment.

3.1 Requirements for rock-destroying equipment

Most SHR wells will be drilled through igneous and metamorphic rock with high compressive strength. The bit or rock-destroying technology needs to deliver an ROP that is fast enough to make the well economically viable. If the system uses conventional drill bits, roller cones, or PDC bits, the system needs to be designed so that the weight on bit (WOB) and torque on bit (TOB) can be delivered to the cutter-rock interface at substantial depths (>5 km) without suffering vibrational founder or high friction. If an alternative drilling methodology is selected, such as percussive, waterjet, thermal spallation, millimetre wave (MMW), or plasma direct-energy drilling, then the surface system/rig needs to be designed to deliver the energy necessary to fail the rock. Section 4 provides a thorough analysis of state-of-the-art conventional, hybrid conventional, and direct-energy drilling methods, assesses their TRL status, and provides innovative pathways to overcoming remaining technology gaps for SHR drilling.

3.2 Requirements for high-temperature downhole tools

The bottom hole assembly (BHA) for an SHR drilling system must include downhole sensors to collect MWD and LWD data. MWD tools provide direction and inclination data and enable the well to be steered to a desired subsurface location. LWD tools provide data on resistivity, density, and porosity of the rock, while a drilling mechanics sub collects data on pressure, temperature, 3-axis vibration, downhole torque, and downhole WOB. However, most MWD and LWD tools have a maximum temperature rating of 175°C, limiting drilling operations to this temperature threshold. Downhole tools must be innovated to be deployed in high-temperature domains for SHR projects to succeed. Section 5 provides a thorough analysis of state-of-the-art high-temperature downhole sensors and monitoring systems, assesses their TRL status, and provides innovative pathways to overcoming remaining technology gaps for SHR drilling.

3.3 Requirements for temperature management equipment

An SHR drilling project requires a robust temperature and pressure management system, along with a well control/integrity system that can manage hot fluids. The system must be designed to deliver a working fluid, typically water, to the bottom of the well at total depth (TD) to cool the drill string and downhole electronic components below the maximum temperature threshold of the tool or component with the lowest temperature specification. An alternative drilling fluid that could be used for SHR drilling is supercritical carbon dioxide (sCO_2) controlled with an MPD system that maintains liquid CO_2 in the drill pipe and gaseous CO_2 in the annulus. Other methods for managing the bottom hole temperature include insulated drill pipe, mud coolers, flow rates, and continuous circulation. Section 6 provides a thorough analysis of state-of-the-art well temperature management technologies, assesses their TRL status, and provides innovative pathways to overcoming remaining technology gaps for SHR drilling.

3.4 Requirements for casing, cement, and corrosion inhibition

While largely outside the scope of this study (see *Bridging the Gaps: Well Design and Construction* by Suryanarayana et al., 2024), casing and cement are critical components of an SHR well. The drilling engineer designing the casing and the cement program must consider several factors. First, the last casing string or last uncemented hole section needs to be large enough to accommodate a sufficient flow rate to deliver the right amount of heat/energy back to the surface. Casing string size has a significant impact on overall project economics.

Second, the drilling engineer must consider the material properties and the wall thickness of the casing so that even after the casing strength has been de-rated due to the elevated bottom hole temperature, it still maintains the mechanical properties required to deliver the heat back to the surface for the design life of the project.

The third key factor is corrosion inhibition. The casing needs to be made of a material that can withstand the temperature and the chemistry of the fluids over the lifespan of the well. If the well is an EGS-style well, the produced fluids are likely to be mildly corrosive and, therefore, the casing material needs to be able to handle those corrosive fluids. If the SHR design is a closed-loop system, the chemistry of the produced fluid is likely to be more benign and less prone to corroding the casing, so more standard materials could be used.

Lastly, the cement design is also critical to the long-term integrity of the well. The cement needs to have little to no shrinkage or expansion at the borehole temperature. Various non-Portland cement designs have been tested up to 350°C (Arbad et al., 2022) and, according to engineers from Halliburton (Interview, 2024), there are cement formulations that will be able to deliver a strong casing bond at even higher temperatures. All the literature supports a cement design that includes pumping cement back to the surface in all casing sizes to provide maximum support to the casing, minimize casing expansion, and protect the casing from the thermal expansion of fluids in the void spaces which can result in casing collapse. SHR cement will also need to be reverse circulated to ensure the low-temperature retarding chemicals do not see SHR temperatures.

Further research is also needed to address the potential of formation creep or expansion at SHR temperatures and pressures. If the formation (or some of the component minerals within it) behaves plastically at elevated temperature and pressure, the last casing string may not need to be cemented in place. The formation would expand, create a seal, and stabilize the casing in the hole. Cement and casing are discussed in detail in a separate report in this series: *Bridging the Gaps: Well Design and Construction* (Suryanarayana et al., 2024).

3.5 Requirements for topside equipment

Reaching SHR requires wells with very deep true vertical depths, which must be considered before other drilling factors such as rock hardness, high friction coefficients, and elevated temperatures. The rig must be sized to lower, pull, and potentially rotate the heaviest string going into the hole. The substructure and derrick must be strong enough to lower and pull the deep 9 5/8" (or equivalent) casing. For example, the weight of a 9 5/8", 58.4 lb/ft, P110 casing at 20,000 ft is over a million pounds. The rig derrick and top drive must turn the whole drill string in a high-friction environment and provide adequate torque at the bit to fail the rock efficiently. Developers will need a rig with some of the highest specifications available today (e.g., the Doyon Rig 26 in Alaska, which is drilling exceptionally long O&G wells on the North Slope). We estimate the number of rigs with these specifications to be less than 50 worldwide.

The control system and auto-driller (i.e., fully automated control system) are vital equipment for an SHR rig. These electronic components optimize the control of drilling parameters and improve precision and control. When drilling through extremely hard rocks, it is important to precisely control parameters on the drill bits. If a managed pressure drilling (MPD) system is deployed, then it should be integrated with the rig's control system (e.g., NOV's NOVOS™, Nabors, H&P, Precision and Patterson).

MPD systems are required to manage the pressures and temperatures at the surface and ensure safe operations for the rig personnel. An MPD system is required for CO_2 working fluid but may also be necessary in SHR with a water-based system, especially if there is a risk of the water existing in multiple phases in the borehole.

Drilling SHR wells also requires a fit-for-purpose drilling rig and topside equipment that can power and integrate all the considerations discussed in this section (ROP, high-temperature downhole tools, temperature management equipment, drill string, casing and cement). For example, an MMW rig must have sufficient capacity to withstand 900 tons of force for the weight rating of the rig, and a 5,300-horsepower drawworks to raise or lower the metal waveguide to depths >7 km. Rigs with these capabilities do exist today but are rare and difficult to source (Houde, Araque, et al., 2021).

4. Rock-destroying equipment: Technology frontier and gap analysis

Rock-destroying technologies must overcome three core challenges to drill to SHR:

1. Drill to supercritical conditions >374˚C,
2. Drill to >6 km through hard rock where most SHR regimes are found, and
3. Achieve rapid increases in ROP through hard rock, cutting back drilling time by >50 percent.

These challenges are inherently linked. To reach SHR, we must drill exceedingly deep wells into hard rock, which would incur prohibitively high costs with existing drilling technologies. Improving bit performance and maximizing bit longevity to reduce trip time are equally important for increasing ROP. In this section, we assess three categories of drilling techniques, assigning each a technology readiness level (TRL):

1. Conventional rotary drilling (PDC, roller cones, and hybrid PDC/Roller cone systems),
2. Hybrid conventional drilling (percussive, waterjet, and particle impact), and
3. Direct energy (plasma and millimeter-wave).

The majority of conventional and EGS geothermal projects are drilled with a conventional rotary drilling methods and some with percussive methods. Therefore, these mature drilling technologies are the most advanced technologies for reaching deeper, hotter regimes. Major advancements in ROP have been demonstrated in recent EGS-type projects in hard rock. Rotary methods, however, are originally designed to cut through soft lithologies and must continue to be adapted and improved for geothermal projects in hot, hard rock. Percussive, waterjet, and particle impact drilling are methods that specifically target the brittle state of basement lithologies and may lead to further leaps in drilling efficiency.

As well depths increase, both rotary and hybrid conventional drilling methods will increasingly face challenges from excessive string weight, high frictional resistance, and exceedingly long trip times, possibly negating advancements in ROP generation. The advantages of direct energy methods—namely minimal downhole equipment, few complications from high temperature and pressures, and less (or no) trip time—may ultimately provide a better pathway to SHR. Direct energy methods are highly novel, however, and may not be commercializable this decade.

4.1 Conventional rotary drilling

Conventional rotary drilling techniques are the most mature and accessible drilling methods today. Most of the equipment is readily available from vendors and drilling contractors. A major benefit of drilling with conventional drill bits is the use of standard bottom-hole assembly design, drill string design, and top-side rig equipment. Conventional rotary drilling techniques can be modified for SHR projects by optimizing the drill bit design and enhancing the downhole assembly with heat-resistant materials.

This section explores four sub-categories of rotary drilling innovation:

- Efficiency (the optimization of bit and cutter design for hard rock drilling, control of downhole drilling parameters and bit dysfunction mitigation to improve productive drilling time and reduce drilling costs),
- High temperatures (specialized drill bits for SHR temperatures),
- Directional drilling (methods and equipment for drilling deviated wells in SHR), and
- Performance in interbedded formations (bit designs and methods to overcome bit wear from heterogeneous formations that can be encountered in basement volcanic sequences).

4.1.1 ROP generation

Increasing efficiency with cutter shape and bit design

In traditional hydrocarbon drilling operations, fixed cutter drill bits with polycrystalline diamond compact (PDC) cutters are typically used for lithologies of soft-medium hardness, while roller cone bits are used for hard rock lithologies (Graham et al., 2017; Petty et al., 2020; Pink, Patterson, and Thoresen 2023; Self et al., 2021). Roller cones, or tricone bits (Figure 5), comprise three rotating cones with tungsten carbide inserts mounted on each cone. Applying weight-on-bit (WOB) causes the mounted inserts to impact and fracture the formation, which is removed by the continued rotation of the cones that clear away the crushed rock (Roberts et al., 2022).

While roller cones are typically used for conventional geothermal projects, the rotating components of these bits are prone to failure due to high frictional heating and high WOB and are limited by the temperature ratings of elastomer seals and bearing assemblies (approx. 130˚C) (Petty et al., 2020). PDC inserts on tricone bits have been used to improve bit life and ROP, but still proved less effective than fixed cutter bits (Self et al., 2021). Roller cone bits rated to 300˚C were used at IDDP, but even though the design proved robust and reliable, the ROPs were still only 2-10 m/hr—a consequence of the hard, volcanic formation.

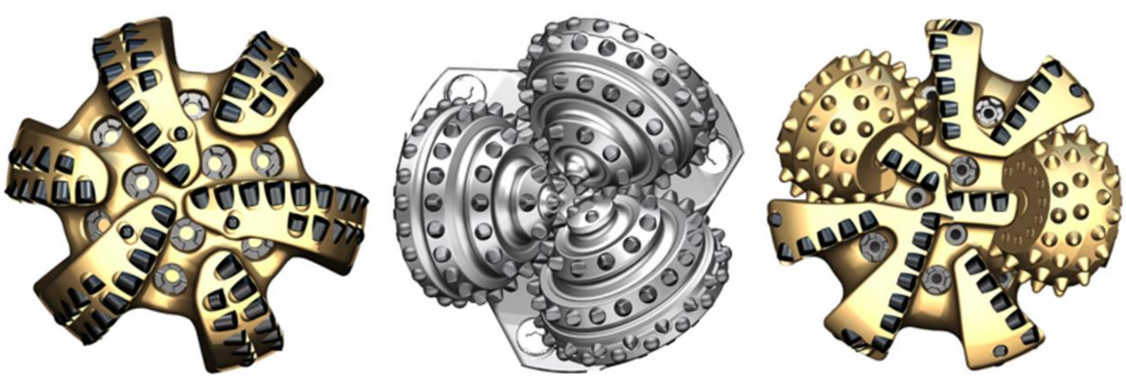

Figure 5 Polycrystalline Diamond, Roller Cone and Hybrid PDC + Roller Cone bits. From the Baker Hughes Vulcanix™ Geothermal bit line (Baker Hughes, 2024)

Fixed cutter bits have no moving parts and shear through rock formations. They are either driven from the surface by the rotation of the drill string, driven downhole with a mud motor, or a combination of both. Like roller cone bits, the cutters point-load the formation with applied WOB, crushing rock that is removed as the bit progresses downhole (Self et al., 2021). Fixed cutter bit performance has been significantly improved in recent decades by advancements in cutter grade and shape, with materials resistant to thermal abrasive wear enabling their use in hard rock formations, including those expected at deep geothermal sites. These bits have been further engineered to cope with supercritical geothermal settings, where elevated risks of thermal wear, mechanical damage, lateral vibration, and excessive torque are expected (Roberts et al., 2022). Finite element analysis, laboratory experiments, and in-field testing on axial impact and thermal wear have shown that V-shaped cutters outperform round cutters in ROP by 16-57 percent depending on rock type, and round cutters failed before the V-shaped cutters under thermal-abrasive and axial stresses (Rahmani et al., 2021).

An example of high-temperature, abrasion-resistant drill bits for geothermal drilling is the Vulcanix™ line by Baker Hughes. The Vulcanix™ Tricone bit (Figure 5) features a patented all-metal sealing and bearing system, with a stabilizing bit configuration rated to 260˚C. The tricone bit has been used in a series of wells in Turkey, some reaching up to 300˚C, with a record performance of 3,680 m in 36 days. These wells are not SHR, not exceedingly deep, and were drilled through quartz-schist type lithologies; therefore, performance may differ in other hard rock formations. Baker Hughes' Vulcanix™ PDC bit was deployed at Utah FORGE, achieving a maximum ROP of 43 m/hr and an average ROP of 23 m/hr, drilling 34 percent longer runs than planned. Their bit is equipped with ShockWave™ shaped cutters that enhance durability and improve bit longevity and Prism™ shaped cutters that apply a point load to absorb load and mitigate breakage under high WOB. The FORGE tests demonstrated high ROP in hard rock, but the temperatures were <250˚C. Therefore, further design and testing for SHR conditions are required. Lastly, the Vulcanix Kymera™ hybrid PDC and roller cone bit was used to drill through high-temperature (<230˚C), hard, volcanic formations in Japan. Two wells were drilled (up to 50˚ inclination) in just 32 percent and 43 percent of the planned drilling time due to increased ROP performance. This bit should be deployed to hotter and deeper wells for further performance testing.

NOV tested its novel PDC-cutter shape and bit at the Tauhara Geothermal Field in New Zealand. The bit was specifically designed to withstand thermal and abrasive wear and front-face thermal overloading, using cutters enhanced with stronger/denser diamond bonds, tougher carbide substrates, and high-pressure platforms (Roberts et al., 2022). In-field performance of this bit (referred to as the "Steam-Trooper,") was tested against traditional PDC bits, tricone bits, and hybrid bit designs. It demonstrated a 16 m/hr ROP and superior bit longevity, completing an interval of 650 m. The bit showed minimal wear after this run, so it was redeployed and completed another 1,625 m run (1,027-1,541 m longer than the tricone bits and 773 m longer than hybrid bits). However, these runs were achieved in sedimentary layers. The bit experienced highly erratic torque when it encountered the hard-rock rhyolite formation (Roberts et al., 2022). While this bit has demonstrated impressive longevity, it may require further innovation and testing for SHR and hard rock conditions.

The optimization of shape cutter and bit design for hard rock drilling is well documented and well tested. However, the designs have not yet been run in SHR conditions. Further bit and cutter engineering may be needed to cope with the plastic behaviour of rock at the brittle-ductile transition.

Pathways for further research and experimentation to overcome this uncertainty include:

- Finite element analysis of cutter and bit performance at super-critical depths and temperatures (e.g., Rahmani et al., 2021; Rasyid et al., 2021),
- Laboratory experiments in brittle-ductile conditions (e.g., Rahmani et al., 2021; Rasyid et al., 2021; Roberts et al., 2022), and
- Field experiments in brittle-ductile conditions with state-of-the-art robust drill bits, such as the Steam-Trooper or Vulcanix™ Kymera.

Increasing efficiency with bit dysfunction mitigation

Standard drilling optimization methods improve ROP and bit life using techniques such as real-time surface MSE surveillance, testing bit/BHA design, drill bit forensics, and parameter mapping (Sugiura, 2021). At Utah FORGE, mitigation against drilling dysfunctions, such as stick-slip and bit balling, was achieved by improving monitoring systems and topside communications. It is well-documented that specialized training of drilling personnel on the physics and signatures of dysfunctions significantly improves ROP and can result in up to 30 percent reduction in total drilling time. Managers at Utah FORGE consider the two-day training facilitated by Utah FORGE to be one of the key factors in the ROP improvements achieved at their wells. This training ensures that all drilling personnel are uniformly informed of the causes and signatures of bit dysfunction and equips them with the diagnostic skills needed to overcome these performance failures (Dupriest and Noynaert, 2022).

The balance of WOB and MSE management must be tailored to the specific context of the drilling project. In other words, the strategy used to optimize these parameters at one site may not work at another. Other factors that may impact efficiency and dysfunction management include operator fatigue, miscommunication, and varying experience levels. These factors can lead to human error that may impact drilling performance. Further experiments with automated or AI-assisted drilling systems with high TRL values could lead to improvements in ROP. For example, the REVit® ZT system from Nabors was successfully implemented at Utah FORGE to mitigate stick-slip dysfunction (Figure 6). Similar software tools exist from multiple vendors, and all improve the performance of the drilling system and reduce vibration.

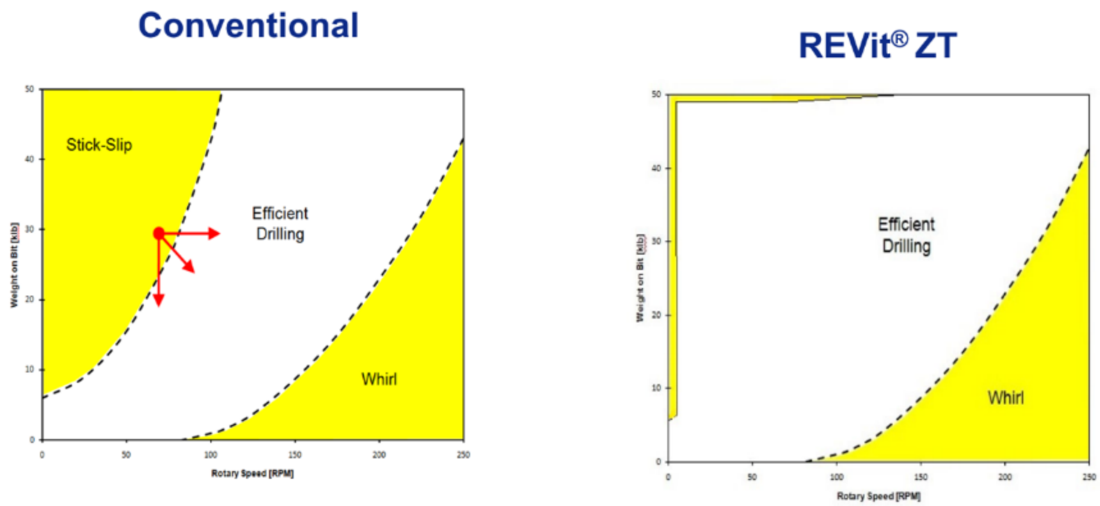

Figure 6 WOB and RPM regimes conditions for stick-slip dysfunction for conventional versus REVit®ZT drilling methods. (Nabors, 2023)

Automated systems could include Corva's AI-based ROP optimizer for predictive drilling, in combination with Nabors' SmartSuite. The SmartROS® Rig predictive drilling system has been shown to increase ROP by 61 percent for neighbouring wells and is deployable on any rig. The SmartNAV™ automated directional drilling guidance is designed to improve wellbore placement accuracy, has shown significant reductions in drilling time by 25 percent in comparative case studies, and is compatible with steerable or rotary steerable operations. The SmartDRILL™ automated drilling system reduces vibrations and shock of downhill tools (reducing unplanned trips) and the SmartSLIDE™ directional steering control system optimizes cycle time.

To further improve WOB and MSE management, automated or assisted drilling rigs should be deployed at ongoing geothermal sites, such as Utah FORGE, or future EGS experimental sites such as Newberry in Oregon and Chevron's project in California, both of which were awarded funding through the Department of Energy's EGS Pilot Demonstrations program in 2024. The MSE management and ROP of automated or assisted drilling rigs could be directly compared to fully manual drilling rigs. Comparing MSE management and ROP between automated systems and traditional manual drilling rigs will provide valuable insights into the potential benefits and areas for improvement. This research will not only advance our technical knowledge but also guide future investments and innovations in geothermal energy extraction.

4.1.2 High temperatures

For deep geothermal drilling, conventional drill bits must be adapted to cope with exceedingly high temperatures (>300˚C). Thermal damage is typically exhibited at the cutter shoulders, where cutter shear length and sliding distance are highest. Various round and V-shaped cutters have been engineered by NOV with denser diamond grades that are resistant to abrasive wear. These cutters also achieve greater durability against thermal wear by removing cobalt catalysts within the diamond at the cutting edges, increasing the diamond temperature rating from 700˚C to 1200˚C (Roberts et al., 2021; Self et al., 2021).

The dynamics of the fluid channeled through the top of the bit also play a critical role in regulating bit temperature, minimizing thermal abrasion, and cleaning the cutters. The main parameters affecting hydraulics include cooling fluid flow rate, nozzle configuration (Figure 7), mud weight, total flow area, and mud type. These parameters can be optimized to distribute the correct amount of cooling to the most vulnerable cutters (Roberts et al., 2021).

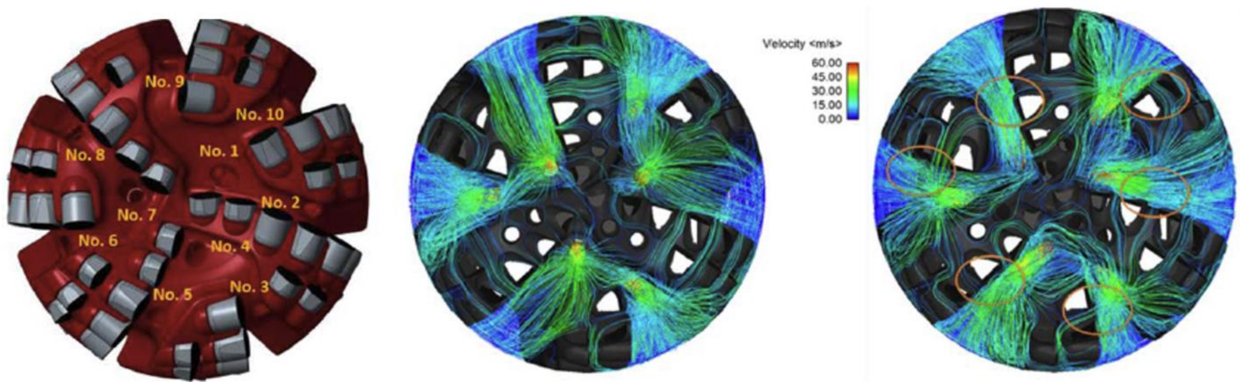

Figure 7 Nozzle configuration to optimize drill bit cooling with fluid flow
Left shows the placement of 10 nozzles on an optimized bit, center/right shows the flow distribution and velocities from six nozzles on two bits (Roberts et al., 2021).

As discussed above, the Baker Hughes Vulcanix™ tricone and hybrid bits are rated to 177˚C, 288˚C, and 300˚C using all-metal cone seals, high-temperature rated lubricants, and upgraded bit metallurgy. These bits underwent laboratory experiments with 300˚C water-based drilling mud, 10,000-30,000 lbs (4,500-13,600 kg) WOB, 90-180 RPM, and 6000 psi into Sierra White granite. There was no loss of grease, and seals/bearings retained their diaphragm depth, indicating no loss of lubricants that would lead to frictional wear. Drilling engineers have also observed that carbide outer compacts in the bits had minimal wear (Petty et al., 2020; Stefánsson et al., 2018).

These bits were later tested at the Iceland Deep Drilling Project (Section 2.2) and demonstrated an average ROP of 4.2m/hr and 3.4 m/hr for the 300˚C and 288˚C bits respectively. Hybrid and conventional bits were also used to deepen the vertical section of the well. Meanwhile, coring bits, along with rotary, motor-driven and metal-to-metal (M2M) BHA, were used at various stages. The highest ROP achieved was 10.3 m in run five by a 300˚C roller cone under 121˚C conditions, but this was only sustained for 69 m due to circulation losses and the deployment of a coring program that was unsuccessful (see Stefánsson et al., 2018 for a full review of bit performance per run).

Several drill bit technologies can withstand 300˚C; however, the remaining 75-100˚C expected at supercritical temperatures must still be “unlocked.” It should be noted that drilling through 400˚C rock does not mean that the bits will encounter 400˚C due to significant cooling from the drilling fluid. The PDC cutters may encounter 400˚C but are rated 800˚C. Access to these extreme temperature conditions remains a major challenge for experimentation. Some potential solutions include:

- A global consortium of HTHP labs to conduct necessary R&D experimentation and coordination between industry partners with innovative technologies to co-develop the drill bit technologies with supercritical temperature capacities;
- On-site experimentation at high-temperature locations, specifically involving sites studied at the Japan Supercritical Project, Newberry Volcano, and the Iceland Deep Drilling Project; and
- Thermal analysis for bit design with software such as ReedHycalog up to 450˚C (as their highest temperature tests are only up to 250˚C).

4.1.3 Directional drilling

Precise directional drilling tools are required to deploy the lateral well sections that can operate in >375˚C and at great depths. The borehole must be placed in a precise location to either enable a well-to-well intersection or to optimize lateral borehole separation for reservoir creation and stimulation. Both cases require deviations from a sub-vertical well. Therefore, directional drilling technologies must also reach SHR capacity.

Directional drilling requires a drive system that can be steered in three dimensions. Using traditional technology, three-directional steering is performed with a mud motor and/or a rotary steerable tool. Both these drive systems have temperature limitations of between 175˚C and 200˚C, thus the drilling system will need to be cooled below these temperatures. Companies like Hephae are pushing the temperature limitations of both rotary steering systems (RSS) and MWD to above 200˚C (Section 5). The improved efficiencies from an RSS system were observed at the Utah FORGE's production well 16B (78)-32, that was inclined at 65° parallel to the injection well (16A (78)-32). The production well achieved a much higher ROP due to increased bit aggressiveness and the implementation of a rotary steering system (RSS) in the inclined sections of the well. The primary improvement from the RSS was the hole smoothness (Figure 8), which drastically reduced frictional drag on the drill string and the integrity of other down-hole components such as packers (Noynaert, GRC 2023).

Other important considerations for directional drilling emerge from the nature of the rock itself. To access SHR, wells must be steered through hard basement formations that have high friction coefficients. Taking the rock type into consideration, the assembly must be designed to minimize vibration. Tools like roller reamers must be run in the BHA, and the drill string must be as stiff as possible to minimize torsional vibration and maximize weight transfer. To reach the vertical depths needed for SHR (5-10 km), it is essential that drilling is executed with the lowest number of doglegs and the lowest tortuosity possible (otherwise the rig may run out of available surface torque), which may require more investment in RSS tools to maintain verticality.

In the last hole sections of SHR wells, lubrication will become an important part of directional drilling. The ability to steer the wellbore and minimize vibration may require the addition of lubricants to the drilling fluid. Research into higher temperature variants of these lubricants is needed. Graphite can be used, but it is expensive and can reduce reservoir permeability (so it should not be used in the final hole section of an EGS well).

Directional drilling an SHR well above 374˚C is possible today but, depending on the efficiency of the temperature management system, it may be necessary to complete all the directional work with electronic tools before the highest temperatures are encountered. The modelling work done on insulated drill pipe suggests that directional work can be done at depths of 8,000 m and with formation temperatures >374˚C, but a set of full-scale test joints needs to be produced and tested, followed by the development of a complete string to validate that the bottom hole circulating temperature can be maintained below the operating temperature maximum of the tools.

Deep SHR wells must also consider the surveying program. To be able to accurately hit a small target or maintain exact proximity to another well, the survey program may require running gyro tools at the end of each section and advanced survey techniques while drilling. In SHR CLG wells, magnetic ranging tools will (discussed in Section 5.1) be required to make a well-on-well intersection; these tools are currently being tested in Geretsried, Germany by Eavor (but not under SHR conditions).

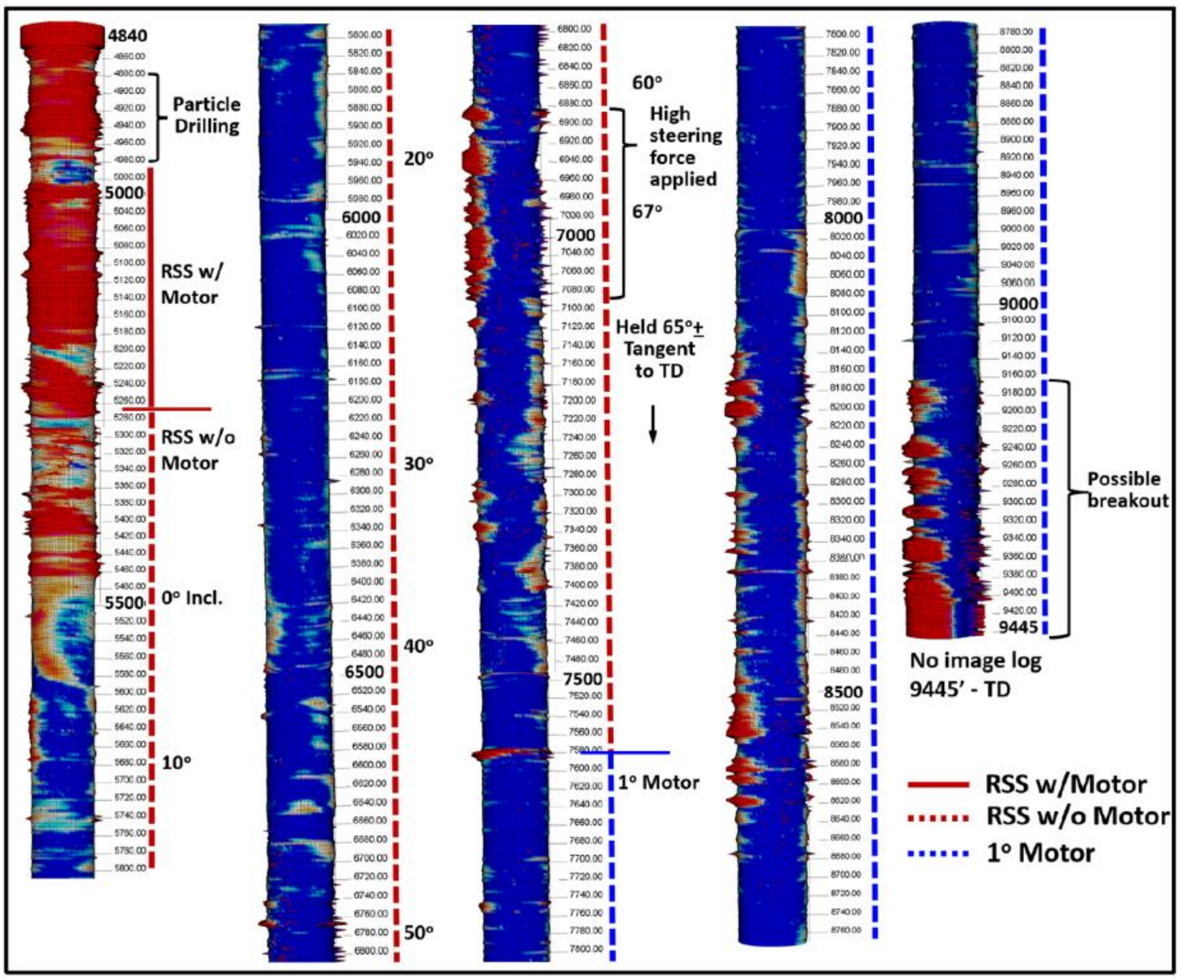

Figure 8 Profile of curved section of well 16B, showing correlations of hole smoothness and rotary-motor systems used (Noynaert, GRC 2023)

4.1.4 Performance in interbedded formations

SHR conditions are generally found in basement rock at depths >5 km. Engineers at Fervo Energy have stated that lithological hardness becomes more uniform with increasing depth, and current drill bit technology will not be at risk of premature bit-wear from drilling through heterogeneous formations, such as sediments, interbedded tufts, calcites, and granite. In heterogeneous media, one ReedHycalog bit managed to drill through sediment, interbedded tuffs, calcites, and granite, demonstrating that conventional bits are sufficient in interbedded domains. Conversely, experts at Utah FORGE consider interbedded formations to be a first-order innovation gap for hard rock drilling, and the Stn-1 project in Finland encountered complex geology in the Fenno-Scandinavian shield, a geological regime with presumably uniform rock hardness.

When PDC cutters transition from soft to hard formations in heterogenous domains, the drill string rotation is slowed, yet the force on the bit remains the same (Graham et al., 2017). The excess force dissipates through the cutters, causing breakage or chipping if the force exceeds their fracture strength. Tricone bits may be better suited for these conditions, as they penetrate the rock with the weight of the drill string rather than the rotational force applied by fixed cutters (Graham et al., 2017; Rahmani et al., 2021).

Alternatively, Schlumberger has innovated a conical diamond element (CDE), fixed with PDC cutter teeth (Figure 9) that improve the implementation of fixed cutter bits in hard, interbedded rock. CDE teeth are 25 percent more resistant to wear, reduce vibrational founder on the bit, and have 50 percent more impact strength and 50 percent more diamond thickness than PDC teeth. Where PDC cutters shear through rock, CDE cutters “plow” through the formation, and their position behind the point of maximum tangential velocity experienced by the PDC cutters protects them from impact damage (Graham et al., 2017). They also use 26 percent less torque than PDC bits, improving directional capability due to the reduction of torque fluctuations at the tool-face (Rasyid et al. 2021).

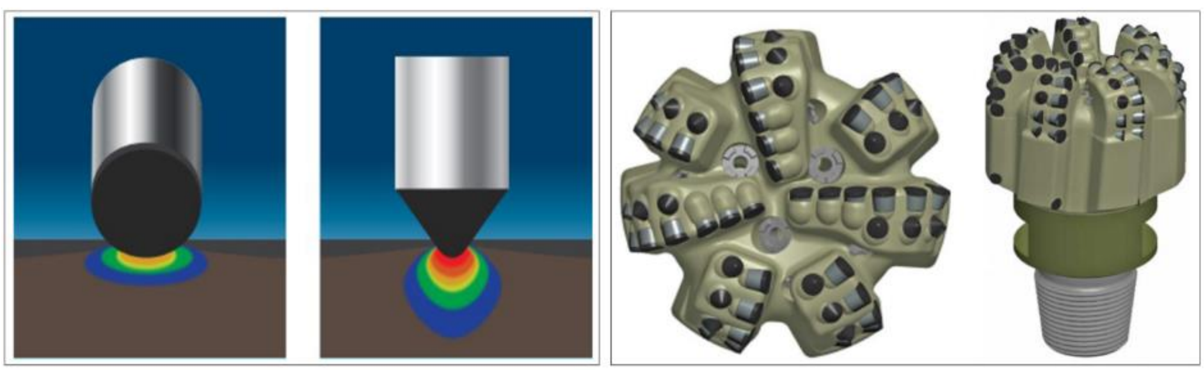

Figure 9 Carbon Diamond Element Drill Bits

(Left) Finite element analysis of point load stresses on the formation from PDC and CDE cutters, (right) the mounting of PDC and CDE on the fixed cutter drill bit (Roberts et al. 2022).

Rasyid et al. (2021) performed finite-element analysis of CDE bits of varying sizes before Schlumberger drilled a test well at the Blawan Ijen geothermal field in Indonesia. Their simulations tested drilling andesite, tuff, and brecciated volcanic formations (with 6, 7, and 8-bladed CDE bits in comparison with tricone bits) for 17 ½”, 12 ¼”, and 9 ¾” well sections. The CDE bit consistently improved stability (less vibrational founder) and ROP compared to tricone bits. In-field drilling in similar rock types and well pressure conditions for the Blawan Ijen test wells resulted in an ROP range of 5-30 m/hr, saving 6-9 days of drilling compared to a tricone bit (Rasyid et al., 2021). Furthermore, the CDE bit was tested in heterogeneous lithologies at The Geysers and achieved 4-8 m/hr ROP—a

45 percent increase from the PDC bit, with the potential to be further improved (Graham et al., 2017; Song et al., 2023).

The TRL of fixed cutter drill bits equipped to excavate interbedded formations is 9, as demonstrated by the ROP tests at the Blawan Ijen geothermal field. However, these bits have not yet been tested under supercritical conditions, and are not yet rated for 400˚C. Recommendations for further experimentation and testing include:

- Continue to use Utah FORGE as a site for research on overcoming interfacial severity (specific methods include adaptive drilling methodologies that can detect fractured lithology before intersection, potentially through acoustic and sonic techniques that can be incorporated into automated drilling methods),
- Deploy CDE bits in deep, cold, heterogenous geologies (e.g., Stn-1) to compare performance to conventional rotary bits,
- Conduct in-field tests or experimental bench tests in a laboratory with SHR capacity, and
- Create the equivalent of Utah FORGE in a volcanic geological environment featuring igneous rock with a high variability of hardness.

4.1.5 Gaps and challenges for SHR

Conventional drilling is the primary method for accessing geothermal resources in hard crystalline formations, with some cases in supercritical temperatures. Individual bits can be specialized for extreme temperatures, interbedded formations, or extended bit life; however, no single bit features all these specifications. Combining these features may be the most efficient way to accelerate conventional drilling for SHR applications. However, this innovation requires coordination between major drilling firms.

The main obstacles to coordinating efforts between major drilling firms are the reluctance to share trade secrets and intellectual property. However, there are ways around this. For example, NOV and Schlumberger have demonstrated the ability to collaborate through licensing agreements. To propel this technological frontier forward, we need to develop creative approaches for incentivizing collaboration while also protecting intellectual property and ensuring the profitability of firms.

The other major gap for drilling into SHR with these state-of-the-art technologies is the lack of accessibility to supercritical conditions. There are no known laboratories capable of testing these drilling technologies at >374°C and testing in-field with these conditions is expensive and high-risk. Following extensive experimentation in a controlled laboratory setting, high-temperature, SHR-rated drill bits and BHA should be deployed in active SHR or EGS projects for further optimization of deep, hot rock drilling. The Stn-1 wells in Espoo, Finland, which have ceased commercial production of direct heat, may offer a unique location to verify ROP performance at extreme (>6.3 km) depths in hard rock.

The Newberry Volcano or IDDP project can offer access to extreme downhole temperatures and are ideal locations for experimenting with high-temperature bits and tools, insulation technologies, and alternative drilling fluids such as sCO_2 (see Section 6.2). The Japan Beyond-Brittle Project also strives for supercritical depths and temperatures and may offer the chance to experiment with these various drilling technologies.

Further experimentation on drilling into supercritical conditions could be facilitated by the Utah FORGE demonstration site (with consent from the DOE), and by recipient projects of the recently announced DOE Geothermal Earthshot funding (Mazama Energy at Newberry Volcano, Chevron in Sonoma County, and Fervo Energy in Milford, Utah). For drill bit design, modelling, and rig servicing products, NOV, Nabors, and Schlumberger have facilities and a breadth of expertise to engineer tools to overcome specific technology gaps, in partnership with specialized research entities and universities.

4.2 Hybrid conventional drilling methods

While generally not as mature as conventional rotary drilling methods, hybrid conventional methods may ultimately provide the optimal pathway to accessing SHR. Percussive and waterjet drilling were initially designed for unique applications in hydrocarbon exploration and have been adapted for deep, hard rock drilling. Meanwhile, particle impact drilling was developed specifically for hard rock drilling. Most hybrid conventional BHA's are combined with rotary drill bits, with the percussive/waterjet/particle impact modifications designed to target the brittle state of hard rock formations to improve drilling performance and increase ROP. For example, waterjet methods alter the stress state at the bottom of the hole to improve its failure, and percussive and particle-impact fracture the brittle hard rock.

The same core challenges facing conventional drilling apply to hybrid conventional drilling methods, namely: efficient drilling through deep, hard rock formations under exceedingly high temperatures and pressures. The TRL status of percussive drilling is 7, while waterjet drilling and particle drilling are at a TRL status of 4-5 for superhot hard rock applications that may be advanced with further in-field testing. The advantages of hybrid conventional drilling may prove superior to purely rotary techniques in the pursuit of SHR, although further experimentation in SHR conditions is required for all methods.

4.2.1 Percussive drilling

Percussive (i.e., hammer) drilling is equal in maturity to rotary drilling methods and has demonstrated promising performance in hot, hard rock drilling for SHR. A typical percussive BHA consists of a drill bit, a piston, and hammer casing. The piston pneumatically impacts the bit repeatedly into the rock, with the casing connecting the hammer to the drill string (Depouhon et al., 2015; Song et al., 2022). Percussion drilling has produced improved hole geometry, reduced stress on the drill string, improved bit longevity due to reduced contact time with the rock, and produced better cutting shape and size for transport. Percussive drilling can, however, lead to wellbore instability due to excess energy transfer in soft formations, poor performance in soft rocks, and vibrational dysfunction, and can have uncertain optimal hammer frequencies (Bruno, 2005).

Percussive drilling is commonly used for hydrocarbon exploration and has demonstrated significant ROP: >24 m/hr in soft rock formations, and up to 20 m/hr in hard rock formations at 6,000 m depths. Fervo has demonstrated that percussive drilling methods can maintain a straighter well path relative to PDC bits (because of the lower WOB). Several firms are currently adapting percussive drilling methods to reach supercritical temperatures. UK-based Strada Global and HydroVolve systems both combine rotary and percussive methods, and the EU Horizon 2020-funded Orchyd project combines Drillstar Industries' MUDHammer with a waterjet system.

Alternative pneumatic systems for percussive BHA have been investigated by Lehmann and Reich (2015) to optimize very deep, hard rock drilling. These systems include mechanical, thermo-mechanical, hydraulic, and electromagnetic drives. Numerical experiments on percussive drilling up to 300˚C have shown that the tensile strength of rock decreases with high temperatures (Song et al., 2022). Therefore, SHR may actually enhance ROP for percussive drilling.

Strada Global

Strada has a fluid hammer operating system that combines rotary and percussive drilling designs. It applies a dual-fluid system, using fresh or saline water to drive the hammer, which reduces corrosive wear on the bit. In Australia, Strada's fluid hammer was used to reach depths of over 6,000 m, achieve 20 m/hr ROP in 200 MPa hard rock including granite and basalt, reduce drilling costs by 70 percent, improve bit longevity, and drill in underbalanced and overbalanced conditions (Olijnyk, 2024).

HydroVolve

HydroVolve's GeoVolve HYPERDRIVE system (Figure 10) is a hybrid rotary and percussive drilling method, designed specifically to drill deep, hot, hard rock wells for geothermal projects. A rotating PDC bit drills with the same mechanics as a conventional drill system, but the BHA is augmented to deliver a cyclic axial impulse that pre-fractures the rock, reducing its compressive strength and decreasing the rotary shear required to clear the rock. This system is purely mechanical; therefore, it is not prone to electronic failures due to high temperatures. Specific capabilities of the HYPERDRIVE system include the ability to: (1) operate up to 300˚C; (2) be powered by the pressurized flow of any drilling fluid, from freshwater to high-density drilling mud; (3) maintain typical hydraulic systems; (4) maintain circulation density and sufficient wellbore pressure; and (5) protect the BHA from impact force damage.

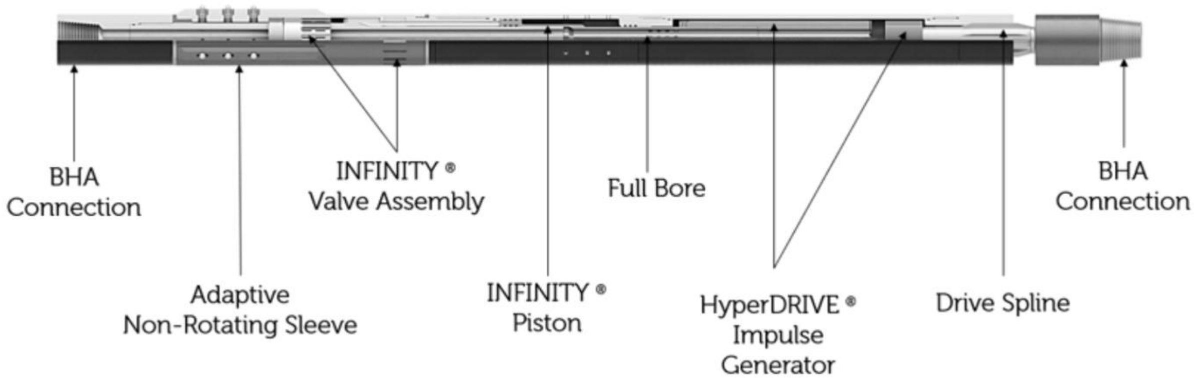

Figure 10 Schematic of the HydroVolve GeoVolve HYPERDRIVE system (Moyes et al., 2023)

The system is compatible with a conventional rotary BHA. The drilling mud hydraulically drives a high-frequency, percussive axial impulse system transmitted through the bit, fracturing the rock cleared by the rotary drilling mechanism. Designed in partnership with ZerdaLab, the bit is optimized to cope with axial impulse load, using a large shoulder radius and CDE-type cutter configuration to maintain lateral stability. It has no elastomeric seals and is thus ideal for SHR conditions.

Full in-field and laboratory testing has been conducted using the HydroVolve assembly at their onshore Drilling Test Facility, using a rig with downhole monitoring of WOB, axial impulse load, pressure, ROP, RPM, and torque, with data transmitted at 10,000 Hz. This initial testing was followed by a series of trials in Hungary achieving an ROP of 2 m/hr for a total depth of 229 m, sustaining downhole temperatures of 220˚C in interbedded sedimentary formations. This equipment was also used to drill 5,800 m through interbedded sediments in Ukraine sustaining 2 m/hr (HydroVolve Case Study Documentation, 2023). Further testing in hard, SHR conditions is required and ROPs of greater than 2 m/hr will need to be demonstrated to be competitive with other technologies. Field trials in New Zealand are scheduled to take place in 2024.

Orchyd Project

The EU Horizon 2020-funded Orchyd Project, in collaboration with Drillstar Industries, developed a hybrid high-pressure waterjet and mud hammer. This hydro-mechanical drilling system operates to reduce the confining stresses of the rock at the drilling front, improving drilling efficiency and reducing the impact of hard, abrasive formations on bit-life. The release of stress is achieved by grooving the rock at the drilling front with the high-pressure water jets, causing the unloading of compressive stresses and promoting fracture propagation to reduce rock strength (Wang et al., 2021). The Drillstar MUDHammer, equipped with a diamond-insert reinforced kerf-shaped drill bit (Figure 11), then impacts the weakened rock at high frequencies, generating cuttings that are cleared away with a circulating drilling fluid. The axial vibrations of the drill string also pressurize the water, reducing vibrational dysfunction and conserving energy.

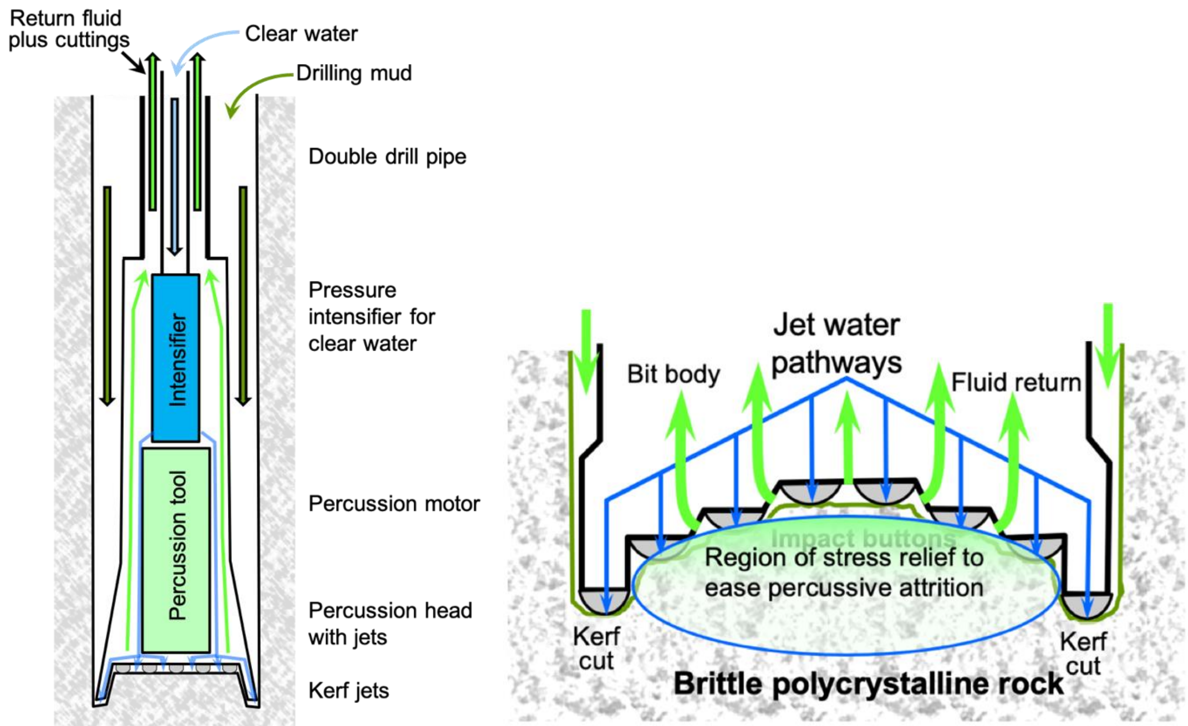

Figure 11 Orchyd and Drillstar hydro-mechanical drill system, and the bit-jet-rock interaction at the drilling interface. (Orchyd, 2023)

With these designs, current system testing at the ARMINES laboratory facility in Pau, France demonstrated an 80 percent increase in ROP with the combined system, a rate of 4-10 m/hr (Jahangir et al., 2022). With more planned updates on the way for design and validation, there is potential for this number to increase. The target of the fully completed system would be an ROP of roughly 20-25 m/h in hard rock. This drilling approach, however, has not been extensively tested in ultra-high temperature and pressure conditions.

Gaps and challenges for SHR

Percussive drilling, both with air and mud hammers, is at a TRL status of 7 for deep drilling into hard SHR. Several established firms are developing specialized BHA for deep geothermal drilling, and several frontier geothermal projects have invoked percussive drilling systems into their drilling program, notably Stn-1, Fervo, and IDDP-2. Drilling into SHR is within reach. The main challenge is access to locations or facilities with HTHP conditions.

Percussive drilling methods are likely to encounter challenges in SHR conditions. Air hammer drilling will not perform efficiently at great depths due to well instability and loss of force to the drill bit, and mud hammer drilling may incur substantial water loss if operating in porous or fractured media. A collaborative research project between Mines ParisTech and Drillstar Industries has identified four focus areas for how to adapt percussive drilling for deep geothermal projects (Gerbaud et al., 2022):

- Theoretical development, computational analysis, and experimentation on the stress regime at the drilling front in a deep borehole for optimizing cutting elements and bit configuration,
- Cutting element optimization at the rock-bit interface under specific drilling conditions,
- Design of a hydraulic hammer for 8 ½” boreholes, and
- In-field testing.

The MINES Paris Tech and Drillstar Industries study successfully designed an 8 ½” drill bit with a 300 percent ROP increase relative to conventional percussive systems in a hard rock bench test, demonstrating significant improvements in vibrational dysfunction. They have not, however, experimented in SHR conditions nor conducted substantial in-field testing. One approach to advancing their technology is to partner with research groups with the capacity to test at supercritical conditions, or field sites with extreme HTHP in-situ conditions, such as IDDP (like Strada Global’s drilling program at the Stn-1 Deep Heat project). The Department of CNPC Engineering Technology in Beijing has also conducted extensive modelling and laboratory experiments on stress wave propagation mechanisms and rock fragmentation up to 300˚C (Song et al., 2022). Collaborations between these groups could advance the modelling of HTHP conditions.

Percussive systems have achieved 25 m/hr ROP and reached supercritical pressures and temperatures. While rotary drilling systems have demonstrated superior ROP performance, percussive methods may achieve similar or better rates with further optimization for SHR and deployment in field settings. Suggested next steps include international collaboration to deploy SHR-rated percussive systems at in-field demonstration projects to further optimize this technology.

4.2.2 Waterjet drilling

Waterjet drilling uses high-pressure water to remove rock formations to create a borehole. This method weakens the formation within and surrounding the borehole, reducing the strain on the drill bit. There are two applications for waterjet-based drilling: (1) drilling lateral passages and (2) vertical drilling. Lateral passage creation (e.g., radial jet drilling) has only been used in soft lithologies for stimulating hydrocarbon reserves or conventional geothermal systems to increase their output. Vertical wells are drilled with either continuous high-pressure streams, pulsed streams, or through a combined system utilizing a conventional bit with jetting attachments.

Current system-level performance testing completed by the Orchyd and ThermoDrill projects shows a >30 percent reduction in stress within the rock formation at a rate of 4-10 m/hr ROP at 65 percent reduced overall cost (Orchyd, 2022) and a ROP increase of 50 percent at 30 percent of the cost (Stoxreiter et al., 2018) relative to conventional drilling methods. While these systems and designs have demonstrated significant performance increases, the full-scale technology requires further testing. Top-side equipment must be designed to support the extreme volumes of fluid delivered down hole (600 L/m in the case of the Orchyd Project), especially at extreme depths. Maintaining that pressure to depths of up to 10 km will be critical for the success of waterjet designs.

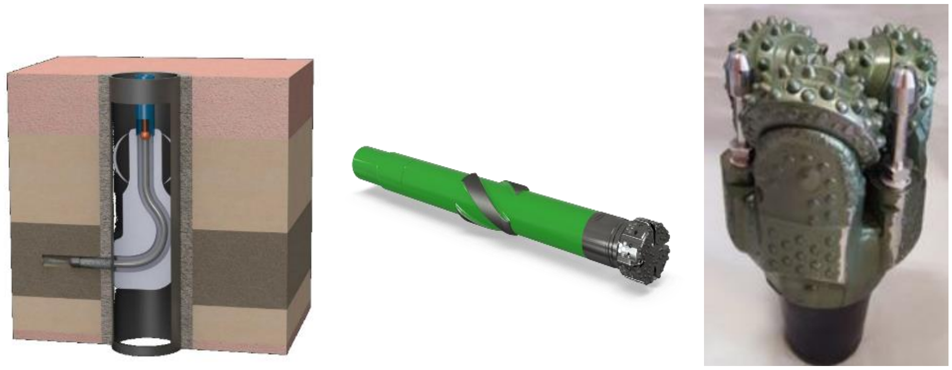

Figure 12 Breakdown image of a radial jet drilling system within a borehole.
(Left) (Kaldal et al., 2019), Drillstar's MUDHammer piston-based pulsed water drilling head (Center) ("Drillstar - MUDHammer," n.d.), and conventional drill bit with the addition of two high-pressure waterjet heads (Right) (Stoxreiter et al., 2019)

Gaps and challenges for SHR

While these developments have been tested in a conventional geothermal setting, further validation and development is required for SHR drilling. In the case of radial jet drilling, some key areas of design improvement were identified by Ahmed and Teodoriu (2023) at the Stanford Geothermal Workshop in 2023:

- Application in high compressive strength formations,
- Lack of and developmental need for directional control systems within the jetting system,
- Need for performance modelling in hard rock formations, and
- Flexibility and strength targets and designs for the required tubing within the systems.

Overall, waterjet drilling is most effective when combined with another drilling system. It increases overall ROP and enables a lower frequency of tripping to surface. The reduction of downhole stresses is one of waterjet drilling's biggest advantages. However, the technology requires more validation based on the standoff distance to the rock surface to maximize stress reduction. Surface systems need to be evaluated to ensure consistency with significantly increased flowrates at long distances through the drill string.

4.2.3 Particle drilling

Particle drilling involves the injection of steel shots of various sizes into the drilling fluid through the drill bit. The impact of accelerated drilling fluid bearing the steel shots weakens the formation to improve efficiency of the PDC drill bit. Increasing the run length per bit will improve the economics of SHR drilling by improving bit longevity and reducing trip time.

Particle drilling is a process whereby steel shots are injected at pressure into the main flowline that runs from a rig's pumps to the drill string. The steel particles then flow down the drill pipe into the drill bit and accelerate to 500 ft/sec. The drill bit rotates at roughly 60-80 RPM, and the particles cut a bottom-hole pattern in the rock (Pink et al., 2022). The remaining half inch of de-stressed rock is then removed by the PDC cutters in the reaming section of the bit (Figure 13).

In January 2021, the company Particle Drilling (PD) and NOV partnered to design a hybrid particle impact and PDC bit and conduct lab and field testing in hard igneous rock in central Texas. This trial demonstrated significant longevity improvements relative to traditional PDC bits, drilling 990 ft in extremely hard (45,000 to 50,000 psi) pink granite at 45 ft/hr for 990 ft (whereas a single PDC bit was worn after 122 ft). The PD/NOV bit was tested at Utah FORGE in 2023, with the aim to drill a 9 ½” hole section 500-600 ft in one run at 75 ft/hr, and capture and recycle all the shots. The two drilling runs were unsuccessful, with penetration depths of less than 70 ft, a result of the nozzle configuration on the hybrid drill bit. Based on the post-run analysis, the PD/NOV team developed a new hybrid bit, specifically designed for Utah FORGE’s granite. This technology has potential for generating high ROPs and completing long bit runs as the steel shots can be continuously replaced at the surface. With further runs and iterative design improvements, this may result in less trips and reduced costs.

Figure 13 Latest deign of 8 ½" particle impact/PDC hybrid bit. (Pink et al., 2023)

A significant technology gap is compatibility with MWD. To drill directional wells efficiently, particle drilling requires an MWD telemetry system that can send signals uphole without a pulser or modulator. Currently, when putting a conventional MWD tool in the BHA, the steel shot will damage the modulator or pulser. Conversations with Halliburton suggest that there is potential for the Halliburton negative pulse tool to be modified to handle steel shots. Wired pipe could also be used as a telemetry method if the circulating fluid temperature is kept below 150°C.

Canopus Drilling Solutions (CDS) in the Netherlands is also developing a hybrid particle impact and PDC system (Interview with Jan Jette Blangé, Feb. 2024). Additionally, they are designing and testing a complete MWD package and steering unit; the complete system is called Directional Steel Shot Drilling (DSSD). The Canopus system’s basic principles are the same as PD: it uses high-velocity steel shot on the hard brittle formation. The technologies differ in that Canopus uses the shots to steer the well and uses a PDC bit to remove the weakened rock, whereas PD solely reams a small section of destressed rock on the outside of the hole.

The Canopus system underwent significant testing and validation between November 2022 and June 2023 at the Rijswijk Centre for Sustainable Geo-Energy (RCSG) of TNO in the Netherlands (Knebel et al., 2023). The goals of these tests were to assess the performance and feasibility of individual subsystems and provide evidence of the complete integration of DSSD technology into an efficient operational control system. The testers were able to mitigate risks with the sub-surface control system and improve their control of the steel-shot injection unit. A detailed description of this testing is described in Knebel et al. (2023).

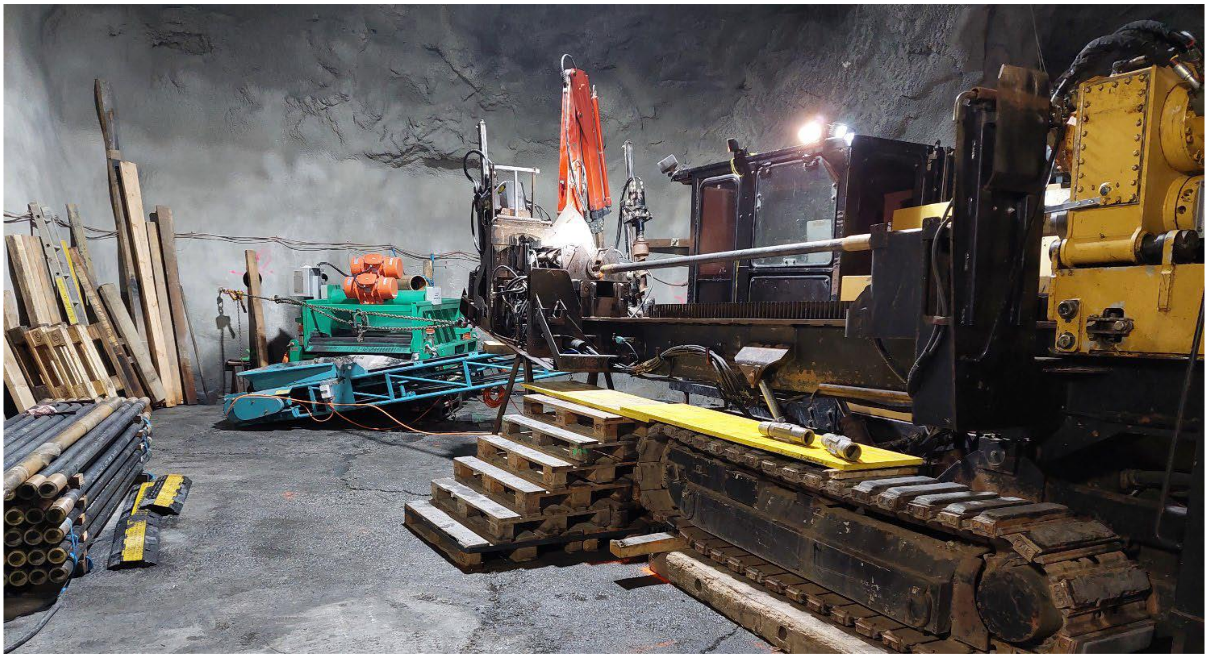

Figure 14 A picture of drilling rig VERMEER 55 in the tunnel at VersuchsStollen Hagerbach (VSH) (Knebel et al., 2023)

The system was then taken to the VersuchsStollen Hagerbach (VSH) gallery tunnel in Switzerland where a horizontal rig was used to drill 2,125 m sections (Figure 14). The testing at VSH demonstrated that the addition of steel shots tripled the drilling speed in soft rock. Despite some challenges, the performance of the downhole control unit met expectations and operators demonstrated that they could adequately clean the hole.

Gaps and challenges for SHR

PD's hardware is not affected by the temperature and pressure of drilling through SHR; however, the injection process needs to be closely monitored when making drill pipe connections. PD's particle impact drilling is market-ready but requires further engineering, bench testing, modelling, and in-field operations to improve performance. Testing at the Utah FORGE site or at a similar open access, hard rock drilling experimental site could accelerate the development of the technology. PD's particle impact drilling is at TRL 5, as it has been run multiple times at full scale in the field but has remaining technology gaps.

Canopus is pushing towards market readiness in 2024 but must perform a full-scale drilling test with a vertical-mounted conventional rig. Its tests thus far have been in soft rock and so it must validate its ROP improvements in hard igneous rock. The system is designed for 6" hole sections (smaller than a typical geothermal well), although the system can be scaled up without much challenge. Full-scale testing with good offset PDC data will provide a good benchmark on performance. Another concern is the Canopus MWD system is an electromagnetic (EM) tool. EM tools have the advantage of no moving parts in the fluid flow; however, they have major signal attenuation problems in deep hard rock and formations with high conductivity. The report from the testing at VSH mentioned signal challenges. EM tools were not used at Utah FORGE due to insufficient signal transfer. Halliburton's negative pulse MWD may be compatible with the Canopus system.

Canopus needs full-scale testing on a commercial project to determine whether the steel shots erode the PDC drill bit. The images of the bit from VSH showed significant erosion, but it is not clear whether that erosion is from the formation or the steel shot (erosion and impact damage were also seen on full-scale tests conducted by PD). The authors of this report believe the modelling and testing that Canopus published on hole cleaning is thorough and the steel shot can be cleaned and circulated out of the hole in horizontal sections. Canopus should form a partnership with one of the leading drill bit manufacturers to conduct advanced fluid dynamics modelling with the inclusion of particles. Canopus's DSSD system is at a TRL level 4 and needs full-scale testing on a commercial project or test rig in hard rock.

4.3 Direct energy methods

Direct energy drilling involves the destruction of rock by exposing it to high-powered energy sources, such as plasma or millimetre-wave (MMW) energy. This focused energy weakens or vaporizes the rock. Cuttings are then cleared by a circulating purge gas or drilling fluid, exposing the next segment of rock to further direct energy, deepening the well. Direct energy drilling systems have several advantages over conventional drilling, including:

- No anticipated complications from SHR or extreme pressures,
- Minimal downhole tools and equipment,
- No/reduced tripping times as there is no/reduced contact of the rock to the drill bit,
- Capacity to transmit energy to depths required of SHR (>5 km), and
- Relatively minimal energy requirements to operate the direct energy system.

Direct energy methods perform best in hard rock conditions. Conventional drilling methods would still be required to drill through the top 2-3 km of sedimentary overburden to reach basement rock before deploying the direct energy system. The process of switching from one drilling system to the next is under development, and further innovation may be required to ensure a conventional rig is compatible with a direct energy rig. Direct energy drilling for rock excavation is relatively novel, therefore, these methods have low TRL statuses: TRL 3-4 for plasma and TRL 2-3 for MMW.

4.3.1 Plasma drilling

The driving mechanism behind plasma drilling technologies is the application of electrical currents through rock formations to create a plasma pulse through the grain boundaries within the rock, which can be achieved by direct contact to the rock interface or while maintaining a stand-off distance (Figure 15). Both methods of plasma drilling rely on an electrical charge to deteriorate the boundary layers as it travels through the rock pores. The performance is dependent on the electrical field of the dielectric drilling fluid and the geological formation on a micro timescale. When the discharge(s) of the pulses are less than 500 ns, the electric field of the fluid is greater than that of the solid rock. The rock deteriorates before the water, resulting in the breakdown of the formation (Q. Zhang et al. 2023). Figure 16 shows the application of plasma drilling to a rock sample using a Zaptec drill bit (Agrawal et al., 2016).

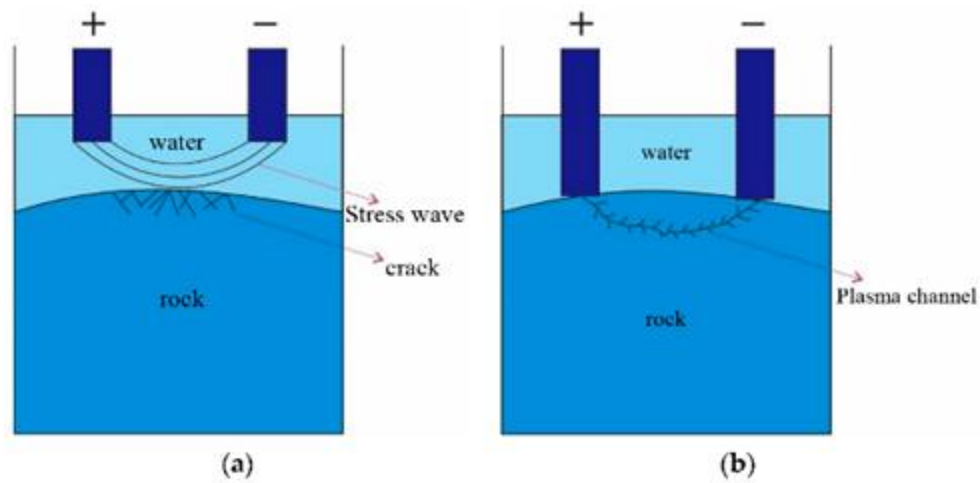

Figure 15 Visual representation of the two different versions of plasma-based fragmentation
(a) non-contact-based wave formation (b) contact-based fragmentation though the formation. (Zhang et al., 2023)

Figure 16 Schematic and real demonstration of plasma drill bit drilling through hard rock (Agrawal et al., 2016).

With a projected consumed energy of 100-200 J/m^3, plasma technology requires roughly 3-5x less energy than conventional drilling systems. The low energy requirements reduce costs by an estimated 17 percent, with the possibility of up to 90 percent reductions with future improvements. Since this method can be completed without the use of conventional drilling bits, the need for WOB is removed.

Slovakia's GA Drilling is on the forefront of the application of plasma systems for geothermal drilling. They designed a system that can be integrated with existing conventional drilling methods (Anchorbit®), as well as a standalone design for ultra-deep depths (Plasmabit®). GA's Plasmabit® system hopes to offer several advantages over conventional systems—namely, increased ROP in hard rock formations, reduction of downtime due to mechanical component wear, and reduction of noise generation and resonance in deeper formations. Testing of

Anchorbit® was completed by ETH Zurich and demonstrated a high ROP of 7.2 m/hr in granite samples. The combination of conventional methods and plasma drilling alleviates the challenges of conventional systems, including tooling wear, tripping time, and low ROP in hard, granite formations. Nabors, who are collaborating with GA on plasma drilling R&D, highlighted the additional challenge of needing to switch out fluid types when switching from a conventional drilling system to drill the sedimentary overburden, to a plasma drilling system for the hard basement rock (Interview with Nabors, February 2024).

According to Liam Lines (Interview, March 2024), GA Technologies is developing another hybrid conventional-plasma system using the shape and geometry of a conventional drill bit with the strategic placement of nodes for the electrical pulses to follow. Through their proposed geometry, the pulsed plasma will weaken the rock surrounding the borehole. By modifying the locations of the cutters, the pulses can interact with the formation, reducing stress and damage on the tooling. This hybrid system is set to be tested in approximately 18 months at Nabors' facility in Texas.

Gaps and challenges for SHR

While plasma drilling technologies show promise for reaching SHR, technology gaps remain. For plasma drilling of hard rock formations (especially granite), the breakdown of the rock formation plays just as critical a role as the technology used to remove the material. The variance within different granite formations plays a significant role in the amount of energy consumed by the drill system and the amount of material removed during each pulse. A recent study (Walsh and Vogler, 2020) shows a significant relationship between the pore size and the amount of total energy consumed during the operation, with implications for ROP and the total required energy to complete the borehole.

While controlled experimentation improves the understanding of these behaviors, larger-scale experimentation is necessary. If the performance of plasma technologies is verified, the overall reduction in required power could be in the range of 100-200 J/m^3 as opposed to the 600-950 J/m^3 required by conventional drilling technologies (Walsh and Vogler, 2020).

Another key factor in the success of plasma drilling is the drilling fluid. Most geological-based laboratory tests use water as the dielectric fluid within the system, but engineers need to better understand how to maintain clean drilling fluid downhole in field conditions. GA's hybrid conventional plasma technology shows the most promise but must overcome the challenge of maintaining clean dielectric fluid and standard drilling fluids. Engineers from Nabors acknowledge this issue requires further work, focusing specifically on where cuttings are removed and difficulties when switching between fluids.

Another focus area for plasma drilling is the delivery of power to the drill bit, which should be considered in the context of the existing directional control systems of drilling platforms. A more seamless integration with current drilling systems could reduce the overall complexity of plasma drilling.

Despite these remaining technical challenges, plasma-based technologies show promise when compared to relying solely on conventional drilling. With reduced overall energy requirements, competitive ROP, and reduced cost due to tooling and time on task, plasma techniques may become a key technology for SHR drilling.

4.3.2 Millimeter wave drilling

Millimeter wave (MMW) drilling is a direct energy drilling method that vaporizes rock by applying intense electromagnetic energy to the rock surface, powered by a gyrotron and transmitted downhole by a metal waveguide. Vaporized debris is excavated from the well by a circulating purge gas. MMW drilling is designed for hard rock conditions such as the crystalline basement, therefore conventional drilling must first be deployed to drill through porous, water-laden sedimentary layers (~3 km). MMW drilling can then be used to penetrate the remaining 7-10 km of basement rock. The primary companies spearheading the R&D of MMW are Quaise Energy (based out of the MIT Plasma Science and Fusion Centre), AltaRock, Advanced Research Projects Agency-Energy (ARPA-E), Oak Ridge National Laboratory (ORNL), and Nabors Industries.

Quaise estimates that MMW could achieve an ROP of 3-5 m/hr with a 1 MW gyrotron for an 8-10" borehole diameter, reaching 10 km in 100 days or less. MMW drilling is a relatively novel technique with a low TRL level and has not yet been field-tested. As of February 2024, the deepest penetrated surface thus far is 2.4 m by 2 cm diameter, performed with a low-powered beam. Research efforts to scale up experiments with a newly acquired gyrotron with 10x the power output and 3x the frequency are underway.

Borehole construction in hard rock with MMW drilling could have several advantages over mechanical drilling methods, namely: no performance limitations due to high downhole temperatures and pressures, minimal downhole equipment (other than a metal waveguide), and automatic borehole reinforcement through rock vitrification (Houde et al., 2021; Oglesby et al., 2014; Woskov & Cohn, 2009). There is no anticipated complication at high temperatures, and vaporization may be more efficient in higher temperatures (Houde et al., 2021).

The MMW energy is supplied by a gyrotron, a vacuum electronic device that generates high-power electromagnetic radiation at up to THz frequencies. The energy induces dielectric excitation at the rock's ablation front that is converted to thermal energy, raising the rock temperature past its vaporization point at over 3,000˚C. To construct a wellbore, the MMW beam is transmitted through a metal waveguide made of a steel alloy with a copper coating, which is continuously lowered into the well. To avoid damage to the waveguide from the high-temperature ablation front, a stand-off distance is maintained between the rock and the waveguide (Figure 17). The edges of the ablation front that are not fully vaporized melt and form a vitrified glass layer (Figure 18). This dramatically reinforces the borehole walls and seals permeable zones from water influx, which may negate the need for well cementation and casing once the well has reached hard, dry rock (Houde et al., 2021; Woskov, 2017).

Monitoring of downhole conditions may be communicated through remote diagnostic signals transmitted down the waveguide. The ablation front temperature is monitored through radiometry, geological properties are measured through exhaust spectroscopy, and the depth to the ablation front is monitored using radar/reflectometry. This information may provide real-time recordings of ROP, downhole dysfunction, plume depth, temperature, waveguide bends, lithology, fluids, and MWW wave mode changes (Oglesby et al., 2014). Information may also be collected through the deployment of downhole sensors (Houderaque et al., 2021; Houde et al., 2021).

Cuttings are removed by a circulating purge gas that conveys sub-mm scale particles from rock debris away from the drilling front by an air drilling system at 100-5,000 psi. Noble gases are optimal as they maintain MMW transmissibility at high pressures, with air used at shallower depths, followed by nitrogen, and then argon at 12-15 km depths where nitrogen and air become supercritical. The purge gas also acts as a downhole cooling mechanism of the waveguide (Houde et al., 2021).

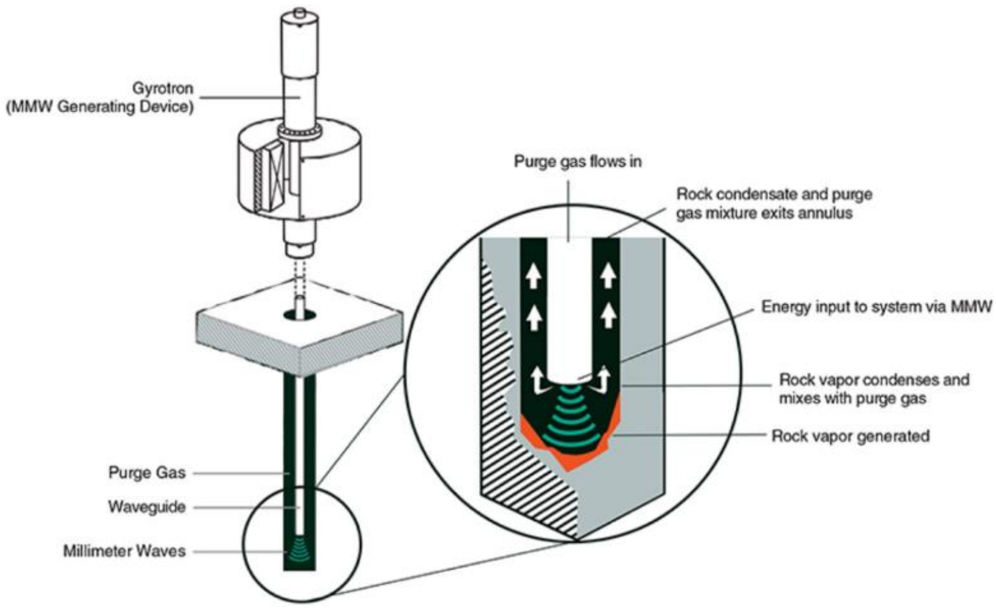

Figure 17 Simplified diagram of gyrotron-powered MMW drilling mechanism (Quaise Energy, 2023)

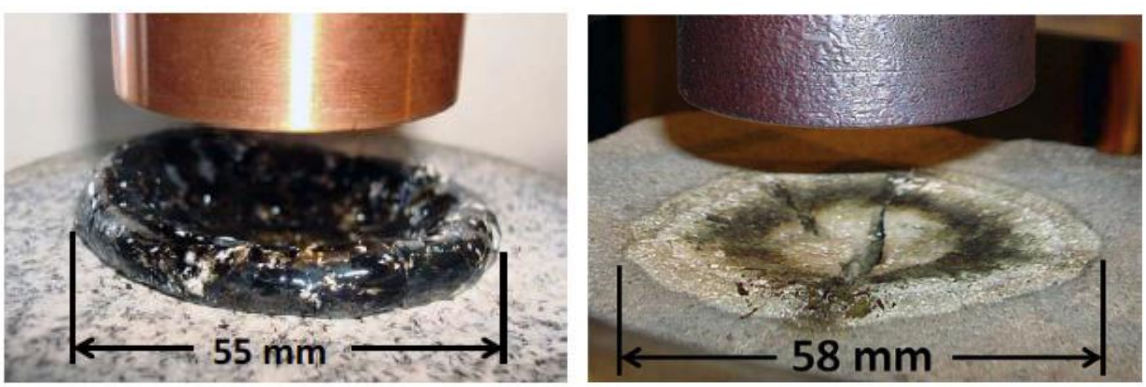

Figure 18 Ablation front, vitrified granite, stand-off distance, copper-steel waveguide (Woskov et al., 2014)

Gaps and challenges for SHR

Experimental scale-up and ruggedization of the gyrotron apparatus are both an immediate focus for MMW-drilling R&D to achieve TRL 5+ levels. Quaise recently acquired two 100 kW gyrotrons and is in the process of securing a 1 MW gyrotron by 2025. The manufacturing rate of gyrotrons globally is between 1-3 years for a single unit, but this could accelerate once the demand increases and with the increased capacity of manufacturing facilities (Woskov & Cohn, 2009). Partnerships with Nabors, AltaRock, ARPA-E, and ORNL will accelerate R&D.

Experimental bench tests at >374˚C have not yet been conducted, as the current research stand is at atmospheric conditions. Acquiring a research stand capable of confining rock samples at supercritical conditions is a first-order technology gap for MMW drilling. Along with bench tests, Quaise, with engineering support from Nabors and ORNL, is in the process of designing a drilling rig that can accommodate the complex gyrotron system to conduct in-situ field tests to achieve TRL 6 status. This rig will be deployed at a field location in Texas in 2024-2025, aiming to penetrate 100-1,000 m (Houde et al., 2021). The rig will be designed to ensure that it can withstand field conditions, namely rough roads to remote areas, and be operated by drilling personnel who are unfamiliar with fusion technologies.

The dielectric absorptive properties of rock in the context of MMW drilling require further analysis through modelling and experimentation. Different rock types will evaporate at different rates depending on their electrical conductivity and absorptive properties (Woskov & Cohn, 2009; Woskov et al., 2014); therefore, MMW drilling through heterogeneous formations may lead to an asymmetrical borehole (Figure 19). However, the uniformly radial shape of the borehole is essential for the continued deployment of the waveguide downhole.

Granite and basalt are the likely rock types to be encountered within deep geothermal settings, yet even within granite, variations in quartz content with low-absorptivity properties can induce heterogeneous vaporization (Zhang et al., 2023). However, the absorptive properties of quartz and other minerals change at high temperatures and in a molten state (Jerby et al., 2005). A greater understanding of these complex processes through numerical and laboratory experimentation is required. These results will be essential in the MMW-drilling process and rig design, as some form of adaptive MMW-energy input may be necessary to cope with the blind changes in lithology downhole that are inherent in a natural setting.

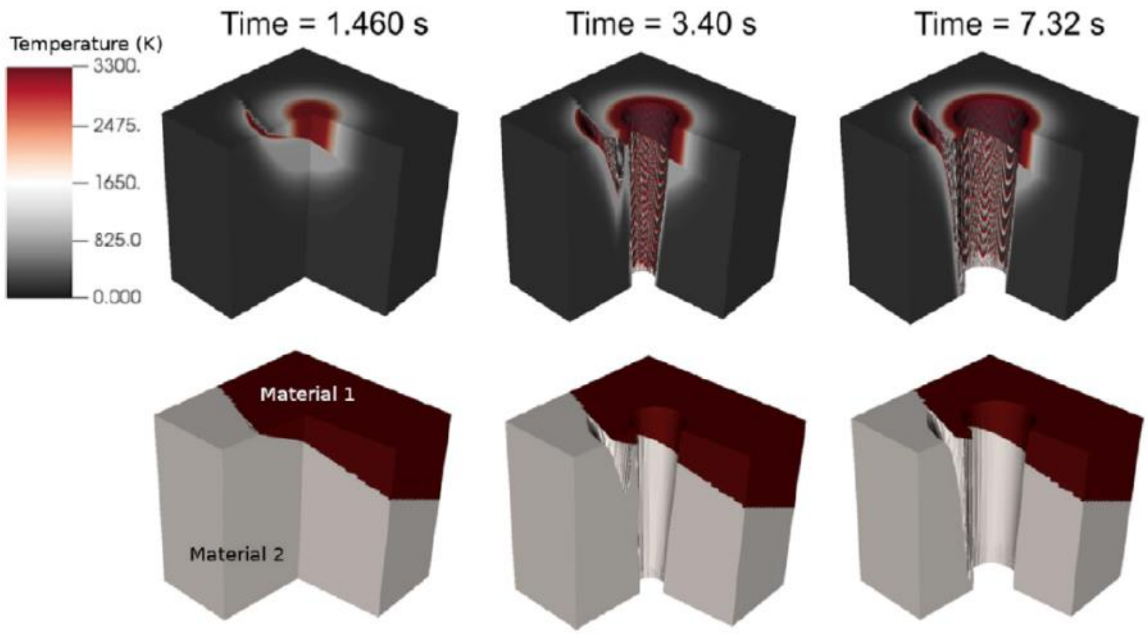

Figure 19 Simulation results for multi-strata with heterogeneous absorptive properties, showing that the vaporization process does not produce a uniformly radial well.
(Zhang et al., 2023)

The waveguide—while simply a metal tube—is a deceivingly complex component of MMW drilling. The waveguide must retain a near-perfect vertical orientation to avoid rapid overheating from the MMW encountering the waveguide. For example, a 30 m bent section of waveguide can heat to over 200˚C in 8 minutes from a 2 MW beam, leading to 10 percent energy losses, damaging the waveguide (steel starts to degrade at 316˚C), and potentially preventing its further deployment downhole (Oglesby et al., 2014). Tortuous or "corkscrew" trajectories commonly seen in conventionally drilled wells may trigger this problem, which could be a considerable challenge for MMW drilling because the proposed drilling program requires conventional drilling for the first 3-5 km of the well.

In the event of waveguide damage, the act of fishing an up to 10 km-long metal pipe from a vitrified well bore is an unknown process and may lead to damage or complete loss of the well. The front of the waveguide must also maintain its stand-off distance from the ablation front, or it will be at risk of overheating above its temperature threshold. The collision of the waveguide on the active ablation front could only be prevented by a highly accurate, real-time downhole monitoring system—one of the active areas of investigation by Quaise.

The wave guide must also be machined to very tight tolerances to maintain a continuous wave to the bottom of the hole. But even if these tolerances can be achieved, the expansion and contraction of the waveguide at different temperatures and pressures seems to be a major challenge. Typically, an EGS project requires two directional wells to be drilled closely together either horizontally or at high angle, which requires significant doglegs to be designed into the well. This type of drilling may be beyond the capabilities of a directional MMW system.

Another challenge is hole stability in an underbalanced condition at great depths—a challenge shared by most deep, hard rock drilling methods. A borehole from MMW drilling can theoretically be strengthened with insert additives/pellets downhole to produce a glass/molten material that can help prevent hole collapse. Another potential solution is to simply redrill the hole, after a collapse event occurs, repeatedly until the surrounding rock relaxes itself to such a degree that there is not enough stress in the near-borehole field to displace rock back into the hole. This may be possible since we do not have drill bits or downhole tools that would get stuck at the bottom of the hole (but this is currently a speculative hypothesis).

Finally, while pore fluids within the rock do not pose a significant challenge to MMW drilling, highly fractured, hydrous media or subterranean caverns will impede MMW transmission. Again, sealing pellets are a potential solution—but this challenge may only be practically resolved through in-situ experiments.

MMW technology is in its infancy and needs a near-full-scale demonstration outside of a laboratory environment to prove its potential. Practicalities in the deployment of the waveguide need to be addressed, including the attenuation of the MMW due to diameter tolerances and expansion/contraction from variations in temperature, pressure, and tensile load. Technology developers need a better understanding of the impact of MMW energy on interbedded heterogeneous formations. They should also calculate and publish the cost per meter of MMW systems.

The primary technology gaps for MMW drilling for SHR include:

- Acquisition of a high-powered (>1 MW) MMW beam to conduct scale-up experiments;
- Access to laboratory facilities with SHR conditions to conduct necessary experimentation;
- Modelling analysis of heterogeneous absorptive properties in rock and the impacts on well shape and ROP;
- Ruggedization of the gyrotron apparatus for in-field conditions and operability by drilling personnel, and adaptations of conventional rig systems for MMW compatibility;
- Proof-of-concept testing of monitoring downhole conditions with radiometry, spectroscopy, and radar;
- Engineering of waveguide deployment and removal, and methods to cope with: downhole bends or tortuosity, and expansion/contraction of the waveguide under different temperatures and pressures;
- Development of directional drilling methods, currently considered to be achieved with a miter mirror; and
- Modelling and in-field testing of well stability in an underbalanced condition.

4.4 Conclusions for rock-destroying equipment

Returning to the three core challenges that rock-destroying equipment must overcome to reach SHR domains (drill to supercritical conditions >374˚C; drill to >5 km through hard rock where most SHR regimes are found; and achieve rapid increases in ROP through hard rock, cutting back drilling time by >50 percent).

Conventional rotary and percussive methods have already overcome one or two of these challenges but no method has conquered all three simultaneously. For example, Fervo and Utah FORGE have demonstrated leaps in

ROP generation through hard rock with PDC bits, however, they did not reach SHR temperatures or depths. IDDP reached supercritical conditions with percussive and rotary drilling. At Stn-1, substantial ROP through hard rock to depths of >5 km was achieved with percussive drilling, but this domain was relatively cold. Many hybrid-conventional drilling methods have reached in-field experimental stages, ranging from a TRL status of 5-7. They should be continually deployed at existing or future SHR projects to conduct necessary performance testing. Primary challenges for advancing both conventional and hybrid-conventional methods to SHR capacity include:

- Limited access to SHR conditions in a controlled setting such as a laboratory bench test may be preventing the iterative improvements required to optimize ROP generation;
- In-field experimentation of each method is needed to advance these technologies for hard, deep, hot rock, to iteratively approach SHR domains;
- Most BHAs are designed with high-temperature ratings, up to 300˚C, although the remaining 75˚C will require further innovation (except Strada Global, which penetrated supercritical domains for IDDP); and
- Coupling MWD and LWD sensors into these specialized drill bits may require further innovation and collaboration between independent drilling firms.

Therefore, the primary gap for mature drilling technologies (conventional rotary and hybrid conventional) to drill to SHR is scaling up experimentation with specialized high-temperature, hard-rock drill bits in SHR conditions or analog EGS field sites.

Scaling up SHR testing will require a coordinated international effort, as SHR analogs are rare, and firms developing high-temperature drilling technology may not reside in the same nations where SHR projects exist. However, deep EGS and SHR projects are gaining momentum, and this research effort can be mobilized relatively quickly once collaborative incentives are in place. Once these high-TRL technologies are actively experimenting in the field, it is possible that one drilling method, or a combination of methods, may be fully optimized for drilling to SHR. However, even with a fully optimal drilling system using a conventional or hybrid conventional approach, these methods may reach a limit. Whether in drill string weight, ROP limitations, or excessive tripping time with deepening wells, mechanical drilling technologies may not be the most effective method to reach SHR in the long term.

Direct energy drilling methods are steadily advancing their R&D programs in the pursuit of SHR geothermal projects. Should they reach commercial scalability, direct energy methods may prove more efficient than mechanical drilling methods due to their minimal downhole equipment, reduced tripping or no need to trip for bit replacement (increasing ROP), >7 km drilling capability, no adverse effects of high temperature on downhole equipment (aside from the MMW waveguide that will experience thermal expansion/contraction), and reduced energy consumption to drill relative to rotary or mechanical methods. These technologies are, however, still at low TRL levels: TRL 3-4 for plasma and TRL 2-3 for MMW. To advance the frontier for direct energy methods to reach SHR domains, both plasma and MMW drilling require:

1. Laboratory controlled bench test at SHR conditions,
2. Ruggedization of direct energy apparatus and system design for drilling rig compatibility,

3. Solutions to deploying downhole equipment (such as the waveguide for MMW drilling),
4. Modelling of the response of rock to direct energy exposure when the rock has heterogenous minerals or properties,
5. Solutions to cleaning the drilling fluid from the borehole after completion of conventional drilling through the first 2 km of soft overburden,
6. Methods to switch from the conventional drilling system to the direct energy drilling system, and
7. Training of operating personnel for direct energy drilling.

This kind of experimentation requires the creation (or adaptation) of laboratory facilities with SHR capacity to bench test these technologies. Such a facility would likely require governmental funding and must be constructed with compatibility with direct energy apparatus and rig design in mind. It must also be internationally accessible. One candidate agency that could receive this funding is Nabors Industries, as they are partners with both GA Drilling and Quaise Energy and are actively working with them on rig design. Nabors also has drill stands at atmospheric conditions, which could possibly be adapted to simulate SHR temperatures and pressures.

In summary, the three drilling categories are at the following frontiers for SHR drilling:

1. Conventional rotary drilling is in the lead but may reach a performance limit,
2. Hybrid conventional drilling may prove superior but requires further experimentation, and
3. Direct energy drilling has long-term potential after significant experimentation and field testing.

5. High-temperature downhole tools: Technology frontier and gap analysis

In geothermal drilling, "downhole tools" refer to the various instruments and devices used in the wellbore to perform operations, gather data, and manage the drilling process. Key components of downhole tools include components of the BHA, which comprises stabilizers, reamers, shock tools, mud motors, rotary steerable systems (RSS), Measurement While Drilling (MWD) tools, and Logging While Drilling (LWD) tools. Additionally, downhole sensors are essential for monitoring and gathering data during the drilling process. The ability for these tools to operate in high-temperature, high-pressure environments is vital to the success of a drilling project.

To achieve a successful well in SHR, downhole tools must withstand high temperatures, and/or the borehole must be cooled to their maximum operating temperature threshold. The temperature limitations of downhole tools must be considered in combination with the technologies and processes discussed in Section 4. If the wellbore can be cooled to below 150˚C, then the system is a TRL 9. However, running 150˚C equipment in the hole would require a full string of insulated drill pipe (IDP). To run a full string of IDP requires a significantly larger rig, a higher-pressure surface system, and greater hoisting capacity. The increase in rig size and the additional cost of the IDP may incur costs that make the SHR project uneconomic.
The most cost-effective solution is a combination of high-temperature downhole tools and technologies from Section 6 (temperature management equipment). Even if the borehole is cooled to below 150˚C (normal O&G electronic tool operating temperature), a significant temperature safety margin must be maintained for connections, loss of circulation, surface equipment failures, and "staging in." Staging in is the process of deploying the BHA and drill pipe into the hole and circulating fluid to cool the borehole. This process incurs invisible lost time (ILT) and adds significant cost to an operation—a phenomenon that was observed at FORGE when drilling the deepest section of the well.

Pressure limitations of most high-temperature tools are in the range of 25,000-30,000 psi, which is within the range of SHR wells. Due to low mud weight, SHR geothermal wells will likely have bottom hole pressures under 20,000 psi. The main limitation of these tools is the maximum temperature rating of the elastomers in the pressure seals. Viton rubber seals have a max temperature of 300ºC and Tetrafluoroethylene O-Rings 232ºC.

High-temperature tool limitations are currently around 175ºC to 200ºC, and several companies are striving for temperatures >210ºC. Recent technology demonstrations at the Lincoln Laboratory at MIT showed that the temperature limitation for electronic components could be cost-effectively raised to 300ºC.

One major challenge for high-temperature downhole tools is power supply. The maximum operating temperature of downhole battery packs is 200ºC. This limitation can be overcome with a downhole turbine that provides power to the tool. High-temperature electric motors for downhole turbines with non-organic insulation are achieving higher temperature ratings (also demonstrated at the Lincoln Laboratory). A turbine can cause problems for measurements that require a continuous supply of power.

5.1 High-temperature tool manufacturers

Hephae: PandoraX and RSS (225^{o}C)

Hephae is a startup operated by former employees of major service companies and downhole tool manufacturers. Their near-term focus is on 210^{o}C tools, with aspirations for increasingly higher temperatures. Hephae is designing and building an MWD called PandoraX and a rotary steerable system (RSS) that is modularized and can be linked to their PandoraX platform (Figure 20).

The use of high-temperature (>210^{o}C) RSSs will be pivotal to drilling SHR, as developers will need greater precision and better real-time data from MWD tools. For example, adding a mud motor to the bottom of the drilling system often creates RPMs that are too high for optimal depth of cut. The pressure losses through the motor indicate that flow rates need to be lowered, in turn reducing the amount of fluid available for cooling. Further, rubber components in mud motors lower the maximum operating temperature and reliability of the combined drilling system. According to John Clegg at Hephae (Interview March 2024), the high-temperature RSS allows full directional capability with continuous rotation, which improves hole cleaning and reduces the risk of the BHA getting stuck downhole.

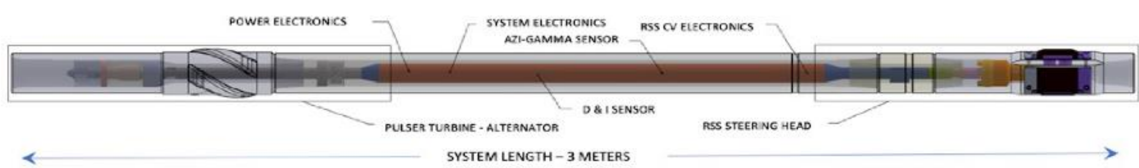

Figure 20 Picture of Hephae's high-temperature integrated MWD and RSS.
(Hephae, 2024)

In Section 6 (temperature management equipment) we conclude that even if an IDP was available for a high-temperature project, there would be significant commercial and technological advantages to running the IDP in conjunction with >210^{o}C downhole tools, which could reduce the amount of IDP by around 50 percent, lower the string weight, and improve hydraulics. The estimated premium of IDP over regular drill pipe is roughly $6,000 (all costs in this paper are USD) per joint. If a developer can run 210-250^{o}C tools and reduce the amount of IDP by 50 percent in a 25,000 ft well, savings on capital costs would be around $2.5 million per well. Another major cost to SHR geothermal is the rig time spent circulating and cooling the wellbore while running back to bottom. Combining high-temperature tools with a 50 percent insulated string and low heat coefficient coated drill pipe could reduce trip costs by USD $50,000-$100,000 a trip.

NOV: Hellfire (175^{o}C)

NOV have developed a range of high temperature tools, including the Tolteq™ iSeries and the Tolteq™ Hellfire. These tools go through a rigorous temperature qualification process, cycling the temperature on the tool from 25°C to 175°C for 1,000 hrs. The Tolteq™ iSeries platform is the leading probe-based, mud pulse MWD available in the independent directional drilling market. As a modular platform based on the legacy Tensor design, the iSeries platform provides significant flexibility to configure and deploy the tools in a wide variety of applications. According to Anthony Dukowski and Paul Neil of NOV (Interview Feb. 2024), the NOV Tolteq™ tool range is well-suited for geothermal operations in remote locations. One of the advantages of running probe-based tools into the well is that if temperatures start to become too hot or the string gets stuck, a wireline can be run into the hole to retrieve the tools, reducing lost-in-hole costs.

Weatherford: Heatwave (200°C)

The Weatherford Heatwave tools provide a 200°C-rated "triple combo" LWD/MWD service. These tools—used in combination with IDP, mud coolers, and low heat coefficient coatings—can operate in SHR formations up to 400°C.

Gunnar Energy Services (370˚C)

Gunnar Energy Services is actively pursuing advancements in high-heat drilling, particularly for active and passive magnetic ranging technologies. The technology has been proven to be effective up to 220°C for Steam Assisted Gravity Drainage wells but is restricted by the heat tolerance of MWD sensors. The potential to adapt these ranging methods to operate at SHR temperatures is a significant technological challenge. To achieve this, Gunnar plans to develop pipe and active ranging solenoid components with ceramic coatings designed to withstand extreme heat. While the theoretical foundations for these adaptations are established, they require comprehensive testing to understand how supercritical heat affects magnetic signatures in controlled laboratory environments and real-world field trials.

Halliburton: Solar (175°C) and Quasar (200°C)

According to Andrew Penman and Matt Holdeman Halliburton (Interview, February 2024), Halliburton has done extensive development on high-temperature tools, with one line rated at 175°C (Solar®) and another at 200°C (Quasar®). Their maximum operating temperature and pressure is summarized in Table 1. The Quasar® line of tools have a high temperature rating but were designed for high-temperature oil and gas wells. The diameter of the Quasar® tools is not suitable for SHR geothermal, as they are too slim for 8 ½" hole sections.

Tool/Sensors	Maximum Operation Pressure (psi) & Temperature (°C)							
	9½"		8"		6¾"		4¾"	
Rotary Steerable	30,000	175	30,000	175	30,000	175	30,000	175
Directional	30,000	175	30,000	175	30,000	200	30,000	200
PWD	30,000	175	30,000	175	30,000	200	30,000	200
Gamma	30,000	175	30,000	175	30,000	200	30,000	200
Resistivity	30,000	175	30,000	175	30,000	175	25,000	200
Density	25,000[1]	150	30,000	175	30,000	175	25,000	200
Neutron			30,000	175	30,000	175	25,000	200
Sonic	25,000	175	30,000	175	30,000	175	30,000	175
Formation Tester	30,000	175	30,000	175	30,000	175	25,000	150
DrillDOC® Collar	25,000	175	30,000	175	30,000	175	25,000	175

Table 1 Halliburton's high-temperature tools.
(Halliburton, 2024)

Directional wells require both measurement tools and a drive system. Halliburton is developing motors with high-temperature elastomers rated up to 188°C, and an RSS rated up to 175°C and 30,000 psi. For the well-on-well connections necessary for drilling a closed-loop SHR well, Halliburton's rotary magnetic tools (rated to 175°C) could be combined with other temperature management equipment to work at 400°C.

Baker Hughes (175˚C)

Baker Hughes has designed a drilling system to cope with 300˚C temperatures at 10 km depths in hard rock for a minimum of 50 on-bottom hours specifically for SHR. The system includes an MWD, drill bit, steerable drilling motor, and drilling fluid for an 8 ½" borehole (see Stefánsson et al. 2018 for the complete review of the system, including its performance at IDDP-2).

Figure 21 A conventional positive displacement drilling system.
(Baker Hughes, 2023)

Deep directional drilling requires positive displacement motors (PDM), that include a "drive sub" that connects to the bit, an adjustable kick-off that enables bending in the drilling system, and a power section (Figure 21). A point of weakness in conventional PDMs is the elastomer sealing that line the stators, which are rated to 190˚C.

Baker Hughes has implemented full metal stators in their high-temperature drilling system, referred to as the metal-to-metal (M2M) motors, that are composed solely of steel alloys with a mud-lubricated assembly and are rated up to 300˚C. The rotor and stator are elastomer-free with a wear-protection coating that protects the metal-to-metal contact points. One drawback is the potential for fluid leakage between the rotor and stator without the elastomer sealing; however, a fully sealed chamber could be engineered with further R&D. In-field and laboratory experiments proved that high torque outputs can be maintained at temperatures over 250˚C for over 50 hours, with an anticipated drop in rotational speed from 80-50 RPM throughout the drilling run (Stefánsson et al. 2018).

Downhole MWD and LWD instruments contain electronics that cannot withstand SHR temperatures. Rather than developing costly electronic tools with higher-temperature ratings, Baker Hughes developed a cooling system for their BHA to maintain internal temperatures at 175˚C, even under 300˚C conditions. According to John Macpherson (Interview, 2024), Baker Hughes' cooling system capitalizes on the evaporative properties of water and isolates the temperature of the thermos flask containing the electronics through a control valve.

MB Century (350°C)

While drilling and completing an SHR well, it may be necessary to run tools into the wellbore to log the temperature, casing quality, and cement quality. Logs can also be run regularly to understand how the well is changing due to thermal cycling and corrosion. According to Greg Thompson (Interview, 2024) MB Century's tools have specifications very close to SHR conditions. Logs can also be run regularly to understand how the well is changing due to thermal cycling and corrosion.

Schlumberger: TeleScope ICE and PowerDrive ICE (200°C)

Schlumberger has developed an MWD and an RSS for 200°C. The TeleScope ICE (MWD) and the PowerDrive ICE (RSS) tools have both been tested for 2,000 hours at 200°C. Both tools have integrated ceramic electronics (ICE) and multichip modules designed specifically for high-temperature environments. These tools are collar-based, and unlike the probe-based tools, they are not retrievable if the wellbore temperatures get too high or the assembly gets stuck in the hole.

Gaps and challenges for SHR

The temperature limitation for most downhole tools is within 175-200°C, with some tool manufacturers reaching 220°C in their pursuit of SHR. The most cost-effective and market-ready approach is to deploy existing high-temperature tools in a well cooled to the operable temperature with the equipment discussed in Section 6. The combination of these methods is at TRL 9. Technology companies must continue to improve high-temperature-resistant electronics with non-organic materials (such as all-metal seals) and develop high-temperature-resistant capsules for electronics. Further research into "one run" tools that are deployed once before expiring from high temperatures may provide a cost-effective (but potentially wasteful) alternative to engineering SHR-capable tools or deploying temperature management equipment in combination with existing high-temperature tools.

5.2 High-temperature motors

Several publications and papers (e.g., Stefánsson et al., 2021; Epplin, 2015) discuss the use of mud motors with metal-on-metal power sections. These motors all appear to have a temperature rating of around 300°C. Based on discussions with various groups deploying these motors, the authors conclude that challenges remain in machining the steel parts within the required tight tolerances—and, even when those tolerances are met, the motors can be susceptible to erosion by particles in the drilling fluid.

Gaps and challenges for SHR

High-temperature motor technology is at TRL 6 and requires further investment, field testing, and ruggedization to reach TRL 9. If a drill string is designed to cool the well to 175°C (the current limit of electronic tools), it may prove unnecessary to develop motors that reach 300°C. In that case, operators can opt for high-temperature, even-wall rubber motors rated to 190°C.

5.3 Conclusions

No high-temperature sensors are rated for SHR. The practicality of building tools to survive in well temperatures of >374°C without the use of any temperature management systems would require significant scientific breakthroughs. The National Renewable Energy Lab and NOV spent a year investigating 374°C electronics to determine if it was possible to design tool components using packaged aluminum gallium nitride/gallium nitride (high electron mobility transistors are used in high-frequency and high-power switching applications). This study showed that, even if chipsets could be built with this compound, the batteries and other components remained a limitation (based on the experience of the lead author at NOV).

The consensus of equipment manufacturers is that electronics will only withstand SHR conditions with a combination of the highest-temperature-rated tools and a cost-effective temperature management system. As described in the next section, managing the temperature of the borehole to below 175°C is achievable today, but temperature management equipment requires further testing and validation in SHR conditions. Therefore, the TRL of high-temperature sensors in SHR conditions is TRL 8 when used with other cooling methods, TRL 7 if encapsulated, and TRL 3 for stand-alone tools.

6. Temperature management equipment: Technology frontier and gap analysis

When drilling fluid gets too hot, its ability to carry the drilled cuttings deteriorates, bit wear increases, downhole tools are destroyed, and the risk of drill pipe and casing corrosion increases by orders of magnitude. Overheated drilling fluids also prevent the use of downhole motors and electronic instrumentation and can affect borehole stability and well control. Each of these consequences can be countered by individual technology developments, but all can be solved (or greatly mitigated) by simply cooling the downhole environment.

Temperature management can be achieved with a combination of equipment, including low-heat coefficient coatings, mud coolers, and (most significantly) insulated drill pipe (IDP). Current drilling technologies can be used in 400˚C rock; however, to do this economically, a combination of technologies must be deployed. For example, the combination of high-temperature tools with low-heat coefficient coatings and mud coolers decreases the amount of IDP needed, lowering daily operating costs. IDP generally has a smaller inner diameter and is significantly heavier than traditional drill pipe. The rig would thus require higher-pressure-rated pumps and standpipe, a stronger derrick, a stronger substructure, and draw works with a higher lifting capacity. This increased rig capability would enable the SHR well to be drilled but at a significantly higher cost.

An alternative method to managing borehole temperature is to drill with CO_2 in its various states: gaseous, liquid, and supercritical fluid (sCO_2). sCO_2 has a similar density to a liquid and a viscosity comparable to a gas. The sCO_2 can be used as a drilling fluid to keep the drilling tools cool, and its density could power downhole mud motors and RSS. The downhole pressure and temperature domain would hold the CO_2 in a supercritical state on the journey down the drill pipe or coiled tubing, and it would convert to vapour when exiting the drill bit nozzles. With the CO_2 in a vapourized state, the borehole annulus will be in an underbalanced condition, therefore less likely to lose circulation (a common problem in geothermal wells, especially wells in basement rock with a high fracture density).

A core challenge with using CO_2 as a drilling fluid is its availability in a concentrated supply. One O&G operator that drilled several CO_2 wells in Louisiana managed to source CO_2 at a volume and price required for enhanced oil recovery, but these resources are in very limited supply. Significant advances in carbon capture and a reduction in cost are required to scale up CO_2 drilling.

6.1 Insulated drill pipe

Thermal and mechanical analyses on insulated drill pipe (IDP) were first conducted at the Sandia National Laboratories in the 1980s but the concept remained relatively dormant for nearly 20 years. In 2000, Drill Cool Systems built three joints of prototype IDP, conducted preliminary tests to evaluate the effective thermal conductivity of the pipe, and ran these joints in field operations. In a collaboration with the Geothermal Drilling Organization, they constructed a complete string of pipe (5500’) and tested it in Imperial Valley in California (see Champness, 2000).

There are three basic approaches to IDP. The advantages and disadvantages of these approaches were defined well by the Sandia team in 2000 and are summarized in Table 2 below.

Fabrication Method	Advantages	Disadvantages
Single-wall, insulation inside	Light weight; insulation protected from abrasion wear and impact with casing or wellbore; minimum erosion from cuttings, could insulate tool joints.	Failed insulation could plug bit or downhole motor; difficult to install, repair, or replace insulation; requires tough, strong insulation.
Single-wall, insulation outside	Light-weight; insulation easy to apply; insulation failure would not have serious effect on circulation.	Insulation vulnerable to erosion and impact; probably could not insulate tool joints or pipe handling areas of pipe body; requires tough, strong insulation.
Double-wall	Excellent insulation properties, rugged design that could handle tough drilling conditions. Reliable protection for insulation; no strength (except compressive) or toughness requirement on insulation. Insulation material development not required.	Pipe is heavy: fabrication is complex and expensive. The reduced inside diameter affects hydraulics.

Table 2 Fabrication methods for IDP (adapted from Champness, 2000).

Several recent studies have investigated the effectiveness and potential of IDP in SHR applications. (Ajima, K., Naganawa, S., 2022; Pink et al., 2023). The study by Ajima and Naganawa modelled the use of IDP in a 4,000 m well with a max temperature of 600˚C. They used the base pipe design from Sandia and Drill Cool and GEOTEMP2 software. The model showed that a full string of IDP could deliver sub-175˚C fluid at 4,000 m under supercritical conditions.

When they investigated the effects of running a half string of IDP (flowing at 2,000 L/min), the temperatures were 209.6˚C (upper half of IDP) and 233˚C (lower half of IDP) at 4,000 m. Both temperatures are higher than the normal operating temperatures of electronic tools. However, there was a significant effect when the flow rate was increased from 2,000 L/min to 3,000 L/min. At 3,000 L/min, the bottom hole temperatures were lowered to 132˚C (upper half of IDP) and 159˚C (lower half of IDP). These results are depicted in Figure 22 and summarized in Table 3.

	1500 (L/min)	2000 (L/min)	2500 (L/min)	3000 (L/min)
Upper Half (˚C)	280.2	209.6	163.0	132.0
Lower Half (˚C)	286.9	233.6	191.6	159.8

Table 3 Bottom hole temperature for different mud circulation flow rates in a partial (1/2) IDP application (adapted from Ajima et al., 2022).

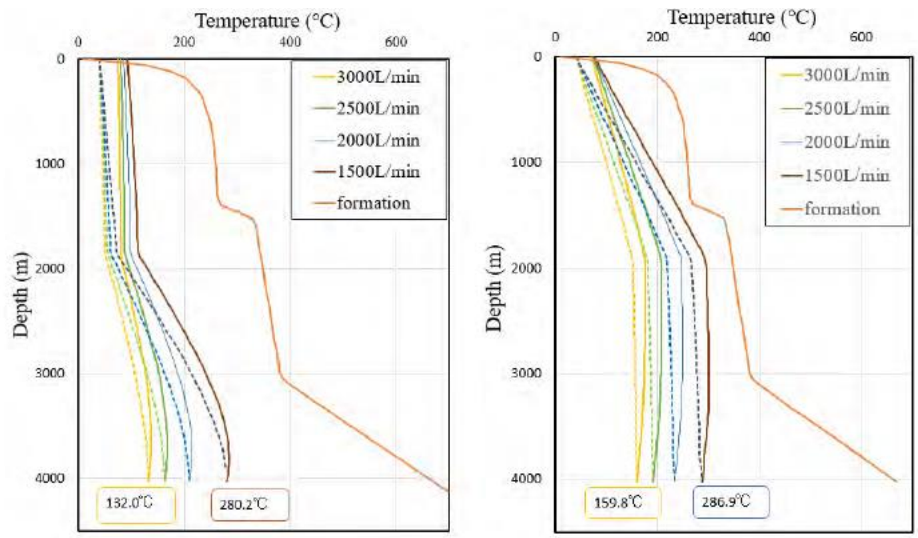

Figure 22 Temperature profiles when applying IDPs along (Left) the upper half of the wellbore and (Right) the lower half of the wellbore with drilling mud.
(Ajima et al., GRC 2022)

In 2022, NOV investigated the limitations of the original Sandia and Drill Cool IDP designs. They focused on two areas: (1) applying low heat coefficient coatings to the internal diameter (ID) of normal drill pipe and (2) designing, modeling, and building a string of IDP that did not have the ID limitations of the Sandia-designed pipe (3”).

The NOV team presented their progress on IDP designs at the Society of Petroleum Engineers conference in Stavanger in 2023. Their IDP consisted of a unique thread form in the box end of the connection (Figure 23) that enabled a 4” rubber-coated inner tube to be pressed into the drill pipe body. The ID of the NOV IDP is 3.69”, significantly larger than the original 3.0” design. The NOV team also reported that the thermal conductivity of the pipe could be lowered significantly by applying a low heat coefficient coating to the inside of the tool joints, removing some steel from the inside of the tool joints and replacing it with Inconel or stainless steel, and using range 3 pipe (therefore 30 percent fewer tool joints in the string). Lastly, they highlighted the effect of heat capacity of mud versus water. If mud is replaced with water (which has a lower specific heat capacity), the bottom hole temperatures are higher.

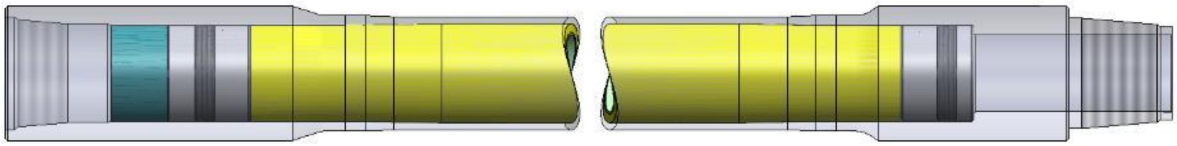

Figure 23 IDP design from NOV that allows an inner diameter of 3.69" inside a 5 7/8" drill pipe tube.
(Pink et al., 2023)

In the IDP design above, the whole of the IDP string is coated with a low heat coefficient coating provided by a division of NOV called Tuboscope. It is additionally important to consider the effect of heat capacity on mud and water. In its current form, IDP is heavy, relatively expensive (roughly 2-3x the cost of regular drill pipe), and has high pressure losses—placing higher demands on pump pressure capability, the strength of the derrick and the substructure, and the lifting capability of the draw works. However, running IDP and cooling the fluid to maintain surface temperatures below 100˚C would have a significant positive impact on the cost of other rig equipment and would eliminate the need for high-temperature elastomers.

Gaps and challenges to SHR

Looking at the drill string (not including mud coolers and mud properties), it is the opinion of the authors that the currently available IDP technology combined with coated regular drill pipe can deliver sub-175˚C fluid to the bottom of a 7,000-8,000 m well in SHR conditions. Operators should look for the lowest-cost, highest-value combination of coated pipe, IDP, and high-temperature downhole tools (along with a surface rig that delivers the optimum flow rate with sufficient hoisting capacity). If the IDP drill string is too heavy, higher -temperature-rated tools could be run and/or surface mud coolers could be added to the system.

Recent modeling shows that there are no major technology gaps to managing the temperature of a 400˚C SHR well below 175˚C while drilling (Pink et al., 2023). However, the technology must be manufactured, and a full-scale pilot project must be drilled at SHR conditions to validate the technology and ensure that it is field-hardened for the downhole conditions. The complete drilling system must be modelled prior to in-field testing to ensure the most cost-effective solution is selected. Drill Cool has a market ready product (TRL 8) and NOV has a design built on a platform of known technology but requires a project and customer (TRL 6).

Titanium drill pipe

Titanium is well-established in aerospace, marine, and defense industries for its outstanding performance in environments above 500˚C. The metal's low thermal conductivity insulates drilling fluids within the pipe from extreme external heat to maintain lower temperatures within the pipe and increase drilling efficiency. When paired with low heat coefficient coatings, titanium drill pipe can further reduce thermal transfer, boosting drilling rates by promoting temperature-induced fracturing at the bit face.

5″ Titanium Drill Pipe 47°/100 feet
Rotating Fatigue Tested to over 1 Million Cycles
©2024 ALTISS Technologies, Sugar Land, Texas

6.625″ Titanium Drill Pipe Qualification Testing
Tension Rating – 3MM lbf. Plus. U.S.A. Patented
©2024 ALTISS Technologies, Sugar Land, Texas

Figure 24 Images of titanium drill pipe from ALTISS Technologies.
(ALTISS Technologies, 2024)

Titanium's excellent strength-to-weight ratio enables the production of lighter yet stronger drill pipe and well tubulars. This reduction in weight improves the depth capabilities of drilling rigs, broadens rig selection and options to control rig move costs, and reduces the footprint of drilling pads. Further, titanium's superb corrosion resistance and thermal stability at temperatures up to 500˚C ensures the long-term durability of tubulars and downhole equipment in harsh conditions with far longer life cycles than stainless chrome and nickel alloys. These longer life cycles significantly decrease the need for maintenance and replacement in severe downhole conditions.

Titanium also exhibits superior fatigue resistance and dimensional stability, crucial for maintaining structural integrity during severe thermal cycling. This property makes it particularly suitable for scenarios with frequent temperature fluctuations, effectively preventing fatigue cracks and deformations that could lead to system failures.

ALTISS Technologies is at the forefront of titanium drill pipe designed for hostile geothermal conditions, including SHR conditions. Their patented titanium drill pipe (Figure 24) dampens vibrations to enhance mechanical energy efficiency, leading to higher penetration rates and extending the life of the BHA and drill string. In addition to drill pipe, ALTISS is applying titanium to other components, including drilling and completion systems components, casing, and tubing. This underscores titanium's growing importance and ongoing improvements in high-performance applications.

Gaps and challenges for SHR

The cost of titanium drill pipe is the biggest challenge for scaling the technology. Testing alternative alloys, metals and coating solutions should be prioritized for SHR development. If costs can be brought down, titanium drill pipe would be at TRL 9.

6.2 Drilling fluid

6.2.1 Water-based fluid

Drilling fluid maintains downhole drilling temperatures and mud stability, suspends cuttings, and protects the wellbore. These functions are essential in geothermal domains where the borehole is at risk of thermal and structural instability, circulation losses, and high frictional resistance (Petty et al. 2020; Song et al. 2023). The fluid requires enough viscosity to form a "wall cake" along the borehole surface to prevent fluid losses, typically achieved with biopolymers in conventional drilling (which are only rated to <149˚C) (Petty et al. 2020). Most geothermal muds are a mixture of fresh water and bentonite clay, with polymers added to improve mud viscosity and filtration properties. Aerated muds may also reduce circulation losses in geothermal settings (Song et al. 2023).

From a purely temperature management point of view, running a mud with a higher specific heat capacity than water would be beneficial; however, data from FORGE has shown that drilling with water with little or no additives has a significant positive effect on ROP. The volatility and chemistry of drilling mud under high pressure and temperature conditions are key factors. High temperatures may induce the flocculation (i.e., clustering) of bentonite dispersion and degrade mud chemistry and viscosity, leading to filtration loss, reduced cutting suspension and transport, and, ultimately, compromised borehole stability. The inclination and depths of geothermal wells may increase frictional resistance, further compromising cutting transport. Interbedded formations found at geothermal sites may also result in heterogeneous pressure distribution downhole and high brine content may impact mud density and chemistry (Song et al. 2023).

To compensate for these risks, geothermal projects use additives to improve well stability, such as sulfonated asphalt powder, sulfonated lignite, and sulfonated phenolic resin. For example, MAGCOBAR's high-temperature drilling mud, DURATHERM (a water-based mixture of clays, resins, and lignite) was used to drill a 3,200 m deep, 353˚C geothermal well at the Salton Sea. The German Continental Deep Drilling Programme (KTB) also developed a silicate compound called Dehydrill HT with 280˚C rheological stability that can enhance drilling mud.

Synthetic polymers <204˚C can be added to the drilling mud, as well as clay-based drilling fluids such as Halliburton's ilmenite-based Microdense™ mud system used at Larderello for the project DESCRAMBLE (Petty et al. 2020). The mud for the IDDP-2 well was rated up to 300˚C and remained stable after 50 hours of use (Figure 25) (Stefánsson et al. 2018). This mud was water-based, with a bentonite stabilizer and low molecular weight copolymer additives and vinyl-sulfonated copolymers (Petty et al. 2020). Additional lubricants were required to maintain the elastomer-free MWD deployed at this site (Stefánsson et al. 2018). Finally, Baker Hughes has developed 260˚C rated viscosifiers, thinners, deflocculants, and filtration reducers that can be added to bentonite slurries (Song et al. 2023).

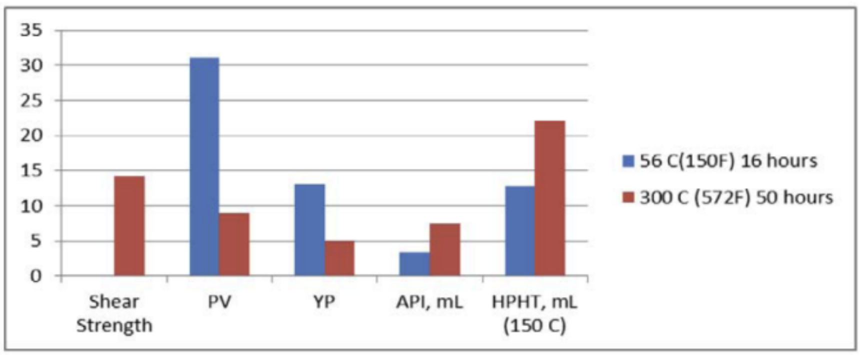

Figure 25 Drilling fluid shear strength [lbf/100ft2], plastic viscosity (PV) [cp], yield point (YP) [lbf/100ft2] after exposure to 56˚C and 300˚C (Stefánsson et al., 2018)

In geothermal well construction, maintaining wellbore stability requires drilling fluid with high thermal stability and better rheological properties. Commonly used water-based muds and additives experience common problems, such as lost circulation, wellbore cleaning, hydraulics, and fluid stability (Mohamed et al., 2021). Lost circulation is the most frequently encountered, time-consuming, and costly problem faced during hydrothermal well drilling. As the geothermal resources are in the fractures and fissures, lost circulation is expected as the target depth is reached or whenever fractures are encountered.

The first step to combat this issue is to stop drilling and circulate the lost circulation materials. If the issue is still not resolved, the next step is plugback cementing. The time required to resolve lost circulation issues is counted as Non-Productive Time (NPT). In wells analyzed by Visser et al. (2018), the NPT due to lost circulation was as high as 197 hours (8 days). Lost circulation accounts for 85 percent of the total NPT for some geothermal wells. The cost of the project is highly affected by the time required to mitigate the lost circulation issue and the method and materials used for mitigation.

Lost circulation risks can be significantly reduced by not drilling fractured basement rock and instead focusing on SHR in dry conditions and then creating a fracture network after the well has been drilled. Hydrothermal wells are designed to intersect natural fractures. By switching to an enhanced geothermal system (EGS) or closed-loop geothermal (CLG) design, the well can avoid natural fractures and reduce the risk of lost circulation.

Gaps and challenges for SHR

Water, at the correct fluid velocity, is sufficient to clean the hole if developers maintain the borehole inclination below 20 degrees. Above 20 degrees inclination, research is needed in high-temperature additives that would provide adequate rheology to clean the hole, especially if operators begin drilling horizontal SHR wells. R&D in high-temperature fluids could be conducted by national labs and universities in partnership with a commercial entity who can test the technology. Advanced testing equipment that can perform a full set of mud tests at 400˚C probably does not exist and needs to be designed and built. Drilling fluids in SHR conditions below 20 degrees inclination have a TRL of 8 or 9, and more complex high-temperature mud systems for wells above 20 degrees inclination are at a TRL of 4 or 5.

6.2.2 CO_2-based fluid

To use of supercritical CO_2 (sCO_2) as a drilling fluid—which is distinct from using sCO_2 as a geothermal working fluid—several modifications are required to make the system compatible with a conventional rig. The sCO_2 would be injected at the surface into the drill pipe and the supercritical state would be maintained by controlling the flow rate and the operating pressure of the system. Such a system would be comparable to a conventionally managed pressure drilling system that is used on operations where the reservoir is under-pressured and cannot be drilled with normal mud weights. The pressure drop of the system would be dictated by the pressure drop of the drill string, the downhole tools, and (primarily) the drill bit. The sCO_2 would have sufficient density and provide sufficient hydraulic power to drive the downhole tools and provide a medium for the tools to transmit a signal back to the surface. As the sCO_2 exits the nozzles in the drill bit, it changes state from a dense sCO_2 phase to a gaseous phase, causing a significant drop in pressure and temperature at the drill bit and rock interface. This drop in temperature and pressure creates thermal impact on the formation, especially if the differential between the formation temperature and the drilling fluid temperature is >100˚C (Phuoc et al., 2020). This thermal impact weakens the crystal structure at the basement rock and bit interface, improving drilling efficiency.

As the sCO_2 changes phase to a gas, it provides adequate annular velocity to clean the cuttings out of the hole. Gaseous CO_2 would also insulate the sCO_2 in the drill pipe from the formation temperature, provide an underbalanced condition in the annulus, and minimize the risk of lost circulation should there be any permeability or large natural fractures.

The primary benefits of using sCO_2 as a drilling fluid are: the ability to cool the drilling system so conventional or high-temperature rated tools could be run in combination with the sCO_2 system, the lower annular pressures which significantly reduce the risk of lost circulation in naturally fractured formations, and potential increases in ROP from the thermal impact of hitting SHR with sCO2. The primary disadvantages and complications of running a sCO_2 system are: sourcing a sufficient amount of sCO_2, the environmental impact of potential leaks, and the need for crewmembers with experience drilling with sCO_2.

Gaps and challenges for SHR

All the components of a sCO_2 system exist, but the complete system needs to be engineered and fully integrated into a package that includes all the mechanical hardware, a control system, a model, and trained experts to run it—and then that package must be tested in the field. With the right level of investment, this package could be realistically developed and tested in 2-3 years. The TRL level for CO_2-based fluid is 3, but this could quickly move to a TRL 7. However, CO_2 production needs to increase to scale up this technology.

6.2.3 Optimizing fluid dynamics

An engineered system that optimizes the fluid dynamics may further enhance the cooling mechanisms employed in an SHR well. Fluid dynamics optimization is achieved with an accurate well design, particularly regarding hole size and drill pipe to deliver the optimum volume of cooling fluid to the drill bit. If a state of laminar flow can be created in the annulus, then significantly less heat would be transferred from the hot formation to the drilling fluid. The laminar flow effectively creates a layer of fluid close to the borehole wall that insulates the fluid. If turbulent flow occurs, this layer would be destroyed, and the fluid would warm up significantly.

The well must be modelled prior to design phase and that model should be run in real-time to ensure that the annulus is in laminar flow whilst drilling. With particular designs and flow rates, laminar flow may not be possible. This technique would typically be used with other cooling methods, such as insulated pipe and mud coolers.

Gaps and challenges to SHR

The TRL status for fluid dynamics optimization is 9, as the technology and physics are fully understood today. Fluid dynamics optimization is a complementary process that enhances the new well-construction technologies being developed.

6.2.4 Low heat coefficient coatings

Before the development of low heat coefficient coatings, previous coatings had an average thermal conductivity of 0.8360 W/mK, which is much lower than carbon steel (45 W/mK). Through iterative formulation adjustments, NOV, in collaboration with Eavor, has developed a coating formulation with an average conductivity of just 0.1808 W/mK, well below the conventional coating value and the operator's target (Figure 26 and 27).

NOV and Eavor's TK™-18TC is a low thermal conductivity coating designed with better insulative properties while still retaining the same downhole performance (hydraulic performance/surface roughness, abrasion resistance, chemical resistance, impact resistance, and flexibility). The coating has a lower thermal conductivity, allowing the end user to better maintain the temperatures of the fluid within the pipe, and has an applied thickness of just 20-30 mils (thousandths of an inch). As with all internal coatings, TK™-18TC is also designed to extend the life of the tubular through corrosion and deposit mitigation.

Figure 26 Low heat coefficient coating for drill pipe.
(NOV, 2023)

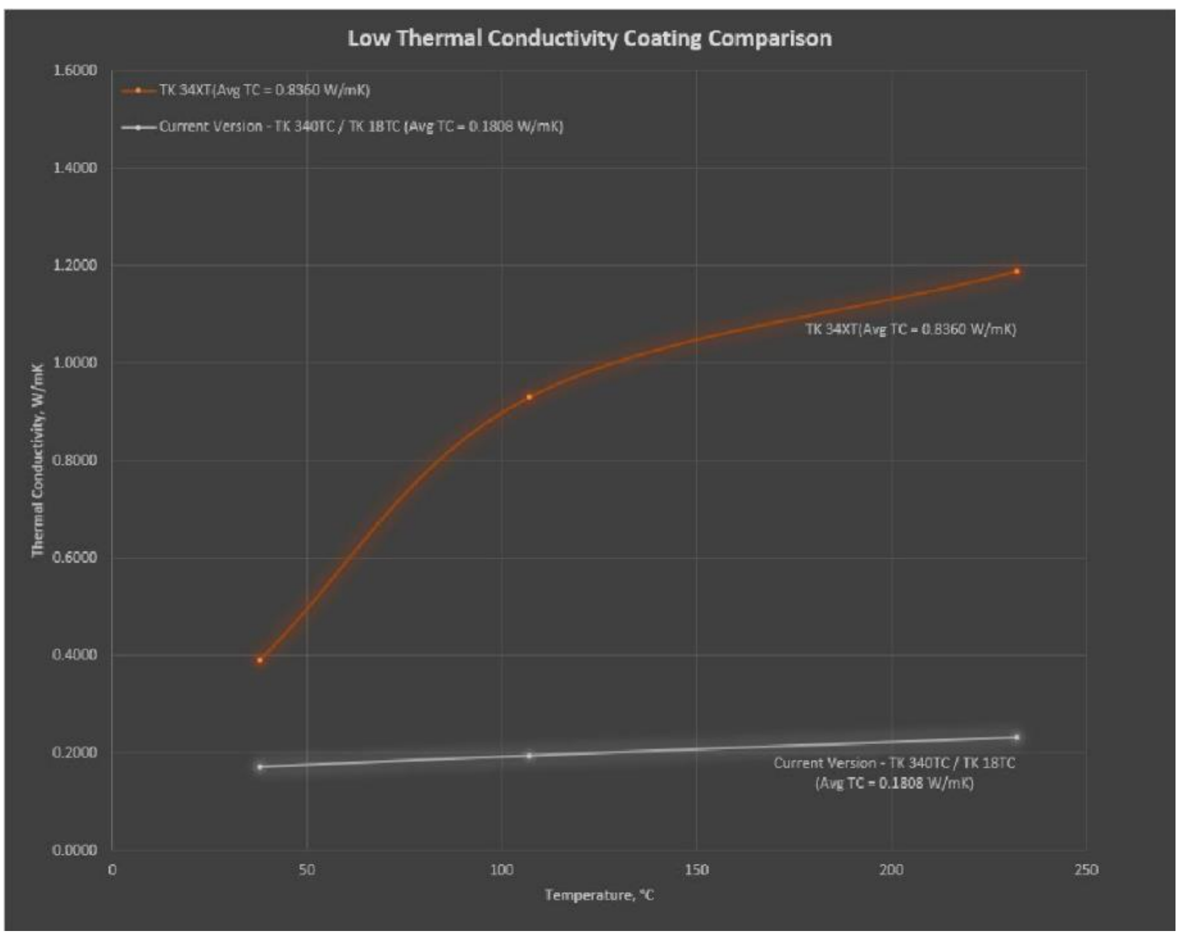

Figure 27 Thermal conductivity comparison between TK34XT and the low heat coefficient coating TK™-340TC/18TC.
(NOV, 2023)

Low heat coefficient coatings can be used independently to moderately reduce borehole temperature or used with insulated drill pipe and mud coolers to deliver much larger temperature reductions. Models have demonstrated that the temperature could be maintained below 150°C (Pink et al., 2023, SPE Stavanger).

Another company, Tuboscope, is also developing low heat coefficient coatings with even lower thermal conductivities, with the aim of helping future geothermal operators drill into deeper reservoirs with temperatures exceeding 300°C. Such innovations will also help operators in shallower, lower-temperature reservoirs minimize heat losses in the pipe to support applications such as district heating, low-enthalpy electricity generation, greenhouses, and hydroponics farms.

Gaps and challenges for SHR

Low heat coefficient coatings are used commercially in geothermal wells and other deep hot wells. When combined with mud coolers, insulated drill pipe, and other temperature management equipment, low heat coefficient coatings are at a TRL of 9 for SHR wells. Without these added components that improve insulation and cooling, they are at a TRL of 6. Continued research into low heat coefficient coatings and the potential use of nanoparticles and other insulative materials may further lower the conductivity. This research would be carried out most effectively through collaborations between national labs and commercial test partners. The low heat coefficient coatings may also be considered for insulative purposes on other tubulars in the wellbore.

6.2.5 Mud Coolers

Surface mud coolers are a relatively cheap solution to reducing borehole circulating temperatures. Mud coolers are effective in relatively shallow superhot geothermal wells, but if used with conventional drill pipe, the effectiveness diminishes with depth (Khaled et al., 2023).

Figure 28 shows that mud coolers effectively reduce the bottom hole circulation temperature (BHCT) of shallower wells (see Well A, 2,657 m). The BHCT in Well A decreases from 128 to 109˚C (a 15 percent temperature reduction) when the surface's mud temperature decreases from 70 to 30˚C. However, for deep geothermal wells (Well B), a mud cooler does not significantly reduce the BHCT while drilling if used without another insulative technology. The BHCT in Well B (2,617 m) is reduced only by 1 percent (from 179 to 177˚C) when the surface temperature of mud is decreased from 70 to 30˚C.

As the well gets deeper (with constant circulation rate), the total travelling time and distance of the drilling fluid to reach the bottom hole increases. When a mud cooler is used, the temperature difference between the formation and the drilling fluid is increased, which increases the heat flux per unit wellbore length from the formation to the drilling fluid. The temperature rise of the drilling fluid when travelling to the bottom is proportional to the total wellbore length (L), and the average temperature difference between the drilling fluid and the formation (ΔT).

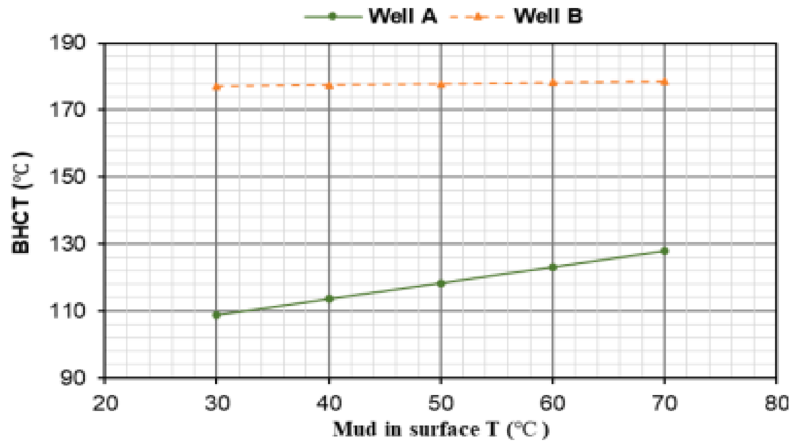

Figure 28 Impact of mud surface temperature by a mud cooler on BHCT of wells A & B.
Note the reduced effect of the mud coolers action for well B (Khaled et al., 2023).

Both NOV and Drill Cool manufacture mud coolers that could be utilized for cooling superhot geothermal systems while drilling. NOV manufactures a range of land mud coolers under the brand name Tundra™ Max, which operate with a flow rate of 350 to 500 gpm. If higher flow rates are required, units must be used in parallel or in series to lower the outlet flow temperature for a given flow rate. The Freshwater Geo-Cooler™ from Drill Cool incorporates a closed-circuit cooling tower with a DNV-certified offshore ISO container.

Gaps and challenges for SHR

Although results show that mud coolers are not an effective heat management strategy for SHR wells, they still offer benefits when used during drilling by maintaining low surface mud temperature. Lower surface mud temperatures increase crew safety and helps avoid mud pump failure caused by high-temperature mud. In addition, the effectiveness of mud coolers is increased when combined with IDP. Mud coolers that can be deployed for SHR projects exist today (and are therefore at TRL 9).

6.3 Conclusions

An SHR well must be cooled to operable temperatures during drilling operations, as high temperatures pose a risk to bit wear (Section 4) and downhole monitoring systems (Section 5). Deploying an optimal combination of existing and improved temperature management equipment—namely, mud coolers, IDP, low heat coefficient coatings, and drilling fluid—is likely needed to drill into SHR. Finding the optimal combination of these systems will require further high-temperature bench tests and in-field experimentation.

To overcome the mounting cost and weight incurred by excessive lengths of IDP, alternative technologies such as sCO_2 drilling and titanium drill pipe should be investigated. The major obstacle to sCO_2 drilling is the supply of CO_2, while the major obstacle to titanium drill pipe is cost. Scaling up SHR drilling may improve the availability and economics of these technologies.

7. Corrosion inhibition: Technology frontier and gap analysis

Corrosion inhibition is a major concern in geothermal projects, particularly for conventional hydrothermal systems where deep formation fluids are produced. For example, the brines from wells in the Salton Sea have a high Na-Ca-K-Cl type (approximate salinity 185,000 ppm Cl) with exceptionally high potassium, as well as the highest content of minor alkali elements known for natural water. Fe, Mn, Zn, Pb, Cu, Ag, and other metals are also present in exceptionally high concentrations. However, other waters produced from geothermal wells around the world are of near drinking-water quality and are noncorrosive.

Corrosion inhibition is largely beyond the scope of this paper as this concern is primarily for production companies rather than drilling operators. The drillers must, however, consider the impact of corrosion on drilling equipment, downhole tools, casing metallurgy, and the design of the cement. All the corrosive processes associated with drilling geothermal wells would be exaggerated under SHR conditions, which would accelerate the chemical processes.

Drill pipe can be protected with coatings. For example, corrosion-resistant coatings have been incorporated into the low heat coefficient coatings produced by NOV (Figure 29). Titanium drill pipe is very resistant to corrosion but is expensive compared to steel pipe.

The chemistry of the formation fluids and the presence of chlorides, carbon dioxide, and hydrogen sulphide also have an impact on the well design. Hydrogen sulphide is commonly present in O&G drilling and steel pipe, and casings are available in grades that are resistant to hydrogen sulphide embrittlement.

From a corrosion standpoint, the casing material must be selected based on the project life span, the temperature of the well, and the produced fluid chemistry. Depending on the conditions, the corrosion of the casing can be managed by selecting materials that withstand elevated temperatures, such as high-chromium, nickel-based alloys which can fortify casing integrity in geothermal environments. In lower-temperature but corrosive environments, non-metallic liners can be run inside the casing; these provide excellent corrosion inhibition at much lower cost compared to the advanced steel alloys. One example, NOV's fiberglass TK Liner, has a maximum temperature of only 121˚C; so, they can only be used in shallower well sections or in surface piping on an SHR project.

Figure 29 NOV's Glass Reinforced Epoxy corrosion-resistant casing liner.
(NOV, n.d.).

Gaps and challenges for SHR

Corrosion inhibition products are currently available at a TRL level 9, but in highly corrosive environments, those products could strain the economics of SHR projects.

Conclusions

Corrosion is a common concern for several industries, and innovation into high-temperature corrosion inhibition would benefit many industrial sectors, including geothermal. This innovation is best achieved through collaborative research projects between universities, national laboratories, and commercial companies who can test materials at full scale. Research into low-cost graphene coatings could be promising due to the conductive properties of graphene and its high resistance to corrosion at high temperatures.

8. Conclusion

SHR geothermal systems have the potential to provide long-term, scalable, renewable baseload power. Unlocking this potential requires significant innovation in drilling and well-construction technologies to improve ROP and develop high-temperature electronic downhole tools for MWD, logging-while-drilling LWD, and directional drilling in SHR conditions

Currently, rock-destroying equipment, high-temperature downhole tools, temperature management equipment, and corrosion inhibition share three overarching challenges:

1. Lack of access to SHR in controlled, laboratory settings,
2. Lack of access to SHR in in-field settings, and
3. Lack of incentives for collaboration between major drilling firms.

Collaboration between the public and private research community can help create these R&D conditions by first identifying all facilities around the world capable of SHR experimentation (e.g., Utah FORGE, IDDP), then creating the necessary incentives for greater cooperation between major drilling companies and research groups, and finally ramping up experimentation and R&D in SHR conditions.

Across all well-construction technology domains, one theme is clear: the technology to complete superhot or ultradeep geothermal boreholes and wells exists—but we must reduce the overall cost and time on task to drill a deep, superhot geothermal well. With continued support and development, the future of geothermal energy is extraordinarily bright. A list of technology-specific findings and a gap analysis table are all included in the Appendix.

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Appendix

Technology specific findings:

Conventional drilling

- Current status:
  - The highest ROP and longevity performance with PDC bits in SHR conditions
  - Advanced high-temperature, hard rock specific drill bits are commercially available.
  - The most mature drilling technique with high availability of drill rigs and operators relative to hybrid conventional methods
  - High level of directional control throughout borehole
- Technology gaps:
  - Design and optimization of cutters and bits to reach ultra-deep depths
  - Ability to reach SHR conditions of 375˚C
  - Weight on bit optimization for increased depths

Percussive drilling

- Current status:
  - Percussive systems have been deployed in supercritical conditions
  - 20 m/h ROP in hard rock formations at 6000 m
- Technology gaps:
  - Air hammer drilling inefficiency at depths due to loss of pressure
  - Need for real-work supercritical testing

Water jet drilling

- Current status:
  - Under testing and simulation for super- and ultra-deep wells
  - Reduces strain in rock formation therefore reducing tooling wear
- Technology gaps:
  - Surface systems to be designed to maintain flow rates and required pressures
  - Increased need for directional control systems
  - Improved understanding of standoff distance from borehole bottom
  - Still will require tripping and tooling repair for conventional bits

Plasma drilling

- Current status:
  - Combined system of plasma and conventional is under evaluation; testing in approximately 18 months
  - ROP in hard rock formations of up to 7.2 m/h in SHR conditions
  - Designed to be plug-and-play with current conventional drilling surface systems
- Technology gaps:
  - Efficiency of material removal is based on material properties, specifically boundary layers of the formation Circulation system for required dielectric fluid under evaluation
  - Maintaining power delivery to the drill bit

Millimeter wave drilling

- Current status:
  - Laboratory testing completed in hard rock simulations, maximum drilled distance of 8 m
  - Short borehole field testing to be completed fiscal year 2024 - 25
  - Theoretical benefits include avoidance of trip time
- Technology gaps:
  - Creation of drilling rig compatible to a 1 MW gyrotron
  - Ruggedization of the gyrotron
  - Impact of the property's hard rock formations and the effect on drilling, porosity, and dielectric conditions
  - Structural integrity of the waveguide at super- and ultra-deep depths
  - Lack of field testing to validate performance

Particle drilling

- Current status:
  - Laboratory and semi-scale testing completed with claimed market readiness in fiscal year 2024
  - Downhole hardware not affected by temperature and pressure for SHR drilling
  - Applicable for long runs in hard rock formations
- Technology gaps:
  - Inability to support direction control due to impacts with injected particles
  - Maintaining nozzle performance in downhole operations to continue circulation of injected particles

High-temperature downhole tools

- Current status:
  - High-temperature tools have been manufactured, tested, and run regularly at 175 ºC

    - A smaller range of tools manufactured by Baker Hughes, Hephae, and MB Century are rated to withstand >200 ^{o}C
- Technology gaps:
    - Rare materials are required to build electronics that can withstand SHR temperatures but they are expensive and slow to manufacture
    - An ideal system incorporating existing high-temperature tools (including one-run, encapsulated or standalone) with temperature management equipment must be modelled and tested in the field

Temperature management equipment

- Current status:
    - Components that support 400˚C currently available: insulated drill piping, coatings, and mud chillers
    - Industry developing new and novel techniques to support SHR applications
- Technology gaps:
    - Current carbon supply insufficient for geothermal at scale
    - Integration and packaging of systems still required
    - Possible introduction of exotic materials to improve efficiency

Corrosion inhibition

- Current status:
    - Corrosion inhibiting products are available but expensive and possible providing a negative impact to geothermal projects
    - Understanding of corrosion present in hydrocarbon industry, providing expert knowledge to improve systems for geothermal applications
- Technology gaps:
    - Managing location specific material to accommodate location-based ground composition

Technology gap summary table

Technology	Current state of technology	Future required state of technology	Technology readiness level (TRL)	Criticality for FOAK project	Steps needed to get to TRL 9
Conventional drill bits, PDC, roller cone, and diamond impregnated	Roller cone bits rated to 288°C performed successfully at high temperatures on the IDDP high temperature projects in Iceland but they should be phased out because of low ROPs. PDC drill bits have shown massive performance jumps on the FORGE project and most recently on the FERVO location. Current designs are delivering runs of more than 900 M at 30 m/hr in hard crystalline granite. Performance in igneous rocks with layers of high differential strength is still relatively unknown but performance in New Zealand with large PDC bits was very promising. The current state of PDC performance has already significantly changed the economics of SHR projects by reducing the number of days on location significantly. Drill bits are all steerable and the	We need to see ever improving performance, increased durability, faster rates of penetration, and higher temperature ratings. New bit designs and cutters are required for interbedded formations with large differences hardness between the different layers. Fast ROPs in basalts and very high compressive strength rocks. Increased stability to be able to handle vibration in the hard basement rocks. We will need to see a proven track record of PDC performance in igneous and metamorphic rocks above 400 °C. We need to see the impact of thermal spallation in combination with PDC bits, the lab results look promising.	PDC bits are at **TRL 8-9**, they just need to be tested and run at the SHR temp level. Roller cones are at **TRL 8-9** but have probably reached their performance limits.	**1**	Conventional PDC bits are already at a TRL 9 for SHR but because the performance of these products has such a large impact on project economics innovation must continue at pace. The biggest impact on performance comes from rapid iteration which comes from drilling lots of wells. We need to drill 10 x more geothermal wells in a lot of different rock lithologies then speed and durability will increase rapidly. All the drill bit manufacturers are working on material science of the bodies and advanced diamond technology for the cutters. Some collaboration between universities, labs and manufacturers would probably speed up future development. Studies are needed, on hybrid conventional bits coupled

	current temperature limitation of PDC bits is the “O” Rings holding in the nozzles which is close to 400°C.				with other secondary techniques like thermal spallation, particle impact, plasma, and water jet.
Percussive	Percussive drilling combines air or mud hammer drilling with rotary drilling techniques, that have demonstrated the capacity to drill to SHR conditions, or deep into hard rock. The leading firms behind percussive drilling include Strada Global, Orchyd, and HydroVolve. Percussive drilling was deployed for Stn-1, Fervo and IDDP-2. High ROP rates, 20 m/hr, have been demonstrated to >6000 m, suggesting that percussive drilling could be competitive with conventional rotary methods in ROP generation through hard rock. Further testing in SHR conditions is required.	Percussive drilling is a mature drilling method that requires repeated deployments in SHR conditions to verify its high ROP can be sustained in this domain. Their performance must match or surpass conventional rotary methods if it is to become the primary method of SHR drilling, but this can only be achieved with aggressive repetitions of in-field deployments.	Percussion drilling for SHR is at a **TRL 7** status. They have demonstrated high ROP and bit longevity in hard rock but require further testing in SHR domains.	**2**	Further experimentation at SHR test sites will validate the performance of percussion drilling for SHR projects. Like rotary methods, diversity in geological environments, drill bits and manufacturers will identify the optimal approach to reach SHR with percussive systems. This could be done coevally with rotary system experimentation at SHR sits, so both systems are directly comparable. Coordination between percussive drilling firms may improve innovation rates, but this requires strategic sharing of proprietary information.
Water jet	Water jet drilling is under two different application types: 1) Radial jetting, which has been successfully applied to stimulate current geothermal systems and 2) the use of	An increase in understanding of the performance, specifically in highly compressive formations, will be critical to deep borehole water-	Water jetting is **TRL 5** for deep geothermal drilling in hard rock.	**2**	Water-based systems are not yet TRL 9. This is due to multiple factors in regard to designs of the systems and understandings of interaction in hard rock for SHR

	high-pressure systems, along with a conventional drill it, to remove material downhole and reduce the stresses observed by the conventional drilling system. The Orchyd Project is the leader in water-based systems with their design to combine water-jetting and percussive in a singular system.	jetting applications as well as ensuring systems are able to maintain the high fluid flow rates required. For radial systems, it will be more in line with system optimizations as it has proven in the stimulation of under-performing geothermal systems.			applications. These items include, better directional control of fluid systems, increased modeling of flow dynamics on hard rock formations, and performance in high compressive strength formations.
Plasma	Plasma drilling is currently in the design phase. GA drilling, in conjunction with Nabors Industries, are developing both a plasma-conventional combined system, with downhole power generation as well as a stand-alone plasma system, most probably run on coiled tubing. The current timeline is to have the combined system completed and begin testing within 18 months.	Real-world testing needs to be completed to ensure technology application in SHR conditions. New surface level material and fluid handling systems need to be designed to work in conjunction with current hydrocarbon systems. Increased understanding of downhole power requirements and the effects of geological boundary layers will be critical to increasing effectiveness of the overall system.	Plasma based systems are currently at a **TRL 3-4** since deep borehole validation has not been completed.	**4**	To Reach TRL 9, systems will need to be tested in SHR conditions to validate performance. Currently, there is a lack of understanding of what the true performance of the systems will be. Design of electrical systems that do not pose any interference to required systems will also need to be validated.
MMW	MMW Drilling is in its design and laboratory experimentation phase,	Scale up in the lab and in-field is required to verify the potential to reach SHR	MMW drilling is at a current status of **TRL**	**4**	To reach TRL 9, repeated in-field experiments demonstrating scale up

	spearheaded by Quaise, Nabors, ARPA-E and ONRL. They have proof-of-concept that MMW drilling can vaporize rock to create a well, however the maximum depth penetration thus far is 2.4 m by 2 cm diameter. Plans to scale up experiments in the lab and in-field are in place, as is the acquisition of a high powered, 1 MW, gyrotron that may advance the penetration depth. Transmission of the mmw downhole is achieved with metal waveguide that must maintain a near-perfect vertical orientation or be at risk of vaporization. Methods to deploy the waveguide and cope with this constraint are under development. Bottom hole conditions are monitored through the waveguide, through reflectometry, spectroscopy, and radar, although this concept requires further testing.	domains with MMW. This initiates with acquiring a high powered gyrotron, with >1MW capacity. Equipment ruggedization and system design, as well as operability for drilling personnel follows this step. Further modelling of mmw absorptive properties for heterogeneous rocks is also required.	**2-3.** This may be advanced when in field tests are successfully completed.		potential for SHR drilling is required. Areas of inquiry include validation of the wave guide deployment, rig compatibility of the gyrotron, and the efficiency of rock vaporization. The design of a drilling stand capable of simulating SHR conditions is necessary for drilling experimentation.
Particle impact drilling	Particle impact drilling is provided by 2 companies, Particle Drilling (PD) and Canopus. PD injects 3%	The latest design modifications, post FORGE, should deliver ROPs over 30 M/hr and a run length	Particle Drilling are at **TRL 5 and**	**1 (Particle Drilling) 2**	Particle Drilling is commercial, but the company needs a buyer or a significant investor to be able

	particles (2 mm diameter) into the flow line and then accelerates those particles to impact and destroy the brittle crystalline rocks. The PD drill bit is a hybrid PDC reamer with particle accelerators. The Canopus system is somewhat similar, but it fires smaller (1 mm Diameter) particles out through the cutting face of the PDC bit. The Canopus system is also capable of steering the well and comes with and integrated MWD and RSS tool.	of 600M. For particle drilling to compete with conventional PDC bits the system needs to deliver run lengths over 1000 m. Particle Drilling has a lot of potential in very hard interbedded rocks with lots of layers of different hardness. Canopus needs to full scale test and manufacture a set of tools to run on a pilot project. They also need to be competitive with conventional PDC bits from ROP and durability.	**Canopus are TRL 4**.	**(Canopus)**	to continue operating. It then needs to be deployed to a SHR test rig and or a commercial project and iterate over multiple wells. Compatibility with MWD tools needs to be assessed and if required integration with a negative pulse tool or wired drill pipe. Canopus needs a full-scale test on a vertical drilling rig and can ruggedize and optimize the whole system. Their current MWD is an EM tool which has significant limitations in deep hard crystalline rock. They need to investigate an alternative telemetry method like negative pulse or wired pipe. Both Canopus and Particle Drilling would benefit from a significant government grant and or a large private investor. Both technologies show huge promise and are very close to being commercial.
High - temperature tools	A wide range of high temperature tools have been manufactured, tested, and run	It is possible to build 400 °C electronics out of exotic materials like Silicon	**TRL 8** when used with	**2**	To get to TRL 9 a complete system needs to be modeled, manufactured, tested, and

	regularly at 175 °C. There is a smaller range of tools at 200 °C. One manufacturer (Hephae) is working on 200-300 °C with the first iteration at 210 °C. Baker Hughes has run insulated tools with a cooling system above 300 °C on IDDP-2. MB Century have wireline tools for logging the hole up to 350 °C	Carbide and Gallium nitride but the practical application of this over the next 20 years is challenging. The preferred solution will be to build the most economically practical solution combining other temperature management methods and the highest rated electronic tools.	other cooling methods. **TRL 7** if encapsulated. **TRL 3** for 400 °C stand-alone tools.		run in the field to be field hardened. The system will then need to be iterated to reduce cost and improve performance.
Insulated drill pipe	There are three insulated drill pipe products and concepts. External coated (Drill Cool) has been manufactured and run on 2 projects. Internal coated (NOV) has been modelled and designed, test joints are being built. Vacuum sealed (Vallourec) has been built and run for production purposes but currently not suitable for drilling	The required state is that the insulated pipe lowers the fluid BHCT while drilling to below 175°C and return temperature to below 100°C. Modelling has showed that this can be achieved with a partial string of insulated pipe used in combination with other temperature management technologies.	The (Drill Cool) system has been run but not at SHR conditions, so **TRL 7** is most appropriate.	**2**	To get to TRL 8 a complete system needs to be modeled, manufactured, tested, and run in the field. A partnership between a SHR project owner and a pipe manufacturer needs to be formed. This process could be considerably accelerated with a government grant or private investment.
Drilling fluid	High temperature drilling fluids with reasonable rheology have been run up to 353 °C. Water can be used at SHR temperatures but in its simplest form it may only be fit for purpose to clean the hole at low inclinations.	Multiple fluid systems should be designed that are fit for purpose for SHR conditions. These fluids need to be able to cool the borehole, lubricate the hole, transport cuttings back to the surface and in	A SHR water-based system is at a **TRL 8** for low angle holes and a **TRL 7** for higher angle or horizontal	**2**	Labs and Universities combined with commercial partnerships should be working on water-based additives to create a water-based system that has all the rheological characteristics to be able to efficiently drill and

	Supercritical, liquid, and gaseous CO2 has potential as a working fluid, but it is in the concept, modelling design phase.	some cases minimize fluid losses or reduce the risk of fluid losses in the well. Separate systems will need to be designed where consideration is made for impermeable rock with low fluid loss risk and a permeable or fractured rock with high fluid loss risk. High temperature 400 ^{o}C test equipment is required.	wells. Using CO2 as a fluid system is at **TRL 3-4**.		clean a SHR well. Government grants, private equity investment could accelerate the development of CO2 as a working fluid and reduce the time to market by several years.
Low heat coefficient coatings	Low heat coefficient coatings, applied to conventional drill pipes, as part of a wellbore cooling strategy are commercially available today (NOV) and have been run into high temperature wells. They have not been run or tested at SHR temperatures.	Low heat coefficient coatings are a very practical, low-cost way of reducing the temperature of the fluid going into the wellbore. The lower the thermal conductivity of this coating the more effective it is at maintaining a lower temperature fluid. Work is required to produce a thin, effective coating with even higher capability than 0.16 W/mk.	The current coating is **TRL 9** but needs to be combined with other temperature management equipment to deliver the required fluid temperature at the tools and the bit.	**0**	Development of even higher capability coatings could be accelerated by partnerships between commercial entities, labs, and universities. There are probably materials out there that could make a significant jump in the performance of these coatings. R&D into materials science could yield a breakthrough technology as a coating or part of a coating.
Mud coolers	Mud coolers for SHR projects are commercially available today. There are multiple manufacturers and vendors. Their effectiveness is	A highly effective mud cooling system that can manage a high volume of high temperature fluid and reduce the temperature of	Mud coolers are commercially available today and are	**0**	Work can be done by the commercial entities to develop coolers that can handle a higher volume of fluid and deliver a large in

	somewhat dictated by the rest of the temperature management system and environmental conditions.	that working fluid significantly so it can be returned down the string at the appropriate temperatures. That temperature needs to be low enough so the other components in the temperature management system can keep the temperature at the bit below 175 ^oC	**TRL 9**. They can be used in parallel or in series to improve effectiveness. They do have a relatively high footprint on the location. They may require a large volume of fresh water to operate which may cause challenges.		and out temperature differential at increased flow rates. Research into complete temperature management and the sensitivities of various components should be done to try and find the most cost-effective solution.
Super critical CO_2	CO_2 as a working fluid for geothermal wells has been investigated since around 2000. This work has been mainly theoretical R&D. The physics looks very promising and there are oil and gas service companies who have the capability of building a complete system. One of the challenges could be sourcing plentiful volumes of CO_2 at low cost.	A full prototype CO_2 system needs to be built and tested on test location that has SHR conditions.	Using CO_2 as a working fluid for SHR conditions is **TRL 3-4**	**3**	A SHR test location needs to be developed somewhere in the US and potentially elsewhere in Europe, Africa, or Asia. The quickest way to do this would be potentially drill a deeper low angle well at the FORGE location or create a similar location in the western USA. A partnership needs to be formed between a commercial entity who can develop this technology and

					universities and national labs to support. Significant DOE or EU grants could accelerate development but access to a SHR test well is essential.
Fluid Dynamics, flow rates, turbulent vs. Laminar flow	It is well-understood that the creation of laminar flow in the annulus of the borehole can have a significant positive effect on insulating the fluid in the drill string.	A real-time SHR hydraulics model needs to be created where the borehole temperature can be modelled and adjusted in real-time to be able to create an environment where the temperature of the fluid is optimized.	**TRL 7**. Hydraulics models exist but they need to be adapted to SHR conditions and be turned into a real-time application.	**1**	This work could be done by a university, national lab and or a commercial entity. A small philanthropic grant or a DOE grant could accelerate the process.
Coatings, Material Science, Advanced alloys, Non Metallics, Graphene, Ceramics	Corrosion inhibiting products for SHR casing are available today, but they are very expensive. steel alloys using chromium and other metals are available that can survive in almost any environment. Corrosion needs to be taken into consideration by the drillers during the casing design process, but this topic will be covered in more detail in other papers. Corrosion of the drill pipe does need to be considered and drill pipes need to be specified to handle these environmental	Low-cost corrosion solutions using coatings is the ideal solution for the ID of the drill pipe. Drill pipe alloys can also be selected to minimize the risk of Hydrogen embrittlement when H2S is encountered. The future state would be finding commercially viable corrosion solutions for all steel tubulars that go into the SHR environment.	Casing and production tubing is available today that can manage corrosive, high-temperature environments, but it is expensive. **TRL 9**. Drill pipe alloys and strengths are available that can handle	**2**	Learning from other industries like the Petrochemical industry could have a significant benefit here. Otherwise, collaboration between labs, universities and industrial partners is needed to find some lower cost solutions to the corrosion problems in SHR drilling.

	conditions. The easiest way to manage corrosion is to drill SHR CLG and EGS wells where the drilling fluid chemistry can be managed on the surface.		corrosion in SHR conditions. Best solution is to drill hot dry rock and avoid hydrothermal formation fluids that are highly acidic.		
	A very limited supply of rigs that are available today that have all the specifications that are required to drill SHR wells. The longest hydrocarbon well to date is 15240 and was drilled off the Orlan Platform in Abu Dhabi. There are a few land rigs like the Doyon 26 and the Deutag T45 that have the pump capacity, the fluid storage capability, top drive torque, derrick strength, sub structure, BOPs and drawworks capability to drill these wells. The downhole temperature will need to be managed to ensure fluid return temperature is below boiling point and does not damage BOP rubber elements.	The main problem here is not the technical readiness but the limited supply. Most of the rigs that are suited for these projects are either old and require significant overhauls or are on long-term Oil and Gas projects. If new rigs are being built for SHR geothermal projects then additional consideration needs to be made for drilling in more densely populated areas, taking power from overhead lines, noise reduction, robotics, small loads, smaller crews.	**TRL 9** equipment is available today even if it is not quite optimal.	**1**	A test location or commercial SHR operation is needed that has a long-term schedule of wells (Greater than 5 years). A project like this would provide an incentive for a rig manufacturer to build a custom fit for purpose rig for SHR geothermal. DOE funding of such a project would accelerate the development of these rigs and the supply chain that needs to be created for such a facility.

	The rigs may need to come with additional equipment like MPD, mud coolers, particle drilling, automation, robotics, and continuous circulation. Additional pad space may be required to handle large volumes of fluid to allow evaporative cooling.				