Superhot Rock Energy

A Vision for Firm, Global Zero-Carbon Energy

Updated November 2022

CLEAN AIR TASK FORCE

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Executive Summary

Superhot rock energy is poised for a breakthrough as a high-energy-density, zero-carbon, always-available energy source that could be commercialized worldwide in the 2030s. Analyses for Clean Air Task Force (CATF) by Lucid Catalyst and Hotrock Energy Research Organization (HERO) suggest that, with more ambitious geothermal energy funding and public-private partnerships to spur innovation, it could be cost-competitive with most zero-carbon technologies—transforming global energy systems by providing clean, firm, cost-competitive renewable energy while requiring significantly less land than other sources.

Today's conventional geothermal systems have a global capacity of only 16 gigawatts (GW) of power, and are geographically limited to regions where concentrated heat is located near-surface (e.g., volcanic areas or areas where the crust is thin, such as the U.S. Great Basin or East Africa).[1] Compared with today's 2,100 terawatts (TW) of coal capacity in 69 countries, or even today's 1TW of photovoltaic capacity, geothermal energy occupies only a small niche. Superhot rock energy could compete with these energy resources by tapping deep superhot conditions (400°C or hotter) that exist everywhere, deep in the Earth under our feet.

In superhot rock systems, water is injected to depths where the rock temperature exceeds 400°C and then is returned to the surface as supercritical or superheated water to power generators. Several research and development (R&D) projects around the world have already drilled into superhot rock and have begun developing methods for operating in these extreme heat and pressure conditions. While superhot resources have yet to be harnessed for power production, their high energy potential is wildly recognized. Evidence from a test well drilled by the Iceland Deep Drilling Project (IDDP) suggests that an estimated 36 megawatts (MW) of energy could be produced from one well—approximately five to ten times that of a typical 3-5 MW commercial geothermal well today. If this substantial amount of energy can be produced in dry rock at reasonable development costs, based on a preliminary analysis for CATF, superhot rock could be competitive with today's natural gas plants at $20-35 per megawatt-hour (MWh).

Significant engineering innovations will be required to realize the full potential of superhot rock, such as rapid ultra-deep drilling methods, heat-resistant well materials and tools, and deep heat reservoir development in hot dry rock. But these are engineering challenges, not needed scientific breakthroughs. Intensive drilling campaigns can drive rapid learning to address these engineering obstacles and drive further cost reductions. This can be accomplished by geothermal companies or consortia, including highly capitalized oil and gas companies, incorporating innovations from unconventional oil and gas experience. Big tech can also speed the deployment of superhot rock energy by investing in early-stage technology development and providing power purchase commitments. With significant private and public investment, along with protective regulatory policies accompanied by rapid review and continued technological innovation, superhot rock energy can plausibly be commercialized in the 2030s.

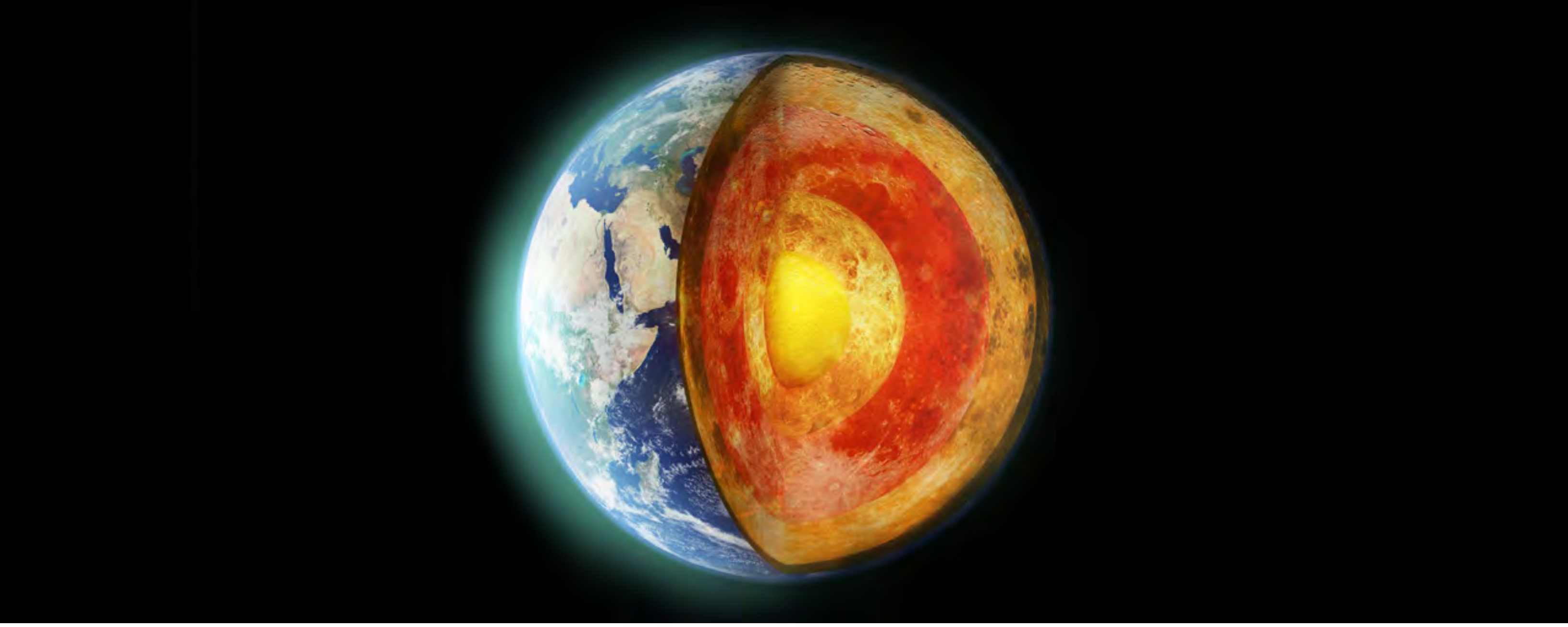
A key first step to commercial superhot rock energy will be moving power demonstrations forward in the 2020s. Several companies are currently preparing for or anticipate projects in this timeframe. These proof-of-concept power production demonstrations will demonstrate the value of superhot rock energy to the energy community and spur investment in large, commercial-scale drilling campaigns. Then, as next-generation superdeep drilling methods are commercialized, superhot rock energy can progress from shallow hot regions to continental interiors where heat is deeper.

The Value of Superhot Rock Energy

- **Cost-competitive** terawatt-scale power and heat
- **Inexhaustible** resource, Earth's heat is everywhere beneath our feet
- **Available 24/7** firm baseload power
- **Energy dense** with minimal surface footprint

- **Zero greenhouse gasses** at point of production
- **Pivots fossil workforce** and technology
- **Potential to repower** fossil power plants
- **Generate zero-carbon fuels** like hydrogen and ammonia

- **Accessible worldwide** with deep drilling innovation
- Significant engineering advancements required but **does not depend on scientific breakthroughs**
- **No fuel cost** associated with geothermal heat
- Ensuring **energy security** by producing firm, zero-carbon power domestically



SECTION 1

Superhot Rock Energy Potential

1.1 Tapping into the Earth's Deep, Endless Heat

The Earth's deep heat is an energy resource everywhere beneath our feet, that can be accessed to provide heat and power at a scale adequate to meet the growth associated with economic development while aligning with the transitioning energy sector—including as a carbon-free energy source for industrial and district heat and transportation. The Earth's deep heat is inexhaustible for energy extraction purposes, and superhot rock technologies are under development to tap into it.[2]

Today's conventional geothermal industry is limited to locations where both heat and groundwater exist near the surface. The rarity of these "hydrothermal" systems—such as Old Faithful[3]—is the primary reason that global installed geothermal electricity capacity only reached 16 GW in 2021—less than 0.2% of total installed global power.[4]

To expand geothermal energy's global reach, engineered systems in hot dry rock seek to emulate conventional hydrothermal energy production by injecting water into hot dry rock and producing steam.[5,6] These hot dry rock systems are typically described as "enhanced" or "engineered" geothermal systems, or "EGS." A 2019 U.S. Department of Energy (DOE) analysis estimated that the U.S. geothermal electricity resource[7] in the United States is more than 5,000 GW of electricity, about five times total U.S. installed utility-scale generation capacity in 2016.[8] And a 2006 Massachusetts Institute of Technology (MIT) report estimated that U.S. engineered geothermal systems could potentially produce over 2,000 times annual U.S. primary energy consumption in 2005.[9] Furthermore, the MIT analyses were limited to a depth of 10 kilometers (6 miles), effectively excluding the huge potential of deep superhot resources. These studies mean that the deep geothermal energy potential is enormous, and far more if superhot rock potential is considered.

Figure 1

Commercial geothermal systems are currently limited to the red or dark orange zones in continental areas on the map below. Superhot rock could extend geothermal to much of the rest of the world. (Davies 2013)[10]

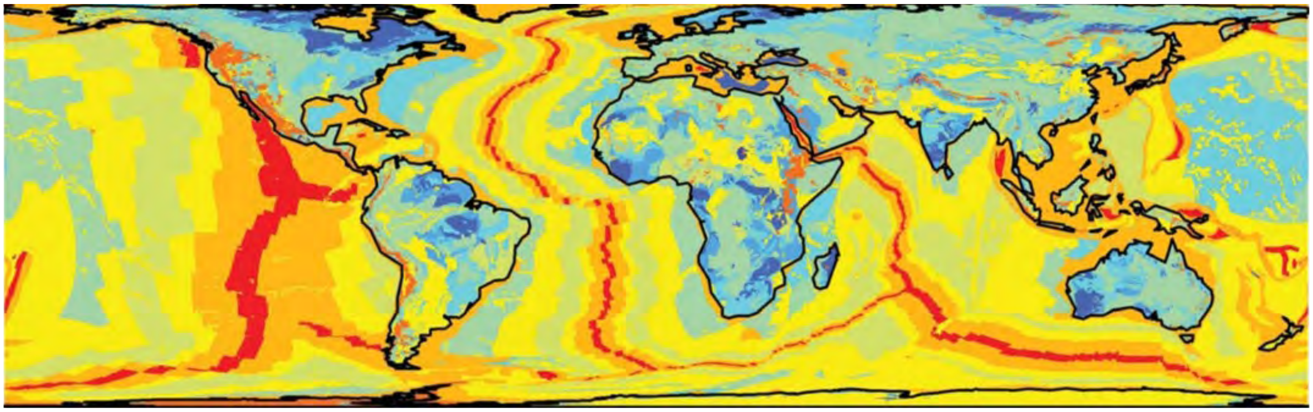
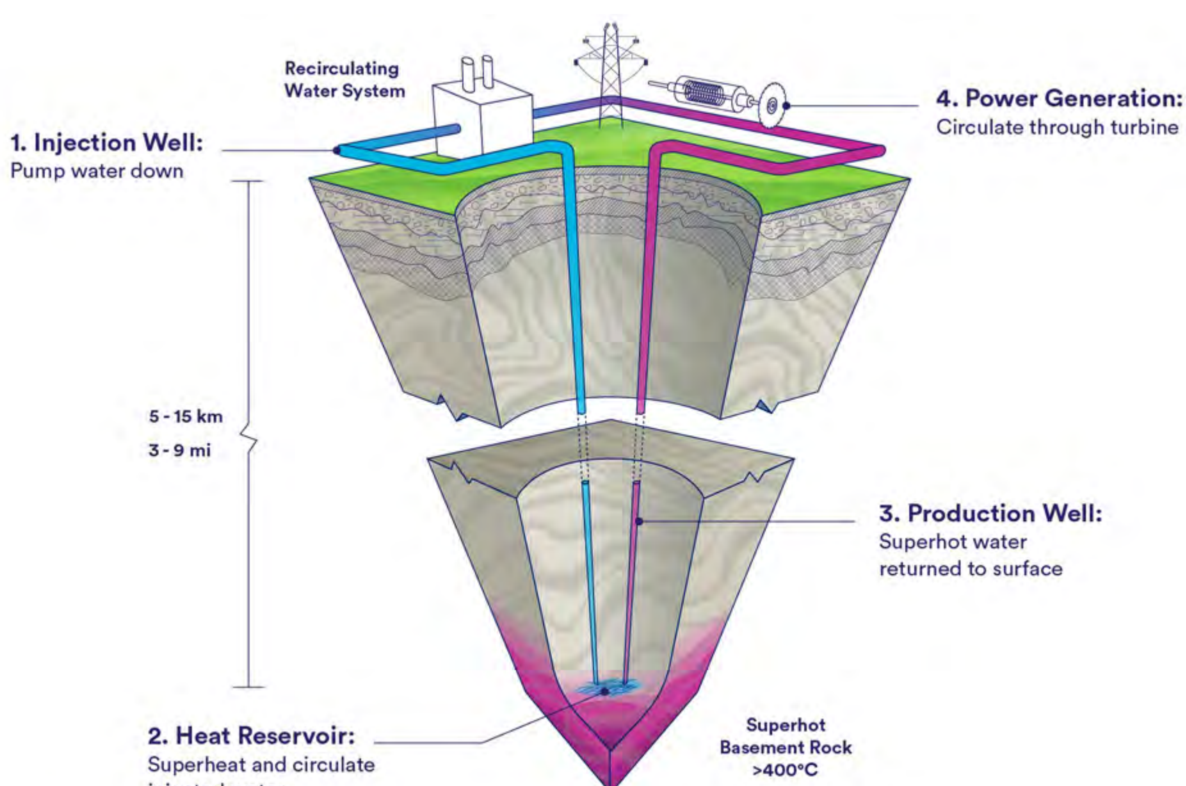


Figure 2

Superhot geothermal energy is mined from natural heat deep within the Earth's crust. Water is injected (through an injection well) into superhot dry rock (rock at temperatures above 400°C) and is circulated through fractures (or drilled conduits) to a production well that provides thermal energy to produce power, heat, or fuels. Accessing affordable superhot resources could transform the power industry but will require innovations in drilling and reservoir engineering.



Note: Not to scale. Underground flow conduits for water may either involve below-ground piping or fracture networks (pictured).

Figure 3

Conventional commercial hydrothermal systems collect steam or hot water from shallow, heated groundwater. Engineered geothermal systems (commonly deemed "EGS") are designed to collect deep heat by circulating water through hot dry rock. Superhot rock systems are deeper, hotter dry rock systems that circulate water through rocks that are above 400°C, bringing far more energy (five to ten times) to the surface per well.

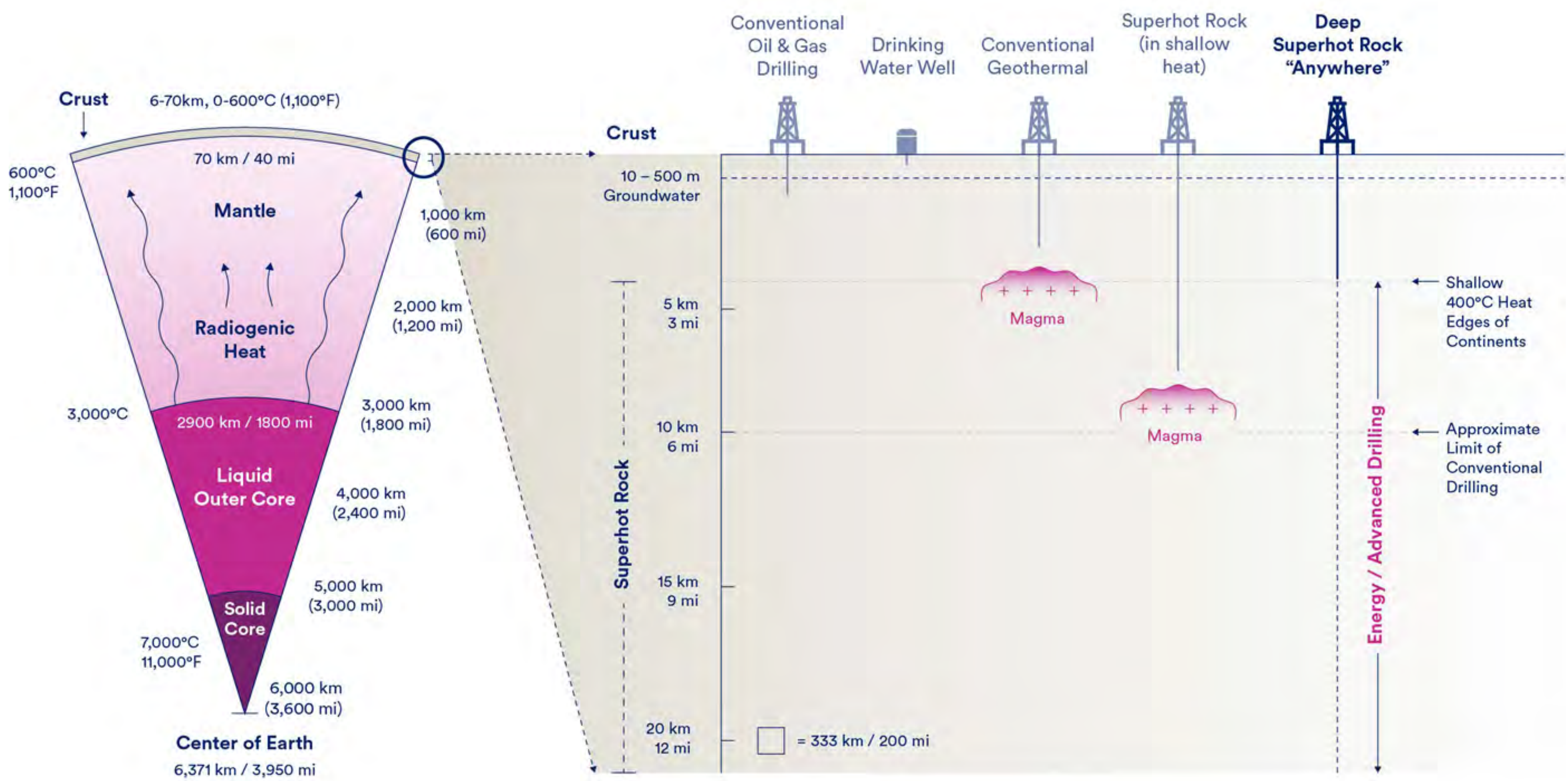


Figure 4

Superhot rock energy will heat water by circulating it through cracks or drilled conduits in rock exceeding 400°C. For example, researchers at FORGE Utah have been testing methods for injecting water through ancient tectonic fractures, like those in the photos, that occur in these 400-million-year-old granites in New Hampshire, USA (left) and half-billion-year-old granites from Maine, USA (right).

Figures 2 and 3 illustrate how superhot rock energy takes advantage of deeper, hotter, and more energy-dense rock. These systems will inject water down a deep injection well and circulate it through hard crystalline "basement" rock, where temperatures are 400°C or higher, via fracture systems (similar to those in Figure 4). Other options being explored include micro-tunnels drilled single or multi-well reservoir systems. The heated water will then be circulated back up production wells to generate electricity at surface power facilities. With the ability to drill, engineer wells, and create deep thermal reservoirs, geothermal energy could be tapped nearly anywhere in the world.

1.2 High Energy Density

Superhot rock energy promises to be vast, but also very energy-dense, generating large amounts of energy beneath a small surface footprint—a key superhot rock advantage (Figure 5). This advantage comes from the potential to harvest concentrated heat from kilometers of subsurface heat resources, combined with modern drilling methods that minimize the land use of drilling pads. Figure 5 illustrates hypothetical comparative land usage for the energy consumption of Italy, showing how the high energy density of superhot rock systems require far less land use than other energy resources.

Why does superhot water carry so much more energy? The injected water transforms into a superhot, superfluid form scientists call "supercritical" water.[11] Supercritical water can penetrate fractures faster and more easily and can speed far more energy per well to the surface—roughly five to ten times the energy produced by today's commercial geothermal wells or predicted for lower-temperature engineered wells.[12] This means that a few superhot rock wells can bring substantial commercial energy to the surface. This high energy potential has been demonstrated in Iceland, where the Iceland Deep Drilling Project's "Krafla" borehole produced natural superhot water at 452°C and an estimated 36 megawatts of energy (MWe) production potential.[13] In comparison, a typical commercial hydrothermal geothermal project produces about 3-5 MW per well.[14] For comparison, the Reykjanes geothermal field in Iceland, one of the hottest producing field in the world at 290-320°C, has 12 wells producing a total of 100 MWe from 2 turbines.[15] Superhot rock energy has the potential to produce the same amount of heat in 2-3 wells. This is why superhot rock is sometimes referred to as the "Holy Grail" of geothermal energy—because more heat energy could be harvested from far fewer wells. Furthermore, this means that the surface area required to feed a very large power plant (hundreds of megawatts or a gigawatt in size) could be relatively small and associated well construction and maintenance costs would be reduced.

1.3 Competitive Dispatchable Power

Clean Air Task Force commissioned Hot Rock Energy Research Organization (HERO) and LucidCatalyst (LC) to estimate the levelized cost of commercial-scale superhot rock electricity. HERO and LC developed a power plant cost model based on anticipated Nth-of-a-kind costs for a superhot rock plant, using known wellfield costs and power generation costs (sourced from cost data from existing geothermal and thermal plants). The model estimated the levelized cost of energy for different technology regimes, from existing technology to future technologies such as the yet-to-be-commercialized high-energy drills. Results suggest mature superhot rock will be competitive at

Figure 5

This illustrative and hypothetical diagram is scaled for the total energy use of Italy and shows that the amount of energy delivered by geothermal systems per unit of surface (land or ocean) area is very high; conversely, the amount of surface utilized is very small per unit of energy delivered. This simple graphic illustrates the relative magnitudes of surface area used for several forms of energy and highlights the potential land use advantage of superhot rock energy. Relative sizes of squares were scaled-up for the total final energy use of Italy for illustration purposes only. The ratios are based on Italy's 2019 IEA Energy Balance and are not based on an independent energy analysis for Italy.[16]

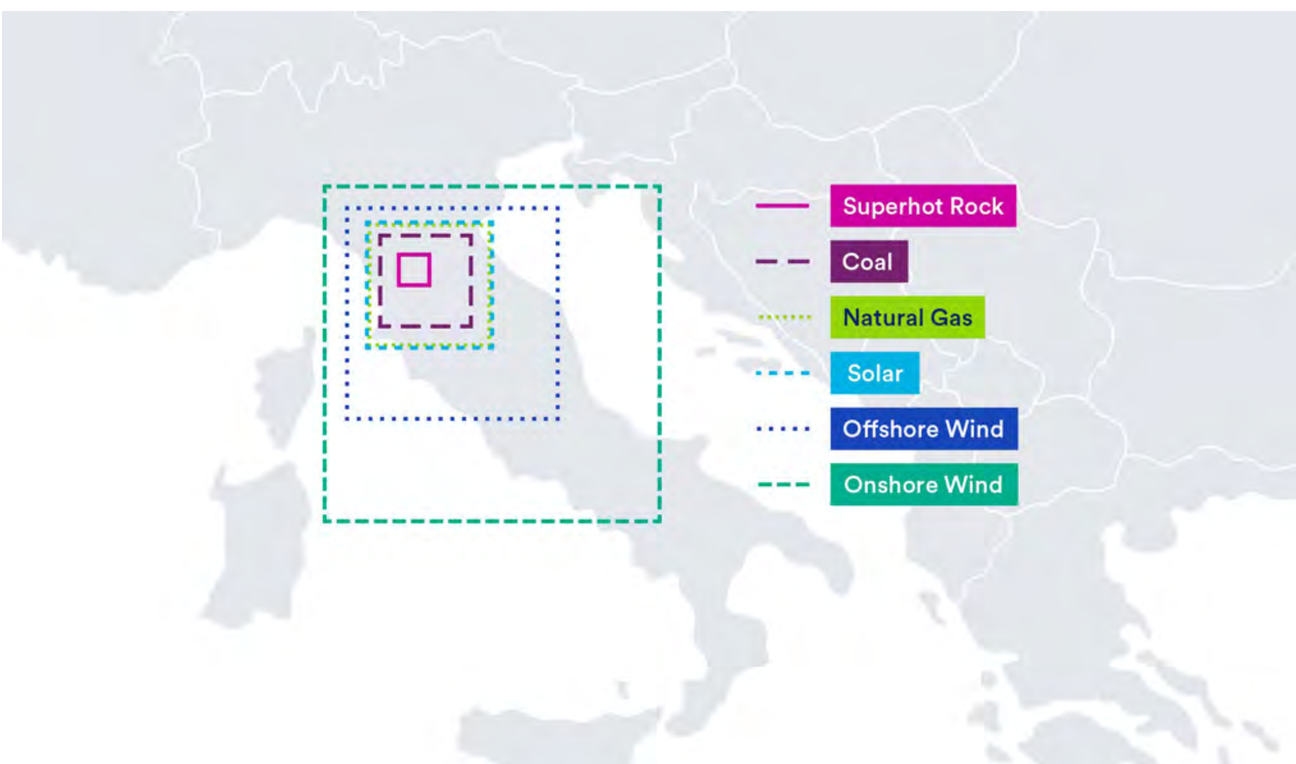
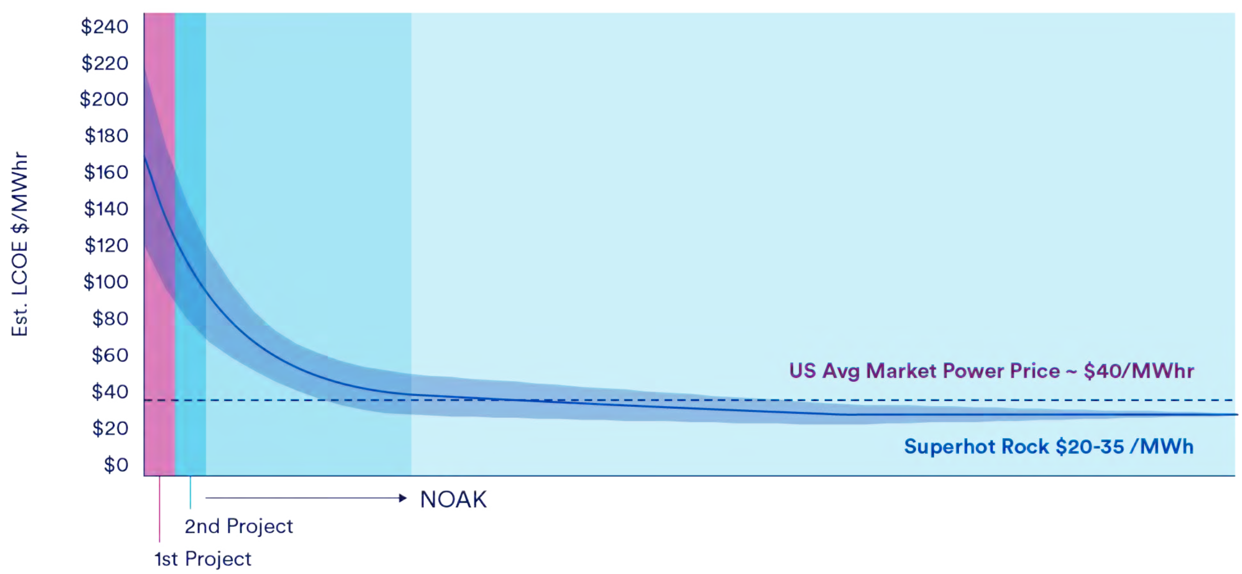


Figure 6

Illustrative graph shows how electricity produced from superhot rock is expected to be competitive for Nth-of-a-kind plants (NOAK) based on estimated levelized cost of electricity after full commercialization. Lucid Catalyst and Hot Rock Energy Research Organization (HERO) have preliminarily estimated that superhot rock geothermal could have an LCOE in the range of $20-$35 / MWh. This would be competitive with other dispatchable and intermittent energy resources.



$20-35 per MWh (Figure 6).[17] Drilling and reservoir development costs—combining labor, equipment, and materials costs—are expected to be higher for first-of-a-kind projects but to progressively decline through continuous improvement, similar to the deep cost reductions and productivity improvements that occurred in large-scale unconventional shale oil and gas development.

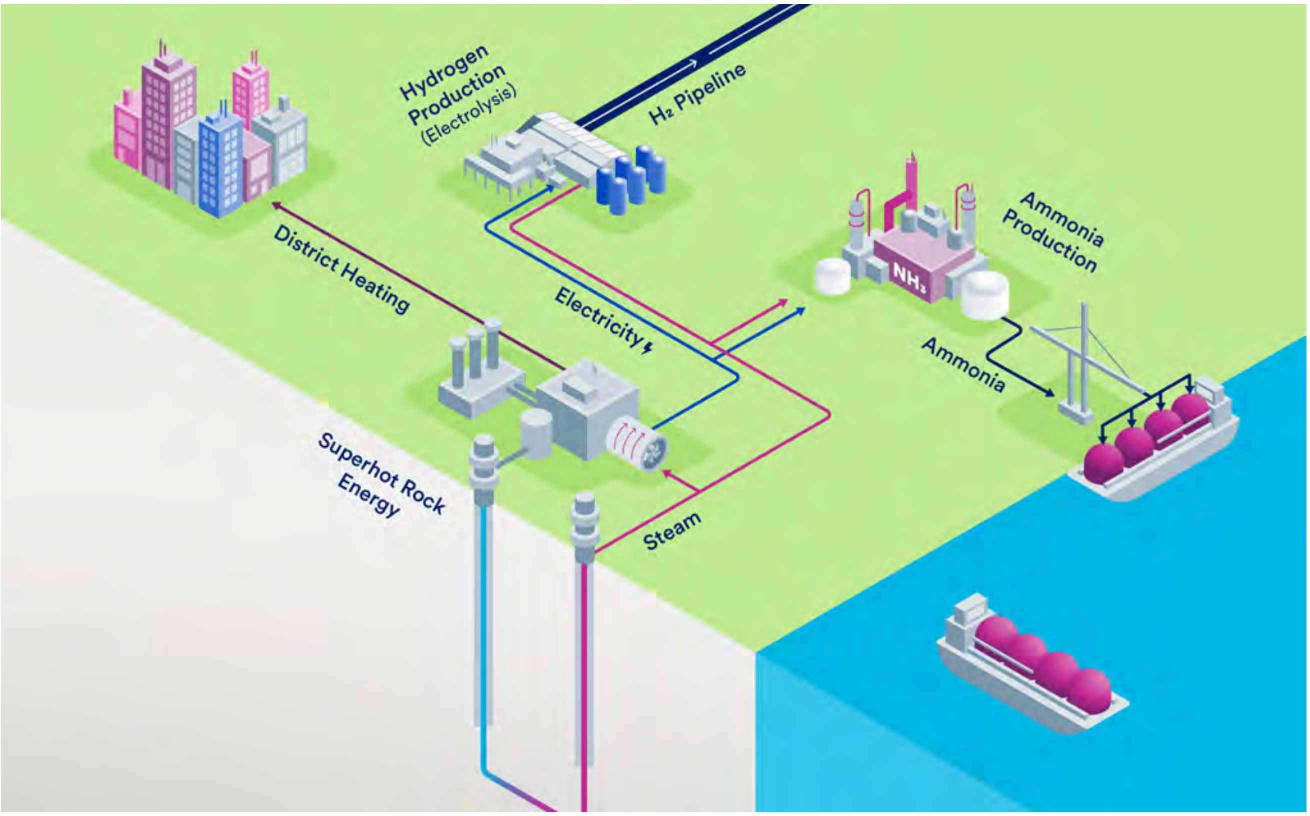
1.4 Superhot Rock Hydrogen Production Potential

Because superhot rock plants promise low-cost electricity and high-quality heat, they could be excellent resources to produce zero-carbon fuels such as hydrogen and ammonia. The techno-economic cost model developed by HERO and LC for CATF estimated production costs for these two fuels, both assuming the use of high temperature steam electrolysis via solid oxide electrolyzer cells (SOEC).[18]

Reliably achieving hydrogen production costs at or below $1.50 would achieve parity with the costs from producing hydrogen in an environment with low natural gas costs. With advanced drilling and casing technologies, the costs begin to approach $1/kg, which would achieve the DOE's 2030 Hydrogen Earthshot Initiative target cost. This would have significant implications for ammonia production, as well as for the production of other synthetic fuels that could play a major role in decarbonizing the global liquid fuels industry.

Figure 7

Superhot rock energy could generate hydrogen using high temperature steam electrolysis from its zero-carbon electricity and heat from the superhot steam, extending its use to transportation.



1.5 Manageable Environmental Footprint

Like all energy sources, superhot rock energy may have environmental impacts requiring mitigation, but these should be modest and much less than comparable resources when considering the magnitude of energy produced.

No direct greenhouse gas emissions

Unlike fossil power, no direct carbon dioxide (CO_2) will be produced in the process of generating power in dry rock. This also represents a small advantage over commercial hydrothermal geothermal systems, some of which can emit low levels of carbon dioxide from the natural water used to produce power.

Minimizing drinking water risk

While superhot rock energy will involve injecting water into existing and new stimulated fractures underground, water utilization is expected to be minimal as the produced steam will be condensed and reused in a largely closed circuit. This will require makeup water for water loss but will not require continual refreshing. Furthermore, non-potable brines may be possible working fluids. Moreover, superhot wells will inject recycled water far deeper (typically 4 kilometers or deeper) than near-surface drinking water aquifers (typically a few hundred meters in depth), leaving several kilometers of impermeable crystalline rock to effectively seal off the superhot rock “reservoir” from near-surface water resources. All U.S. geothermal projects must currently operate under the Safe Drinking Water Act's Underground Injection Control rules (typically termed "UIC") or state program equivalent, to ensure potable water is protected from contamination. Regulatory review of current UIC and related state and international regulations will ensure robust and predictable water protections appropriate for the risk profiles of superhot rock systems.

Small surface footprint

Superhot rock energy does not require thermal generation facilities such as boilers for fossil and nuclear energy. Neither does superhot rock energy have the immense land utilization that solar panels do. Instead, superhot rock surface equipment will be limited to a buried heat gathering system connecting wells to the electricity production facilities comprised of steam turbines, electricity generators, and transmission facilities. Innovations from unconventional oil and gas may further minimize the surface footprint of superhot rock wells through drilling of multiple injection and production wells from a single movable drilling pad, harvesting significant amounts of energy from a single project site.

Minimizing induced seismicity risk

Seismic activity and "felt" earthquakes (and, in a few cases, earthquakes that caused damage) have been recorded in lower temperature engineered projects where water has been injected into hot, dry (but not superhot) rock (e.g., Vendenheim France; Pohang, South Korea; Basel, Switzerland).

There are several strategies that may help ameliorate seismic risk from projects in hot dry rock. First, recent experience suggests advanced site study and selection is primary step that should be required in advance of approval to proceed. For example, pre-project study of natural seismic activity could have identified the active fault zone and might avoided triggering the South Korean Pohang quake. Useful methods could include seismic profiling and baseline seismic and microseismic monitoring to identify and avoid such active fault zones. Second, microseismic monitoring-informed "green light/red light" systems have been pioneered, and found effective, that require temporary shutdowns or slower injection rates if significant earthquake activity risk is elevated during operations.

The U.S. Frontier Observatory for Research in Geothermal Energy (FORGE) has a focused research effort on earthquake avoidance in lower temperature engineered systems,[19] which should help inform regulatory development. Furthermore, in Japan, scientists are studying the possibility that rock at 400°C (700°F)—in the so-called "brittle-ductile transition zone," or "BDT"—may have plastic-like properties which may be less likely to generate seismic activity from injection operations. Further laboratory in field testing is required to test the BDT hypothesis.

SECTION 2

Status of Superhot Rock & Necessary Innovations

2.1 Superhot Rock Initiatives, Past & Present

Engineering concepts for hot rock geothermal energy systems originated in 1970 at Los Alamos National Laboratory.[20] This project continued through 1992, systematically exploring the hot dry rock concept through drilling and related experiments. Other early projects included Rosemanowes in the UK, followed by the operational Soultz-Sous-Forets and Rittershoffen EGS plants in Alsace, France. Later, the EU's Horizon 2020 initiative funded DEEPEN, a superhot research and development initiative including drilling projects in Italy and Iceland and research in Mexico and New Zealand. The EU Geothermica initiative continues these efforts.

Over two dozen wells have been drilled into superhot rock conditions around the world. The map (Figure 8) shows global superhot rock initiatives (blue dots) and numbers of wells that have encountered superhot rock. These wells have generally been in comparatively shallow, high-temperature heat below existing geothermal fields, typically at depths of around 3-7 km (2-5 mi).

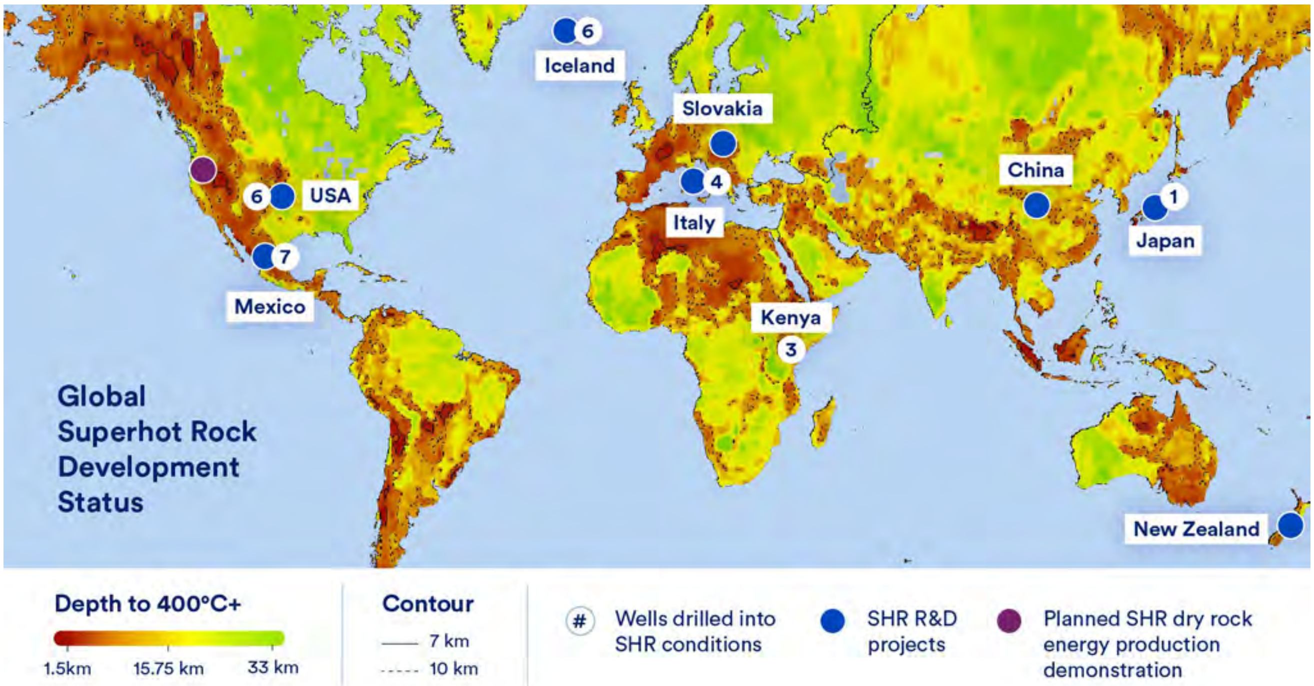
The following initiatives have focused on drilling and superhot rock energy technology development. Although power has yet to be produced from any superhot rock well, these projects and others have provided important learnings and continue to inform the innovations needed to move commercial superhot rock energy forward.

Japan Beyond Brittle Project

Japan's New Energy and Industrial Technology Research and Development Agency (NEDO)'s Kakkonda well in northeast Japan was drilled in 1994-1995 to temperatures above 500°C at a depth of 3.7 km (about 2.3 mi). Further investigation suggested that the well drilled into a zone of low earthquakes known as "brittle-ductile transition zone," where rock is more plastic and possibly less susceptible to brittle failure. JBBP's superhot rock research continues at Tohoku University, focusing on reservoir development in superhot conditions and identifying strategies for minimizing the risk of induced seismicity.[21] JBBP contemplates eventually drilling a second exploration well as a part of the project.

Figure 8

Global superhot drilling and research sites. Dark red indicates areas where superhot rock heat is available less than 10 km below surface, the most viable regions for early superhot rock energy development. (Heat map: Pacific Northwest National Laboratory and HERO).



Iceland Deep Drilling Project

IDDP has been a superhot drilling initiative for over a dozen years as a part of the EU's DEEPEGS program.[22] The first test well, IDDP-1 Krafla, was completed in 2009, after drilling was terminated when it encountered magma. Krafla provided an important demonstration of the energy potential of superhot wells with a projected energy flow of 36 MWe. The second IDDP well, IDDP-2 Reykjanes, reached its objective of supercritical (superhot) conditions at 426°C in 2017. IDDP plans to flow test the well in the future, pending funding. IDDP is anticipating a third superhot well, IDDP-3, in Hengill, Iceland, near the Nesjavellir plant; however, it is currently unfunded.[23]

DESCRAMBLE

Italy's Larderello geothermal field has been a heat resource for two centuries, with electric power production since 1913, and was the site of an intensive EU collaborative effort from 2015-18 (known by the acronym DESCRAMBLE) to drill into superhot rock as a part of the EU DEEPEGS program. Superhot conditions were originally encountered in the early 1980s in Larderello's San Pompeo-2 well.[24,25] Larderello's Venelle-2 is the hottest geothermal well on record, registering 514°C at a depth of 2.9 km (1.8 mi).

GEMex

GEMex is an EU-supported program focused on hot dry rock/EGS development and SHR systems. It drilled several wells at the Acoculco geothermal field, reaching "well above" 300°C in dry wells. GEMex also investigated and modeled the superhot system at the Los Humeros geothermal field in anticipation of drilling the supercritical system in the future.[26]

Hotter and Deeper

The HADES project in New Zealand has been exploring superhot resources in the Taupo Volcanic Zone since 2009 and is planning a scientific drilling project into New Zealand's deep-seated superhot rock.[27] Like JBBP, the project hopes to investigate potential existing reservoir systems in the superhot plastic brittle-ductile transition zone at about 7 km, where geophysics suggests there is little seismic activity. This is another EU-supported project.[28]

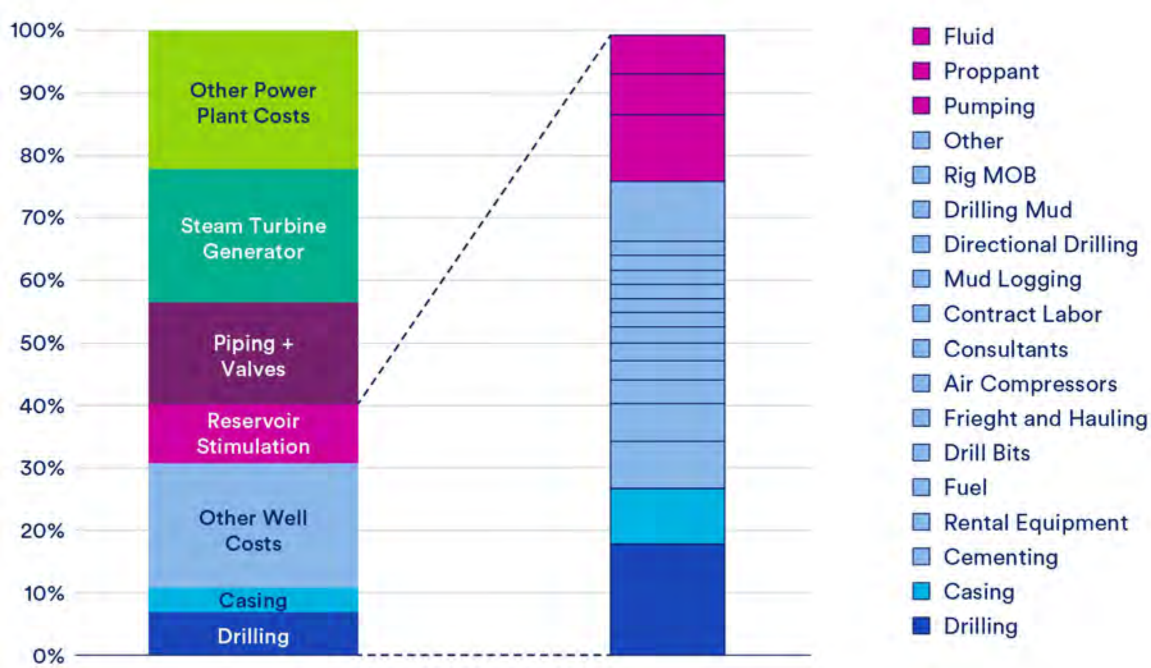
2.2 Innovations Needed for Commercialization of Superhot Rock Energy

Research and development wells used conventional drilling to reach superhot conditions for several decades. Yet new tools and technologies are needed to drill and complete wells to produce energy at these superhot temperatures and at deeper depths than ever.[29] The long-term need to enable successful "geothermal everywhere" is drilling innovation to reach far deeper resources at reasonable cost. But innovations are also needed in such areas as subsurface reservoir creation, well metallurgy and cements, downhole power supply and monitoring, and surface power conversion. All these technologies have been anticipated and are at various stages of development for very hot commercial applications, with some adapted for use in pilot superhot drilling operations like in Iceland.

Extrapolated from costs of today's commercial geothermal plants, operations and maintenance in superhot rock systems should have little effect on the levelized cost of electricity (LCOE). As in most renewable energy power plants, the LCOE will be primarily driven by capital expenses (as illustrated below in Figure 9). This means that, once in operation, there will be no resource cost volatility—unlike power from baseload fossil plants, which can swing with the cost of coal, oil, and gas. This figure also illuminates the need for cost reduction innovations throughout the entire cost structure, as no single category or technology consumes more that 30% of the total

Figure 9: Estimated Breakdown in Capital Cost for a Hypothetical 250 MW SHR Plant

Based on costs from today's commercial geothermal plants, operations and maintenance in superhot rock systems will have little leverage on the levelized cost of electricity, which will be driven more by capital expenses. This means that, once in operation, there will be no resource cost volatility—unlike power from baseload fossil plants, which can swing with the cost of coal, oil, and gas. Note that drilling represents a small part of capital cost (Lucid Catalyst for CATF, 2022).



capital cost assumptions. While there are currently significant efforts underway to reduce the cost of drilling, this alone will not push superhot rock energy to a point that it is at grid parity with other producers today. (LucidCatalyst and HERO for CATF, 2022).

Drilling Superhot Rock

The deepest well ever drilled in crystalline hard rock—12.5 km, 40,000 feet, or almost 8 miles deep—was completed in the 1970s in the Kola Peninsula of Russia. However, this was in rock at much lower temperatures. Currently-available large mechanical drilling rigs are being used today to drill to depths of 3-7 km (~2-4 mi) in relatively shallow superhot rock. The challenge of drilling and widely deploying superhot rock will require innovative new technologies that can cost-effectively reach superhot resources in hard crystalline rock at depths of up to or exceeding 15 km (9 mi). When drilling hard crystalline rock, today's rotary drilling requires time-consuming and frequent "trips" to pull the "drill string" (pipe) out of the hole to change out worn drill bits. Emerging hybrid contact-drilling innovations like hammer drills and particle drilling (e.g., those from NOV and Particle Drilling Corporation) have begun to progressively increase penetration rates. Moreover, recent advances in contactless energy drilling methods (e.g., those of Quaise, GADrilling, and Tetra Corporation) should require far fewer trips out of the hole. Such innovations promise to increase the speed of drilling, reducing drilling costs and making deeper and hotter wells more accessible and affordable.

Laboratory tests with emerging contactless drilling demonstrate that such non-mechanical energy drilling methods, which are yet to be tested in the field, can soften or melt rock through energy directed downhole. Two principal energy drilling methods that are currently being designed for superhot temperature drilling are plasma drilling and millimeter wave drilling (see box). GA Drilling (Slovakia) is preparing to test its Plasmabit drill in the field in the coming year, while Quaise (Houston) is developing an MIT- proposed millimeter wave drill at Oak Ridge National Laboratory. ENN, a private company in China, has also evaluated both plasma and millimeter wave energy drilling methods in a recently constructed rock mechanics laboratory. Other methods being developed include Tetra Corporation's pulsed electronic discharge drill, which has been tested in hard sandstone and is expected to do equally well in granite, and NOV/Particle Drilling Corporation's particle drilling bit, which is now being tested in the field.

Thermal Reservoir Creation

Creating thermal reservoirs in fracture systems in dry superhot rock while avoiding seismic risk is a critical challenge that must be addressed to achieve widespread commercial success. Injected water (without the fracking chemicals used in oil and gas) must be able to flow from an injection well through fractures in the deep rock to absorb heat before being pumped back up through production wells. In this process, engineers will dilate existing fractures or create new ones using new technologies such as thermal fracturing or hydroshearing.

As mentioned above, FORGE Utah remains focused on reservoir creation, increased drilling efficiency, and developed methods for seismic avoidance in lower-temperature hard rock engineered systems.[30] Meanwhile, in Japan, the JBBP geophysical research team is investigating the plastic properties of superhot rock, which may allow opening existing fractures while minimizing seismic risk.[31] Similarly, New Zealand has been conducting investigations into the "brittle-ductile transition" (BDT), a region where the rocks become "ductile"—that is, less brittle and more plastic. Modelers and seismologists suggest that the BDT has inherently lower seismic activity and lower risk of induced earthquakes.

In addition to circulating water through fractures, engineered geothermal methods are also being explored to use drilled subsurface conduits for heating water and returning it to the surface, thereby avoiding use of fractured systems and possible seismic risk. These systems are designed to circulate water in a closed loop through the rock and then back to the power production plant at the surface. Two companies, Eavor and Greenfire, are presently testing their closed loop technologies.[32] Eavor, which is developing its Eavor-Loop™ and Rock Pipe™ "underground radiator," has launched demonstration projects in Calgary, Germany, and New Mexico. In New Mexico, the Eavor-Deep well is being directionally drilled (Fall 2022) to target greater than 5 km and 300 C in granite using Eavor's proprietary method to cool the drill string and bottomhole assemblies.

Figure 10

Left: Iceland Deep Drilling Project drill rig at IDDP 2 in Reykjanes Iceland (source: https://iddp.is/); Right: Steam from IDDP-1 Krafla well test which indicates 36 Mw from a single well (Courtesy, Dr. Gudmundur Olaf Fridleifsson).

Well Construction

Well failure is a principal reason that early superhot rock efforts have yet to succeed. The deep, hot conditions required for superhot geothermal require innovations in metallurgy and cements for more robust casing of wells. Casing, the pipe that holds the rock of the outer borehole in place, prevents the loss of fluids into the surrounding rock and maintains pressure in the well. Casing and cements are typically designed for conditions in the range of 150-300°C. Wells drilled into hot and superhot conditions have begun to advance well construction materials engineering, and new alloys and polymers are being developed that can maintain strength at high temperatures and pressures. One such innovation being tested is the Eavor "Rock Pipe", an applied synthetic borehole rock sealant.

Downhole Tools & Power

Critical barriers to hotter and deeper drilling are tools and downhole power that can function at high temperatures. Failure of tools has been a significant issue at the FORGE Utah project and is an immediate need for advancing successful deeper hotter projects. Such monitoring tools will be necessary to identify fracture and permeability zones and to ensure well integrity during well construction and ongoing maintenance. Current sensors and electronics used to monitor wells are limited by high temperatures and downhole power availability. Research and demonstrations are underway on cooling systems for drilling (e.g., Eavor- Deep, mentioned above), packaged electronics (e.g., surrounded by protective polymers), downhole sensor cooling systems, and new electronic materials that can better withstand the high heat and pressures that will be encountered in superhot rock environments. Moreover, the Norwegian energy research organization SINTEF has developed a method for insulating electronics that have a 300°C limit such that they do not exceed 210°C, tested in a specially developed furnace that heats to 450°C.

Successful superhot rock energy will also require transmitting power downhole for several purposes. First, conduction of power downhole will be required for energy drilling. Plasma and millimeter wave drills will require significant amounts of energy to drive the cutting bits at the bottom of the hole. This is a critical challenge for successful energy drilling because the current limit for today's instruments is about 250°C; electronic cables do not function at temperatures above 350°C.[33] Second, power will be needed for operating wireline logs and other tools in superhot wells.

Surface Power Production

At the surface, production of electricity from early superhot rock plants will likely come from utilization of superhot steam (rather than direct use of supercritical water), adapting existing high-pressure, high-temperature steam turbines, with adaptations for corrosion resistance and for managing possible deposition of silica. For future power generation directly from supercritical resources, insulated tubulars will likely be required to maintain the supercritical state from the reservoir to the surface in the production well.

Advanced Rapid Drilling Methods

Methods to drill rapidly and ultra-deep are key to engineered geothermal systems and unlocking geothermal "everywhere." One area of innovation that is key to managing the cost of drilling is "rate of penetration." Several companies are focusing on improving the speed of drilling with new technologies. One promising area of research and development is energy drilling, which will eliminate the need to rotate a drill bit to grind the rock in the deep subsurface. One of the chief advantages of energy drilling is the much reduced need to remove or "trip" the drill pipe string out of the hole to change a drill bit. Reduced tripping combined with a rapid rate of penetration and no rotation of the drill string promises to substantially improve the capacity for, and economics of, super-deep drilling.

GA Drilling's PlasmaBit drilling technology emits a stream of plasma—extreme heat energy formed as electrons are stripped off of atoms using a high-voltage electric current. GA Drilling is currently engineering its drill to operate as a pulsing plasma "hammer." The drill will be powered by a mud-cooled cable, enabling operation in extreme superhot rock temperatures.

Photos: GA Drilling, Slovakia)

Quaise Energy has designed a millimeter wave drill that is being tested at Oak Ridge National Laboratory. If successful, it will be the first demonstration of drilling a borehole through full rock vaporization. Quaise Energy ultimately aims to reach 10-20 km (6-12 mi) in depth with its drill.

Photo: Quaise, Houston, Texas

NOV and Particle Drilling Technology are field testing their particle drilling/polycrystalline diamond compact (PDC) hybrid bit designed to provide faster, deeper drilling in hard crystalline rock. An intense stream of hardened particles removes 80-90% of the rock and then the PDC cutters remove the remaining rock and provide stability and a smooth borehole.

Photo: Courtesy, Particle Drilling Technologies

SECTION 3

A Path Forward

3.1 Proof-of-Concept Pilot Demonstrations

Successful pilot demonstrations of superhot rock power generation will be key to attracting the large-scale investment needed to move superhot rock to terawatt scale. Successful pilot demonstrations in dry rock must be followed by commercial demonstrations that move superhot rock into the realm of utility-scale power operations. This is not an entirely new endeavor; superhot rock energy research and development has been underway for several decades. Projects in Iceland, Italy, and elsewhere have already contributed to superhot rock proof-of-concept by reaching superhot (supercritical) fluid temperatures and pressures in natural superhot hydrothermal resources at existing geothermal fields —and need to be continued. For example, IDDP's Krafla well (Figure 10) demonstrated an order of magnitude (10x) larger energy production potential for superhot wells as compared to nearby conventional geothermal wells. This project is being extended in the current Krafla Magmatic Test Bed (KMT) project. These projects have also provided important test beds for drilling, well construction and superhot fluid handling. Next steps will include successful well completions, bringing the resource to the surface for power generation in adjacent existing plants or in modular power generators. At the same time, other global superhot rock demonstration efforts must invest in drilling, well completion, and production of energy in dry rock, where there is no superhot hydrothermal resource at depth. The inability of downhole tools to function at higher temperatures has limited the successes of EGS projects such as FORGE. This is an immediate and critical need.

Cracking the superhot rock code will require solving the additional engineering challenges specific to dry rock, particularly aseismic heat reservoir development. These initial pioneering projects can be drilled with today's mechanical drilling technology, targeting regions where shallow heat exists (Figure 12 and red shaded regions in Figure 13). These pilots will provide critical proof-of-concept for "geothermal everywhere." To speed the process of learning by doing, many wells must be drilled. An ambitious goal would be to move a half dozen pilot power demonstrations forward in the 2020s, transitioning to larger commercial demonstrations (e.g. 50-100 MW) in the late 2020s

Figure 11

A quiet revolution is underway as a result of a confluence of innovations in all aspects of geothermal, informed by unconventional oil and gas technologies (such as directional drilling and drilling multiple wells from a pad) and inspired by the recognition of the vast potential of engineered geothermal systems. Superhot rock can be commercialized and scaled up in several decades if adequate resources are invested in the 2020s (akin to other zero-carbon resources) to drill many wells across the globe, leading to rapid innovation and commercialization in the 2030s followed by scale-up in the 2040s.

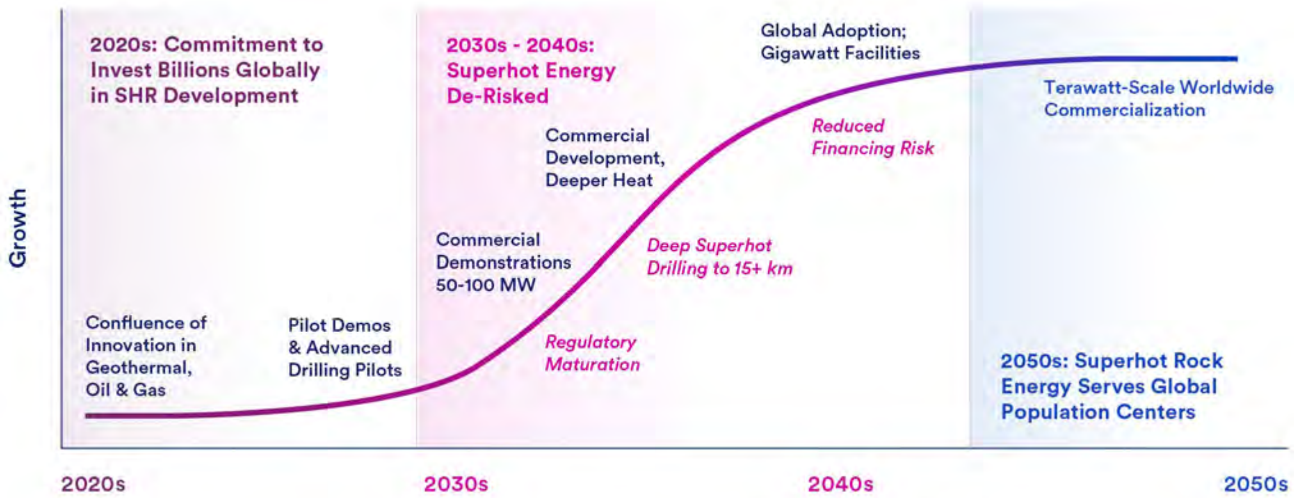


Figure 12

Early power production demonstrations using mechanical drilling in relatively shallow superhot dry rock near magmatic/volcanic regions should be prioritized by governments for funding and be followed up by intensive drilling campaigns. These demonstrations could initially take advantage of existing steam-power production facilities and transmission lines.

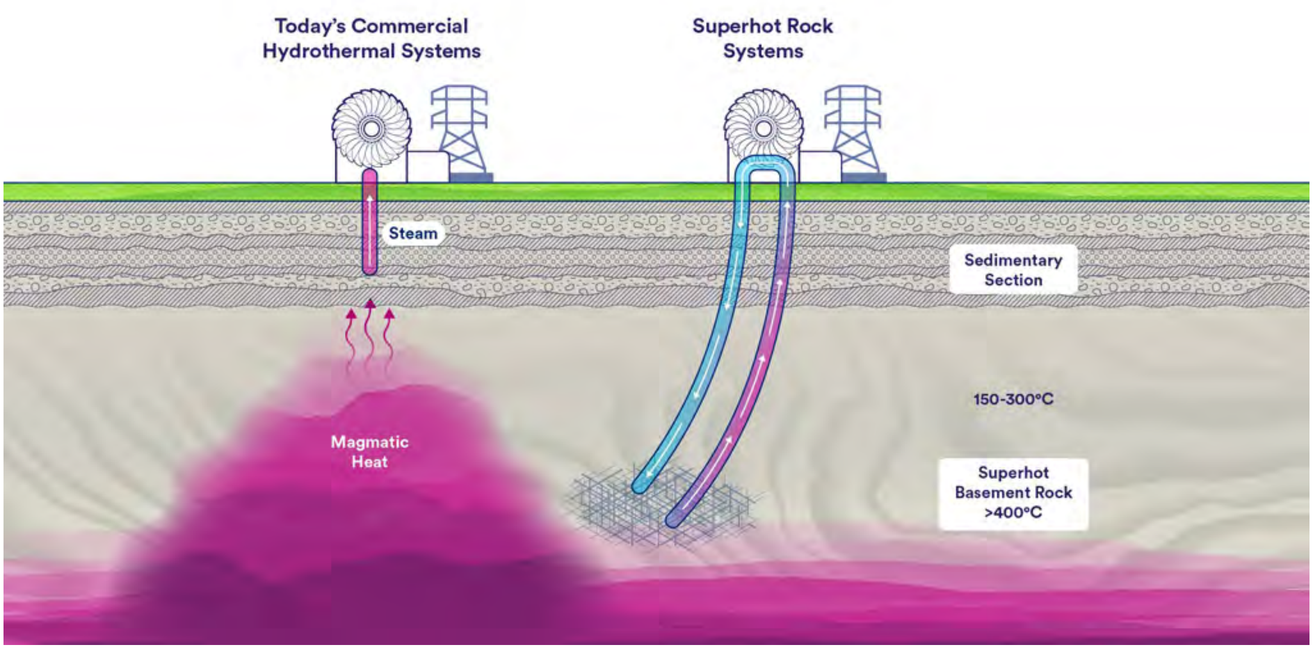
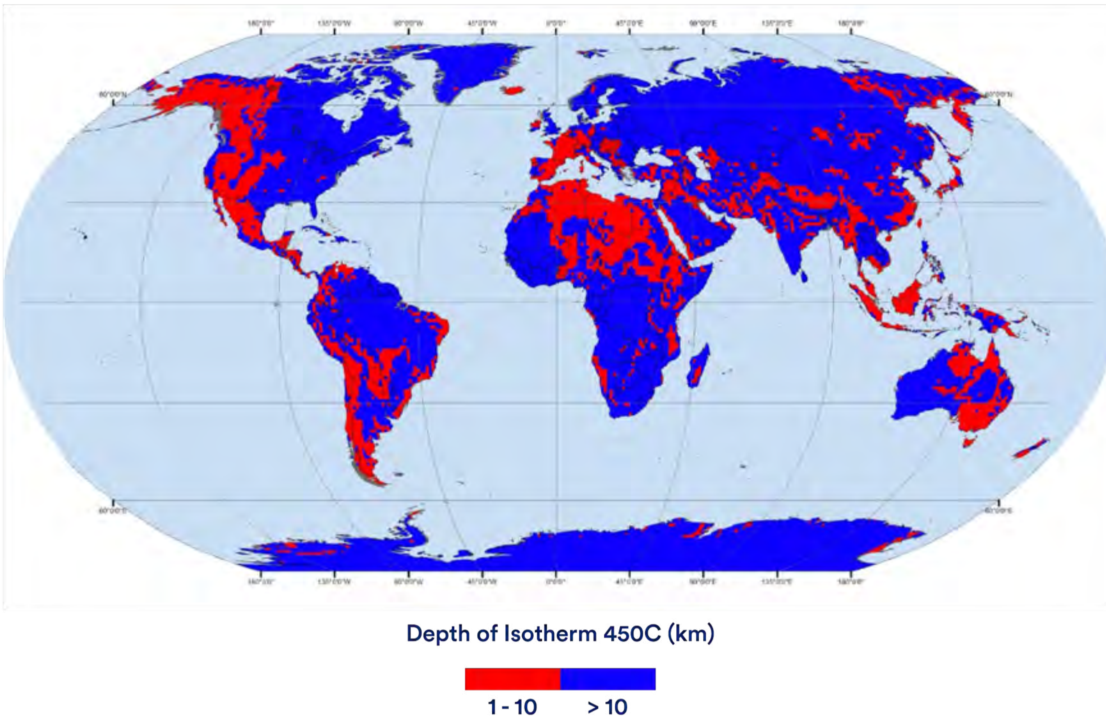


Figure 13

Why superhot rock energy matters: regions in red (roughly depicted) may have accessible superhot rock resources (>450°C) shallower than 10 km in depth that might be accessed with today's enhanced mechanical drilling methods. Advanced drilling methods are being developed and tested that may be able to reach much deeper depths highlighted in the blue regions (Map: Pacific Northwest National Laboratory).[34]



and early 2030s. Potential candidate areas might include, for example, the western United States, Eastern Europe, Africa, Japan, New Zealand, and Oceania, among many other regions.

One particular project of interest is the AltaRock Energy project at the Newberry Volcano in the Cascade Mountains of central Oregon, U.S. It is the only such project that we are aware of globally that intends to demonstrate the production of superhot energy at the surface from dry rock. The Newberry project expects to drill and complete its first superhot rock well couplet (an injection and production well combination) with target well depths of 4.5 km and temperatures above 450°C by 2025. The project will test reservoir enhancement methods to demonstrate flowing the first supercritical reservoir. Newberry's heat resource is significant, and with successful demonstration it could be scaled to gigawatts of extractable power in the future. GeoX Energy, another emerging contender in superhot rock, has acquired licenses in Utah, Idaho, and Washington state in the U.S. Its goal is to produce energy from the supercritical resource by drilling deviated (horizontal) wells using a subsurface heat exchanger.

3.2 Commercial Demonstrations and Deeper Drilling Toward Geothermal Everywhere

Following successful pilot demonstrations, *commercial* demonstrations must begin producing power at grid scale (e.g., 100+ MW). These projects must also move to progressively deeper resources to realize the promise of geothermal everywhere. Drilling campaigns can drive innovation, build confidence and investment risk reduction, and evolve superhot rock energy from shallower heat resources and magmatic areas to progressively deeper resources toward continental interiors. One approach may also be to explore whether superhot rock conditions exist and could be targeted at mid-depths in "hot granites" that generate heat by radiogenic decay. Hard rock drilling projects that do not reach superhot rock conditions could nonetheless produce some return on investment as EGS projects.

Moreover, for superhot rock energy to successfully scale, it must be economically competitive. This will require continuous drilling, problem solving, investment, and best practices evolution to overcome technology challenges and achieve cost reductions. This broad programmatic approach to superhot rock energy drilling and project development should reduce project risks and costs over time through "learning-by-doing." Some innovations needed for superhot rock are underway or planned by small venture capital-supported and collaborative efforts like Alta Rock Energy, Eavor, Greenfire, GeoX, Fervo Energy, and Sage Geosystems.[35,36,37] Big tech can also play an important role in demonstration and commercialization of superhot rock energy by offering power purchase agreements or venture capital for successful projects that could provide carbon-free energy for rapidly expanding energy-intensive operations like data centers.

3.3 The Role of Unconventional Oil and Gas Expertise

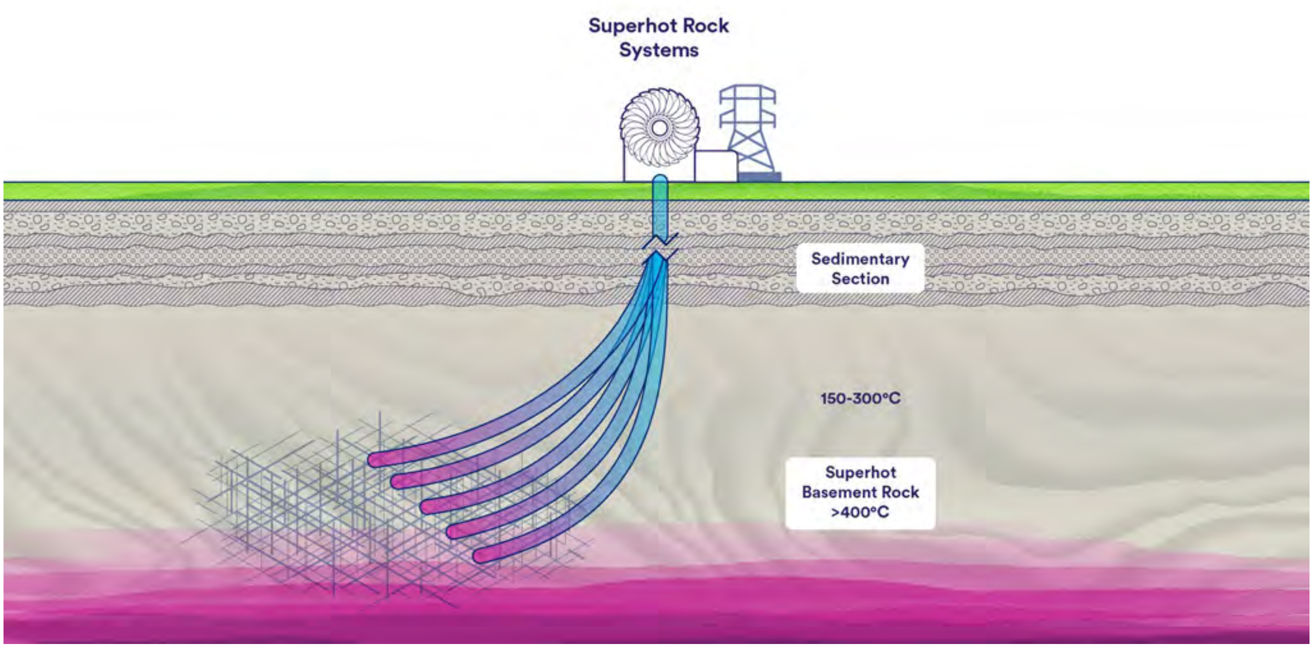
The geothermal industry is striving to incorporate learning from oil and gas into its exploration methods. As far back as the 1990s, Chevron utilized drilling campaigns to drive learning and improve rates of penetration by drilling 90-100 wells at its 375 MW Salak Geothermal Plant in Indonesia. The project eventually achieved 50% cost reduction.[38]

This illustrates how oil and gas industry "know-how" and resources can play an important role in evolving superhot rock energy from proof-of-concept to commercial scale over the next 10-15 years. Superhot rock energy could provide a pivot opportunity that fossil energy companies may need to transition to a decarbonized energy future. Drilling deep into the Earth to produce energy is the oil and gas industry's core expertise, which provided innovations that drove a rapid transformation of shale fossil energy resources previously considered impossible. Some of these innovations included drilling mechanization by mounting a drill rig on rails and systematically moving the rig forward a short distance (e.g., 10 meters) to speed multiple-well project operations and reduce drilling costs and new drill bits to drill faster and minimize trips out of the hole. Directional drilling allowed precise targeting of energy resources and will prove useful to maximize superhot rock energy reservoir energy flows by the ability to optimally orient wells relative to fractures (Figure 14).

Superhot rock energy may also benefit from well-known oil and gas industry strategies for drilling horizontal wells, patterning production wells (e.g., for enhanced oil recovery) to take advantage of multidirectional flow from an injector well surrounded by multiple production wells.

Figure 14

Directional drilling may be a key tool, as it would allow a superhot rock project to: (a) drill from a small surface pad, minimizing impacts and maximizing efficiency; (b) access fractures at angles that allow for better water circulation; and (c) mine heat from progressively deeper heat resources.



SECTION 4

Conclusion: Cracking the Code

Commercial superhot rock geothermal energy could make a transformational contribution to global energy system decarbonization.

Superhot rock energy is poised to be a competitive, high-energy-density, zero-carbon, always-available energy source that could be accessed worldwide in the 2030s with adequate global investment. Key innovations are needed to deploy superhot rock energy widely, including deep drilling, well construction, downhole tool adaptation, and reservoir development in extreme conditions. While technically challenging, these are achievable innovations underway today that could be developed relatively quickly with ambitious public and private investment.

Realizing the promise of superhot rock energy will require the combined resources of the geothermal industry, government laboratories, academic institutions, and the oil and gas industry. Indeed, an intensive drilling and resource development program by well-funded consortia that include oil and gas industry players could provide the knowledge and innovation needed to develop and rapidly commercialize superhot rock energy across the world. Substantial early government investments can jump start the process of commercializing superhot rock energy by providing drilling campaign incentives in promising superhot rock energy locations that differ in depth and geology, as well as by enhancing information sharing and cross-pollination among international projects. The goal should be to learn as much as possible through actual well and reservoir development activities in different subsurface conditions. Such efforts would be enhanced by far more ambitious government support, akin to global support for wind, solar, nuclear power, and zero carbon fuels like hydrogen, and initially spurred by governmental incentives such as write-offs and other meaningful tax breaks.

Moreover, recognizing that permitting can result in long delays, anticipating global regulatory needs and agency staffing early on (such as permitting for groundwater and protecting against induced seismicity) will provide certainty for developers while engendering confidence for policymakers and the public that projects will be safe and will not endanger the environment. Some countries will lack the resources or know-how to independently develop regulations, so one option may be to initiate a global process through the International Standards Organization (ISO), similar to the ISO Technical Committee 265 for carbon capture and storage.

By combining the resources of many countries to underwrite global drilling campaigns in the 2020s, we could crack the code of superhot rock energy such that it could provide terawatts of energy globally in the 2030s—transcending fossil energy and intermittent power, transforming global energy supplies, and providing energy equity and global energy security.

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A Preliminary Techno-Economic Model of Superhot Rock Energy

Prepared for **Clean Air Task Force**
by **LucidCatalyst and Hotrock Research Organization**

Revised
November 2023

CLEAN AIR TASK FORCE

About

LucidCatalyst

LucidCatalyst is a highly specialized international consultancy offering thought leadership, strategy development, and techno-economic expertise. LucidCatalyst specializes in interventions that deliver the critical strategic changes necessary to bring about deep and rapid cuts to carbon emissions worldwide while expanding affordable energy access. As a mission-driven for-profit enterprise, LucidCatalyst prioritizes partnership with clients whose needs are aligned with our broader goals on climate and energy access.

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SECTION 1

Introduction

This revised technical report provides the analytical basis for the levelized cost of electricity (LCOE) estimates described in the November 2022, Clean Air Task Force (CATF) report entitled, *Superhot Rock Energy: A Vision for Firm, Global Zero-Carbon Energy*. This report illustrates that, with engineering innovations in deep drilling, reservoir creation, well construction and downhole tools, superhot rock energy could achieve competitive costs at scale – potentially as low as $20-35 per megawatt-hour (MWh). This would make superhot rock energy competitive in nearly every global electricity market. Combined with its zero emissions profile and ability to tap energy dense heat nearly everywhere means the superhot rock energy could be truly transformative.

The purpose of this technical whitepaper is to provide a detailed description of the superhot rock techno-economic cost model and present the underlying assumptions for estimating constructing and operating costs for a superhot rock project. This cost projection was calculated using a techno-economic cost model developed by the Hot Rock Energy Research Organization (HERO) and LucidCatalyst. It also includes the assumptions and methodology for calculating LCOE, the net present cost of electricity generation over the lifetime of the plant. This report presents the underlying model and provides an update to an earlier 2021 analysis and includes a sensitivity analysis that reflects the change in LCOE based on different input parameters.

Detail is provided such that the reader can easily follow the model structure and effectively recreate the calculations published in CATF's report. Assumptions are transparent so they can be used as reference or interrogated and substituted for others that readers may feel are more suitable.

It is important to note that although supercritical systems have been drilled, superhot rock heat reservoirs have yet to be developed nor have power plants been constructed. Plant costs therefore reflect the best available cost data on constituent systems, components, drilling, and well field development expected to be required. Also, as highlighted in CATF's report, new tools and technologies will be needed to commercialize and scale superhot rock technology. Currently, these advancements are at various stages of development and address critical elements to project development (e.g., geothermal reservoir creation, well metallurgy and cements, downhole power supply and monitoring, and surface power conversion). Even though these innovations are still in development, the model assumes that they are commercially available. Importantly, the cost model does not estimate costs for the First-of-a-kind (FOAK) superhot rock plant (or even the first few plants). Instead, it estimates costs for an "Nth-of-a-kind" (NOAK) plant. Consequently, by definition, these technologies in development are assumed to be available. Estimating costs for a NOAK plant was an intentional decision as such costs are more useful in determining the cost horizon for a particular technology class. It allows for a more meaningful comparison to other incumbent technologies that have known NOAK costs.

This white paper consists of two sections. The first section offers a structural overview of the superhot rock cost model and presents various material input assumptions. The second provides input the assumptions for calculating LCOE and a brief commentary on the value and limitations of LCOE analysis. The reader should note that a separate, companion white paper is forthcoming that estimates the cost of producing hydrogen and ammonia production, two critically important zero-carbon fuels/energy carriers, using the heat and electricity from a superhot rock plant.

What is a NOAK Superhot Rock Energy Plant?

An Nth-of-a-kind power plant reflects the lessons learned in construction and operations from the first commercial plant (as well as the second, third, fourth, etc.) to a point where all potential cost savings/efficiencies are integrated into the project delivery process. A first-of-a-kind plant includes the cost of the initial detailed plant engineering, regulatory interaction, and typically has higher equipment and materials costs and lower labor productivity. Eventually, when the same plant is built by the same vendors and contractors for the same price, that is reflective of a NOAK cost. There is no universally recognized number of plants that need to be built before achieving NOAK costs; however, some literature define NOAK cost as those "achieved for the next plant after 8 gigawatts (GWe) [of deployment]."[1] Others have defined it as "after the technology has been deployed 10 times."[2] For the purposes of the superhot rock model, defining the quantity or capacity to achieve a NOAK plant is less important as understanding that all model costs are derived from peer-reviewed studies that reference NOAK plants.

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SECTION 2

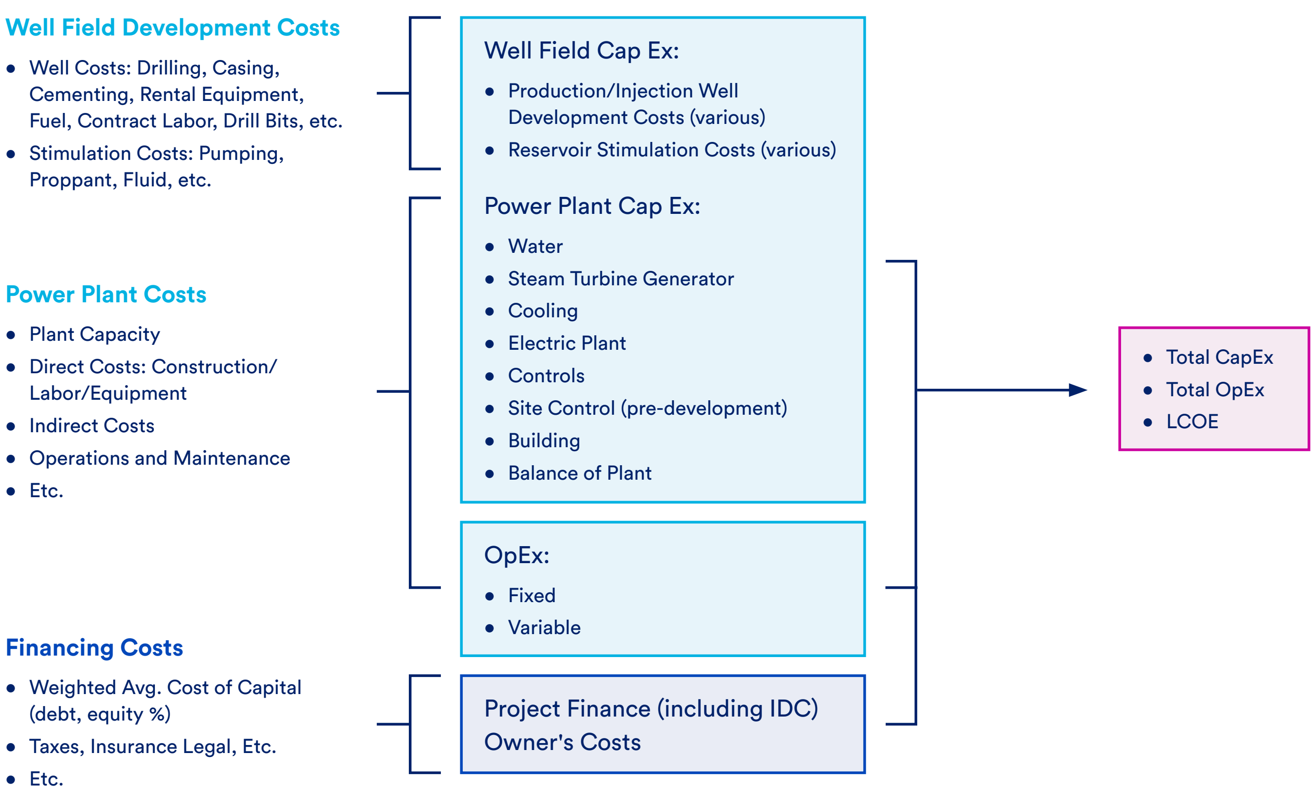
Overview of the Superhot Rock Cost Model

The superhot rock cost model organizes costs into three categories, as shown in Figure 1. These include:

1. **Geothermal Drilling & Reservoir Costs:** all costs related to drilling, casing, and reservoir stimulation.
2. **Power Plant Costs:** all costs for systems, components, and structures on the "power island" used to generate electricity. Specifically, this consists of all costs related to water, steam turbines, cooling infrastructure, power conversion equipment, controls, and the physical site (including all buildings).
3. **Project Financing Costs:** reflects the cost of capital (a mix of equity and debt) to finance the costs from the start of construction through plant commissioning.

Figure 1: Superhot Rock Model Architecture and Input Categories

There are three categories of input costs: 1) Well Field Development, 2) Power Plant, and 3) Weighted Average Cost of Capital (WACC). Each are described on the next page.



2.1 Input Assumptions

The quantity and scope of peer-reviewed, cost literature is relatively limited. Lowry et al. (2017)[3] provided the best available summary of geothermal well cost data and serves as the basis for all well field costs in the SHR technoeconomic model. Lukawski et al.[4,5] provides a superior cost breakdown and yields very similar well cost results, so it is used for reference purposes in this report to show well costs at a more granular level. Geothermal reservoir stimulation costs, which largely consists of pumping, proppant, and fluid ("mud") costs, are not sourced from the geothermal industry, but taken from the best practices in the oil and gas sector.[6] With these qualifications in mind, the geothermal drilling and reservoir development costs reflect the best available data. More data would provide more precision in the results. Fortunately, power plant costs are highly detailed and resolved. For these costs, the superhot rock model pulls from a blend of geothermal and natural gas plants from NTEL (2019). Natural gas plants were included as superhot rock plants are envisioned to be sized and operate more like natural gas plants than conventional geothermal plants.

1) Well Field Development Costs

Well field development costs, which includes activities like drilling, casing, and cementing, etc. are sourced from the 2017 Geothermal Vision Study (Lowry et al.) published by the Geothermal Technologies Office within the U.S. Department of Energy. Reservoir stimulation costs come from the EIA's 2016 Trends in U.S. Oil and Natural Gas Upstream Costs.[7] Several well field assumptions are held constant and listed in Appendices A and B. Table 1 presents the cost breakdown ($/kWe) the primary well field cost categories for a 250 MWe superhot rock plant. As shown a majority are related to drilling activities while almost 20% are slated for reservoir stimulation.

Lowry et al. (2017) publishes a well cost curve based on depth for small and large diameter bore holes, as well as vertical and directional drilling. The cost curves were developed in the proprietary Well Cost Simplified (WCS) model developed at Sandia National Laboratories. While WCS is not publicly available, the cost curve formulas can be found within the code of the GEOPHIRES model.[8,9] These curves estimate well development costs by depth and are employed in the SHR techno-economic model. As mentioned above, the costs in Lowry et al (2017) rely on costs published in Lukawski's 2014 and 2016 publications, which offer very similar cost results. Because Lukawski provides a more granular cost breakdown, for reference purposes, this breakdown is highlighted in Figure 2. As shown, completion costs for geothermal wells, cementing and casing, appear to be roughly equivalent to drilling costs. In the case of superhot rock, completion costs may be higher than drilling costs. This is because new types of cement and casing alloys may be needed to complete these wells at higher temperatures and pressures. However, is it not yet clear whether more advanced cements and steel alloys will be needed. Recent advancements demonstrated in FORGE demonstrate that these wells will be able to use polycrystalline diamond compact (PDC) bits for hard rock, significantly increasing drilling rates, yet further innovations are being tested and proven in the field such as hybrid particle drilling with PDC bits. Therefore, there are both upward and downward pressures on future costs, and this model has elected to not consider either of these factors – at least for the time being.

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3 Lowry, Thomas Stephen, Finger, John T., Carrigan, Charles R., Foris, Adam, Kennedy, Mack B., Corbet, Thomas F., Doughty, Christine A., Pye, Steven, & Sonnenthal, Eric L. GeoVision Analysis: Reservoir Maintenance and Development Task Force Report (GeoVision Analysis Supporting Task Force Report: Reservoir Maintenance and Development). United States. https://doi.org/10.2172/1394062

4 Lukawski, M. Z., Anderson, B. J., Augustine, C., Capuano Jr., L. E., Beckers, K. F., Livesay, B., & Tester, J. W. Cost Analysis of Oil, Gas, and Geothermal Well Drilling. United States. https://doi.org/10.1016/j.petrol.2014.03.012

5 Lukawski, Maciej Z., Silverman, Rachel L., & Tester, Jefferson W. Uncertainty analysis of geothermal well drilling and completion costs. United Kingdom. https://doi.org/10.1016/j.geothermics.2016.06.017

6 U.S. Energy Information Administration (2016). Trends in U.S. Oil and Natural Gas Upstream Costs. Independent Statistics & Analysis. https://www.eia.gov/analysis/studies/drilling/pdf/upstream.pdf

7 Beckers, K.F., McCabe, K. GEOPHIRES v2.0: updated geothermal techno-economic simulation tool. Geotherm Energy 7, 5 (2019). https://doi.org/10.1186/s40517-019-0119-6

8 The cost curves in Figure 6 of Lowry et al. (2017) are available in phyton code (lines 1981-1988) from the GEOPHIRES model, which is accessible at: https://github.com/NREL/GEOPHIRES-v2

9 U.S. Energy Information Administration (2016). Trends in U.S. Oil and Natural Gas Upstream Costs. Independent Statistics & Analysis. https://www.eia.gov/analysis/studies/drilling/pdf/upstream.pdf

The well cost of $22.8M in Table 1 reflects the cost of the first well. The model includes a logarithmic cost reduction curve such that the 10th well is 75% the cost of the first well. This cost reduction is applied to all wells beyond the 10th well; however, the incremental cost reduction between each subsequent well is minimal. This cost reduction curve assumption is consistent with the cost reductions found in the Lukawski (2016) dataset, and is spread out over more wells than the 5 wells needed to reach that same cost reduction in a 2006 Idaho National Laboratory report on Enhanced Geothermal Systems.[10] In the table, this learning curve is reflected as "learning curve elasticity." Drilling and reservoir development costs are determined by the depth required to reach the target temperature and the number of wells needed to reach the required plant capacity.

The model uses the drilling cost correlation from Lowry et al. for a vertical, open hole with a large diameter well bore.

The cost curve formula is the following:

$$y = 0.2818x^2 + 1275.5213x + 632,315$$

Equation 1. Cost curve for vertical geothermal well as a function of measured Depth. Y is cost of the well and X is measured depth. Equation was sourced from code in GEOPHIRES model, which reflects cost curves in Lowry et al. (2017).

As stated, this cost curve was originally derived from the Well Cost Simplified model developed by Sandia National Laboratories. The figures in Lowry et al. present costs to 7,000m. Using the equation above, the SHR techno-economic model goes to 10,000m.

For further background on determining the power production potential for individual wells, please see Appendix A.

Table 1: Breakdown of Well Field Costs

Wells	Estimated Cost	% Cost of Well	Source
Well Cost*	**$19,152,708**	**84%**	**Well costs estimates sourced from Lowry et al. (2017)**
Stimulation**	**$3,650,000**	**16%**	EIA 2016
Pumping	$1,650,000	7%	
Proppant	$1,000,000	4%	
Fluid	$1,000,000	4%	
Total Well Cost	**$22,802,708**	**100%**	
Cost for All Wells	$206,443,622		
Learning Curve Elasticity***	-0.124938737		
Piping + Valves	$57,504,807		

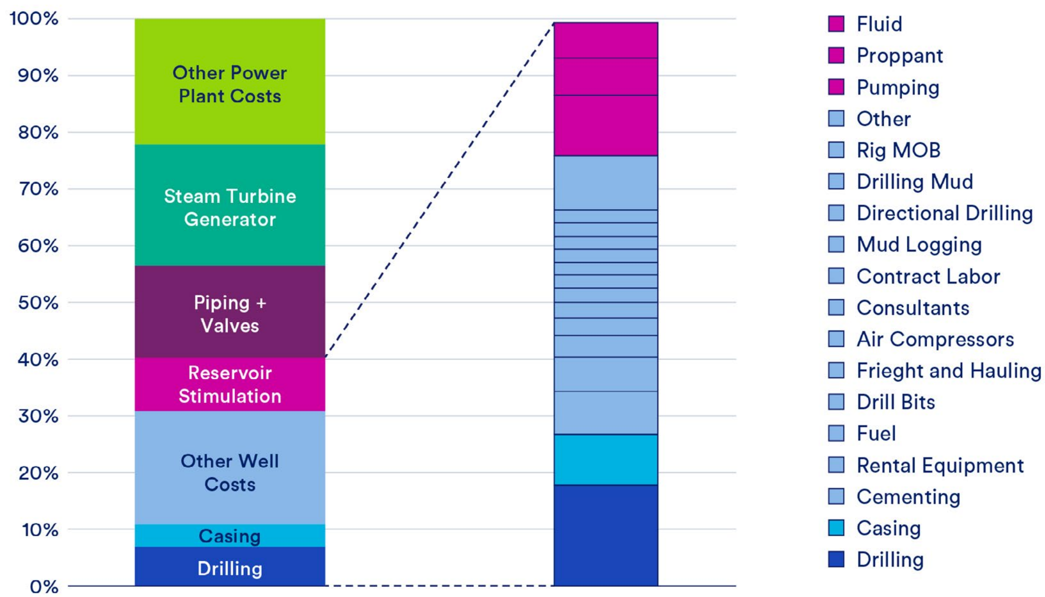
** Drilling costs are sourced from Lowry et al 2017 ("GeoVision Analysis: Reservoir Maintenance and Development Task Force Report"). Specifically, they are taken from the curve fit correlations for the well costs, which were obtained from the phyton code (lines 1981-1988) from the GEOPHIRES model, accessible at: https://github.com/NREL/GEOPHIRES-v2. Drilling costs are correlated to depth. This figure assumes a 6km well at 400°C.*

*** Stimulation costs are assigned by the user. $3.65M is the average cost for a stimulated oil and gas well in the Eagle Ford according to the EIA (EIA, 2016). It should be noted that because no superhot rock plant has been built, there is inherent uncertainty surrounding reservoir stimulation costs. Stimulation costs may be higher than anticipated given the use of FOAK tools in the first few wells. However, like, drilling, it is highly likely that these will come down over time (as the technology scales) and warrant their own cost reduction curve.*

**** Learning curve elasticity defines the logarithmic slope of the learning curve, which reduces well costs 25% from the 1st to the 10th well, and then continues to reduce costs for each subsequent well by a relatively de-minimis amount.*

[10] MIT (2006). The Future of Geothermal Energy: Impact of Enhanced Geothermal Systems (EGS) on the United States in the 21st Century. https://www1.eere.energy.gov/geothermal/pdfs/future_geo_energy.pdf (Figure 9.13)

Figure 2: Estimated Cost Breakdown of a Superhot Rock Plant (by percentage)



2) Power Plant

At the surface, superhot rock plants are largely made up of systems that are common to most thermal power plants. These include steam turbines to generate electricity, a system to cool steam, controls to adjust plant operations, power electronics to make the power useable and reliably dispatched onto the grid, transmission infrastructure, and buildings in which all of these systems are housed. For these reasons, superhot rock construction costs reference data from both geothermal *and* applicable costs from thermal plants.

Instead of averaging the costs for several thermal plants, a cost curve was built based on seven projects, shown in Table 2. These include three combined-cycle natural gas plants and two coal plants from NETL,[11] and two geothermal plants (Mannvitt and an undisclosed plant).

Typically, large plants enjoy economies of scale and can spread capital costs across more MWh over the plant's operating life (leading to lower costs per unit power). Correspondingly, plants with smaller power ratings have higher relative costs per unit power (typically expressed as dollars per kilowatt or "$/kW").

The superhot rock model references the best-fit cost curve highlighted in Figure 3 to estimate the cost for a superhot rock plant in terms of its power rating.

The corresponding regression equation (Equation 2) is below:

$$\text{Power Plant Cost} = \frac{1}{.000153 * MW^{.3334}}$$

Equation 2. Regression fit of power plant cost data provided by NETL, Mannvit and an undisclosed source. Equation used to estimate cost of a power plant as a function of Capacity. MW in Equation 2 means MW capacity.

[11] NETL (2019). Cost and Performance Baseline for Fossil Energy Plants Volume 1: Bituminous Coal and Natural Gas to Electricity. https://www.netl.doe.gov/energy-analysis/details?id=3745

Table 2: Plants Informing Power Capacity Cost Curve

Plant	Steam Turbine Rating	$/kW	Source
NETL NGCC Plant 1	301	884	NETL (2019)
NETL NGCC Plant 2	213	1,105	NETL (2019)
NETL NGCC Plant 3	299	850	NETL (2019)
NETL Coal Plant 1	687	824	NETL (2019)
NETL Coal Plant 2	770	727	NETL (2019)
Geothermal Plant 1	90	1,578	Mannvitt
Geothermal Plant 2	25	2,200	Confidential (HERO)

Figure 3: Power Plant Cost Model

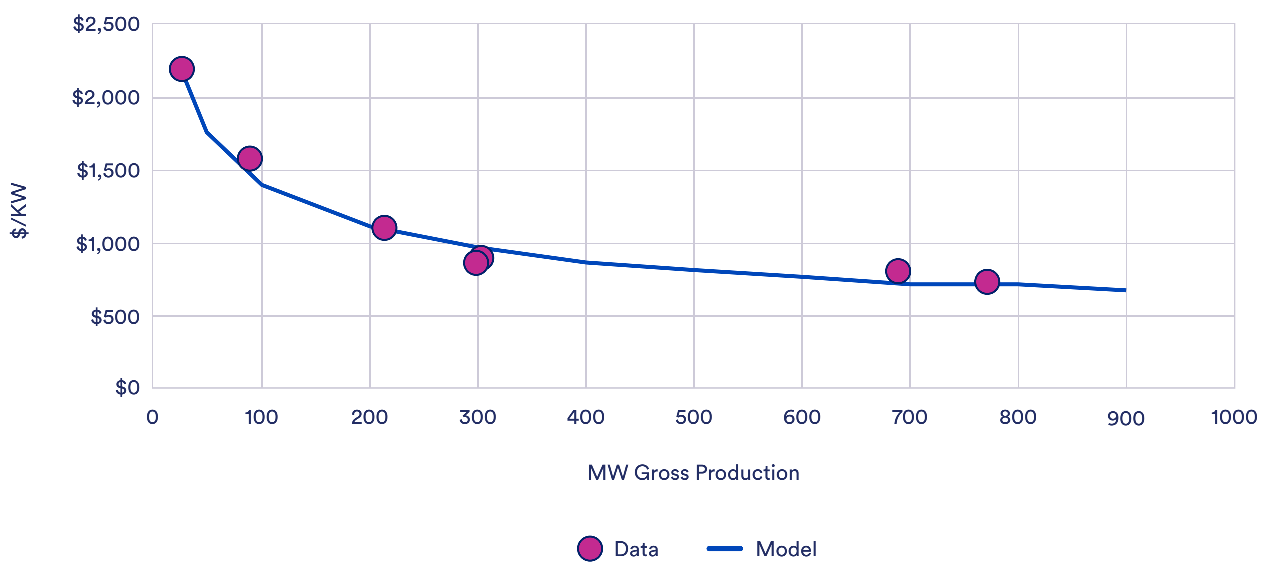


Figure 4 presents a cost breakdown of the major systems following the same best-fit curve methodology. As shown, the Steam Turbine Generator (STG) is the plant component most sensitive to the size of an individual plant, which ultimately translates to a reduction in $/kW. Most STGs are designed for thermal plants (coal and natural gas), which have generally higher capacities (i.e., between 200-600 MW). Smaller STGs can often require custom design and engineering and are consequently more expensive (on a per MW basis).

Superhot rock steam temperatures are assumed to be relatively constant at 400°C, and free of entrained gases.[12] Achieving these temperatures mean that well depths may vary depending on region. With consistent steam temperatures, superhot rock projects are anticipated to be built more like relatively standardized natural gas plants as opposed to bespoke conventional geothermal plants.

Figure 4: Power Plant Cost Model by System

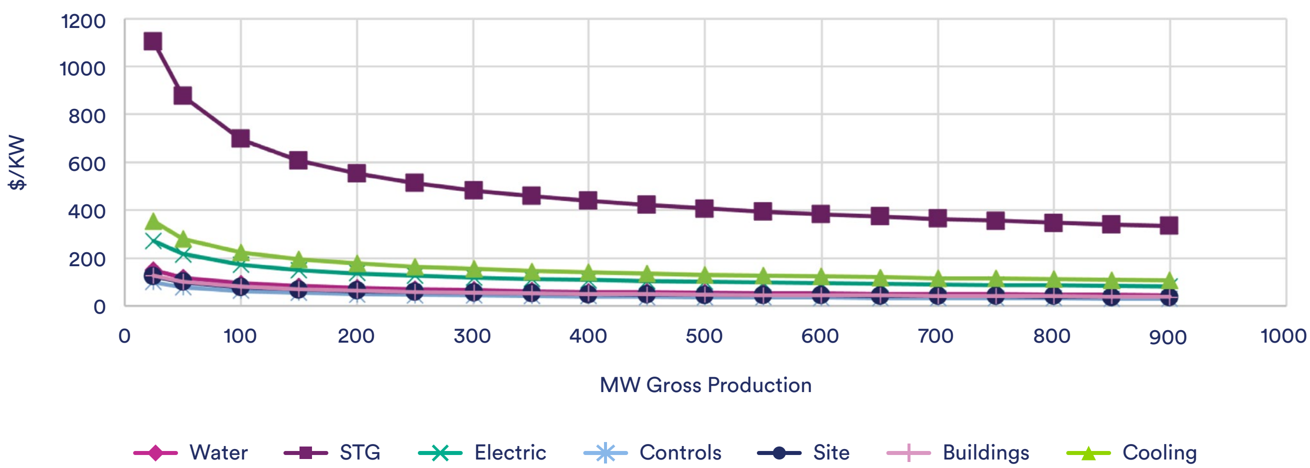
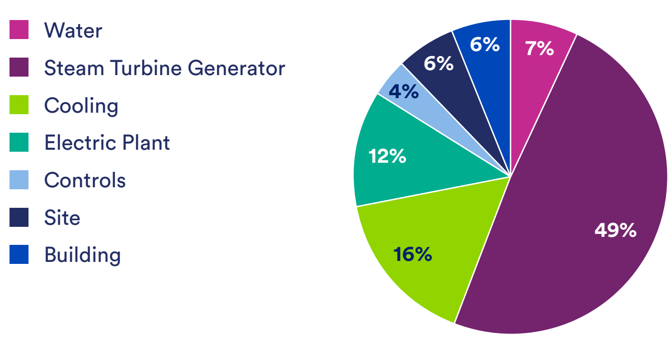


Figure 5: Relative Cost of Each Major Power Plant System (Est.)



[12] Acidic gases can become entrained in steam in hydrothermal/magmatic settings. For example, the Iceland Deep Drilling Project (IDDP) I well at Krafla experienced casing failure as a result of hydrochloric acid entrained in the production steam. When vapor condensed, extremely acidic water droplets corroded the steel casing. In contrast, with the exception of projects on the margins of existing hydrothermal fields, superhot rock will be drilled in dry, generally impermeable rock will not encounter acid gases, reducing risk of corrosion.

Currently, geothermal plants are designed specifically for a particular resource, which typically governs the power rating of a plant. Superhot rock wells produce high-pressure flow and higher-enthalpy (heat carrying) fluids, such as superheated steam and considering that a superhot rock reservoir can be engineered (which is the promise of engineered geothermal systems more broadly) this enables geothermal projects[13] with significantly larger power ratings. Further, it allows for a modular design and construction approach, which can enable significant cost savings in engineering and plant delivery.

Weighted Average Cost of Capital (WACC)

Plant owners will typically finance projects through a mix of higher-risk, higher return equity investment, and lower-risk, lower return bank loan(s) (often called "debt"). Each investor can demand different rates of return depending on their risk appetite. The collective cost of borrowing from all sources represents the weighted average cost of capital or "WACC."

Because the cost model assumes a NOAK plant, the ratio between equity and debt is 30% to 70%, which is relatively typical for investments perceived to be stable (a higher equity ratio would reflect higher perceived risk). Table 3 highlights the model's default WACC assumptions.

As shown in Table 3, the model assumes two tiers of equity – an initial, higher risk (higher reward) tranche with a 25% return, and second lower-risk (lower return) tranche of 14%. Collectively, the return on equity investment is 16%. The debt return is 6%. Assuming a corporate tax rate of 21%, the WACC is 8%, which is not uncommon for a power project that includes well-established technology.

Table 3: Weighted Average Cost of Capital Assumptions

WACC Calculation	
Capital Structure	
Debt to Total Capitalization	70%
Tier 1 Equity to Total Capitalization	5%
Tier 2 Equity to Total Capitalization	25%
Debt / Equity	233%
Cost of Equity	
Tier 1 Equity Risk Premium	25%
Tier 2 Equity Risk Premium	14%
Cost of Equity	16%
Cost of Debt	
Cost of Debt	6%
Tax Rate	21%
After Tax Cost of Debt	4.7%
WACC	**8%**

13 Traditional geothermal power stations produce about 100 MW or less per turbine. This appears to be caused by limited power density seen in traditional geothermal resources, where the available energy per volume of rock/fluid will not allow for greater power plant sizes. The few geothermal power plants above 100 MW are found in either steam dominated reservoirs or high-pressure dual phase reservoirs. These larger resources can be found in places such as in Indonesia, Iceland, the Philippines and other magmatic provinces.

SECTION 3

Levelized Cost of Electricity

The superhot rock model is a basic input-output model where the primary output is levelized cost of electricity. LCOE is a metric used to compare different electricity generation technologies and ultimately inform investment and planning decisions. It reflects the average cost of building and operating the plant over its lifetime, divided by all the energy it generates (expressed in kWh). Put simply, it is the price at which electricity can be sold that enables an investor to break even over the course of its lifetime.

To calculate LCOE, the model calculates the net present value (NPV) of all fixed capital and variable costs and the MWhs produced across the lifetime of the plant. Dividing the total cost by total MWhs yields the LCOE.

The capital and variable costs vary based on the plant's operating capacity, however, for a hypothetical 250 MW superhot rock plant, the net present cost for the wellfield and power plant are approximately $536.4M and $5.4M for O&M, as highlighted in Table 4.

Additional assumptions to calculate LCOE include the following:

- Discount Rate is 8%.
- Plant capacity factor (i.e., ratio of power produced to the maximum possible power produced over the year) is assumed to be 95%.
- The plant lifetime is 30 years.
- All costs are reflected in 2021 dollars.
- Plant construction is assumed to be 2 years. This is akin to the construction schedule of a new combined cycle natural gas plant, which, again, is assumed to be a more appropriate proxy for a NOAK superhot rock plant (than existing geothermal plants). The allocation of capital expenditures are as follows:
    - Year 1 – 30% of power plant is constructed, 70% of well field is development
    - Year 2 – remaining 70% of power plant is constructed, remaining 30% of well field is developed

It is worth noting that while LCOE is a simple, easily understood, and widely used metric, it does have its shortcomings. It tends to oversimply cost, project risk, and other elements related to the cost of capital. There are also other, more practical critiques like how it ignores resource flexibility, resource reliance and resiliency, and negative externalities like carbon pollution. It is important to note that *the model does not incorporate any kind of beneficial tax treatment (e.g., investment or production tax credits) or the existence of a carbon tax or carbon credit market*.

3.1 LCOE for Different Depths and Superhot Rock Technology Regimes

Drilling depths where temperatures are high enough for superhot rock geothermal vary around the globe. In some regions, reaching >400°C will require drilling to a minimum of 3km in depth while and in later projects, it will require going beyond well 10 km in depth. Cost effectively reaching certain depths is dependent on technology availability. With that in mind, LCOE is presented as a function of both drilling depth and two different technology regimes – described below (and highlighted in Figure 6):

- **Accessible with Today's Drilling & Casing Technology:** This reflects temperatures up to 300°C, which is what that today's geothermal projects typically do not exceed. Most conventional drilling and widely available casing technologies are not designed to go much higher temperatures.
- **Advanced Drilling without Casing Needed:** This assumes that high energy drilling technology (e.g., millimeter wave, plasma drilling) shortens drilling times by reducing trips and the ability to 3-D print casing, or displace casing through vitrification or applying an impermeable coating such as Eavor's experimental Rock Pipe.

It is important to note that irrespective of whether energy drilling technology is commercially available, conventional drilling will always be used to get beyond where water is a factor. This will be site-specific, however, for this model assumes this is around 3 km.

Table 4: Superhot Rock Capital and O&M Expenditures (250 MWe plant)

Cost Assumptions			
Well Field	**Value**		**Unit**
Producer/Injector Ratio		2	
Number of Producers		7	wells
Number of Injectors		4	wells
MW/well*		38.63	MW
Learning Curve (% reduction after 10 wells)		25%	
Initial Well Cost Reduction (Technology)		0%	
Cost of First Well	$22,802,708		
Piping + Valves**	$57,504,807		
Total Cost $/kW	$976		$/kW
Total Well Field Cost $	**$263,948,430**		
Power Plant	**Value**		**Unit**
Capacity Input		250	MW
Capacity Actual***		270.4	MW
Service Water System (all the pumps to move water throughout the plant and back into the injection wells)		67.8	$/KW
Stream Turbine Generator		499.2	$/KW
Cooling System (circulating water pumps, foundations, and auxiliaries; make-up water, piping, etc.)		159.8	$/KW
Power Conversion (switchgear and control equipment, generator equipment, station service equipment, conduit and cable trays, and wire and cable. It also includes the main power transformer, all required foundations, and any standby equipment)		123.1	$/KW
Instrumentation and Controls (control equipment for steam turbine, other major components, and signal processing; wiring and tubing, panels and racks, etc.)		44.7	$/KW
Site Preparation, Improvements, and Facilities (offices, labs, roads, etc.)		56.0	$/KW
Building		57.1	$/KW
Total Cost $/kW		1007.7	$/KW
Total Power Plant Cost $	**$272,483,935**		
Total Installed Cost	**Value**		**Unit**
Total Cost $	**$536,432,364**		
Total Cost $/kW	$1,984		
Operations and Maintenance	**Value**		**Unit**
Percentage of Capital Costs****		1.00%	
Annual costs	**$5,364,324**		

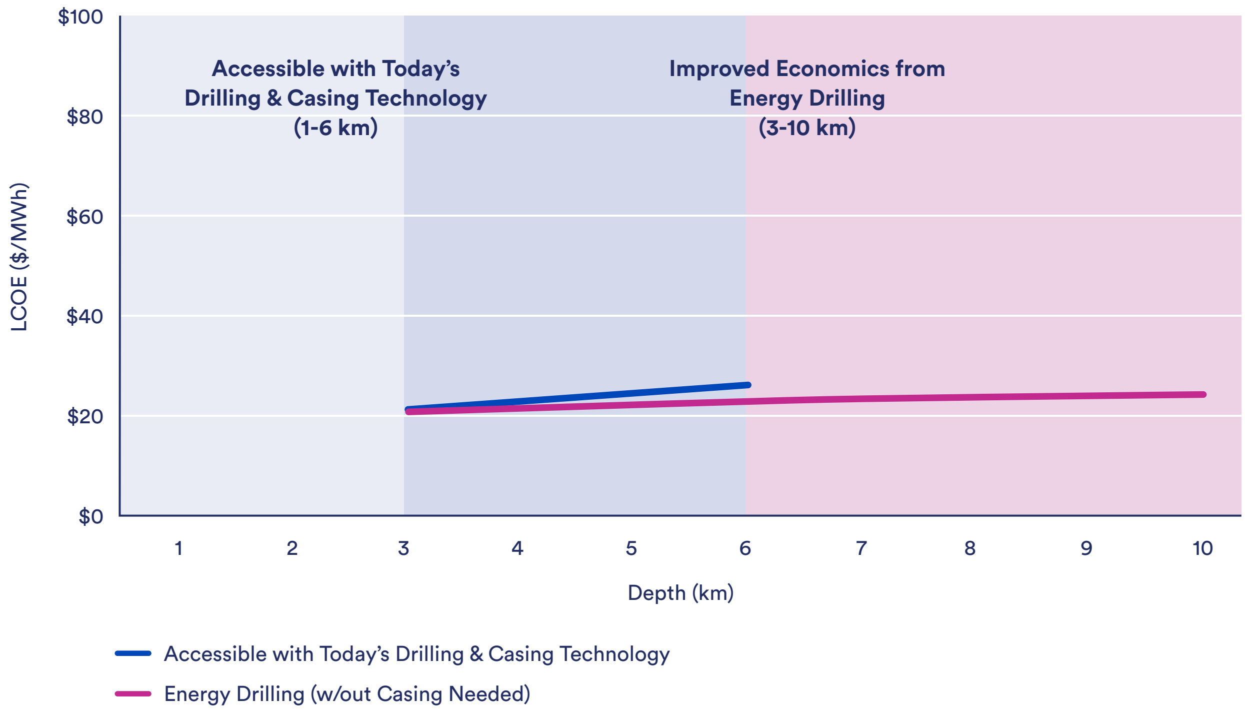
** See Appendix A for methodology on calculating well production.*

*** Piping + Valve costs are a rough approximation based off proprietary data. It scales based on the number of wells, and accounts the valves on the wellhead, the piping into the plant and the separator which knocks out the entrained water from the steam.*

**** The model identifies the minimum number of production wells that are needed to meet the user-defined plant capacity. Most often, the actual production capacity will slightly exceed the user-defined production capacity based on how many MWs are assumed to be produced by each well.*

***** This is a user-defined parameter. A generally accepted percentage is 2.5-3.5% (see: IEA (2010), Geothermal Heat and Power. IEA ESTAP – Technology Brief E07. May 2020), but this reflects significant staffing reductions per MW (due to remote operations reducing redundancies across plants).*

Figure 6: Superhot Rock LCOE by Depth and Technology Regime



Appendix B provides model assumptions for the two technology regimes shown above. This model indicates that a step down in cost will occur once improvements in technology are realized. Without further information, it is difficult to determine if energy drilling will drive the price down further. Also, as the prospective targets for superhot rock energy developments move into deeper and deeper lithologies, the cost is expected to increase linearly.

SECTION 4

Model Sensitivities

The superhot rock model tracks the influence of eight input variables on levelized cost of electricity (the eight variables are shown below). Specifically, the model presents the change in LCOE based on the percent change in one of the eight variables, listed below:

1. **Plant capacity (MW):** maximum rated power output of the plant expressed in MWs.
2. **Decline Rate (%):** rate at which the well productivity declines every year based on heat loss. This is based on the Gringarten analytical model.
3. **Inlet Pressure (MPa):** pressure of the inlet steam entering the steam turbine. This is partially a function of the thermal reservoir temperature.
4. **Depth (km):** depth to the bottom of the production well from the surface.
5. **Flow (kg/s):** describes the rate of heat extraction from the thermal reservoir, one of the most crucial factors in energy production.
6. **Parasitic Load (%):** describes electrical loads such as pumps, fans, controls, and other energy-consuming subsystems of a superhot rock plant that are necessary to operate the facility. Parasitic load losses can be expressed in terms of mass, energy, and exergy flows for various subsystems (e.g., downhole pump, evaporator, turbine, internal heat exchanger, condenser, reinjection pump, etc.).
7. **Learning Curve (%):** an assumption related to the reduction in capital costs after drilling 10 wells.
8. **Operations and Maintenance (O&M) Costs (%):** annual costs as a percentage of total installed capital cost.

Figure 7 highlights the change in LCOE based on the variables above, with several variables are held constant.[14] The most influential variable, by far, driving economics is flow rate, or how much mass flow can be cycled through the superhot rock reservoir (and doing it in such a way that the specific enthalpy is sustainable and decline is manageable). The default flow rate value 55 kg/s reflects a modeled distribution of 28 EGS projects throughout the worldand our belief that this value could be routinely achieved for NOAK projects. It is important to note that flow rate is the least constrained variable in the model and moreover, models to estimate flow have only been recently developed. Several different methods are currently being developed to extract heat from the reservoir, each having its own influence on flow rate. The second most important driver is plant capacity, followed by the learning curve that reduces drilling costs from one well to the next.

The decline rate of reservoir temperature over time was modeled using the Gringarten analytical model. This estimates decline rates assuming a flow of fluid through a homogeneous fractured space between an injection and production wells. Using this model, the average reservoir decline rate over 30 years was estimated at 0.02%. Assumptions for the Gringarten model are listed in Appendix C.

Three additional analyses were run to understand the influence of other variables on LCOE. These included reductions in drilling cost, the change in LCOE from different production well output assumptions (MW), and change in LCOE as OpEx (expressed as a percentage of CapEx) is increased. Each are presented in Figure 8. It should be noted that the reductions in drilling cost figure references drilling costs as a percentage of overall well costs from Lowry et al. (Table 3).[15]

Interestingly, despite the concentration of R&D resourced dedicated to high energy drilling and reducing drilling costs overall, because drilling costs are such a relatively small percentage of overall costs (as highlighted in Figure 2), dramatic reductions in drilling cost do not significantly reduce CapEx or LCOE. The affects that high energy drilling may have on the LCOE could increase beyond these predictions if they precipitate significant reductions in casing and completions.

14 This sensitivity analysis is based on the following, user-defined inputs: Plant capacity: 250 MW; Production well decline rate: 0.2%; Inlet pressure 8 Mpa; Depth to well bottom: 6km; Flow rate: 55 Kg/s; Parasitic load: 4%; WACC: 8%; Learning curve (cost reduction from 1st to 10th well and beyond): 25%; O&M costs (as a % of CapEx): 1%.

15 Table 3 from Lowry et al. (2017) references a 5km well and drilling costs are assumed to include drilling time (6.6%), bits (5.22%), and BHA (2.61%) for a total of 14.43%.

One of the biggest drivers of LCOE is how many MWs can be produced through each production well. MW output is a function of flow rate (flow of heat to the surface in the production well) and conversion efficiency of heat to electricity. Figure 9 highlights the reduction in LCOE as MWs per well increases (showing the default MW/well value in the model as well as the highest estimated/observed energy output – from the Iceland Deep Drilling Project's Krafla well).

Figure 7: Superhot Rock Sensitivity Analysis

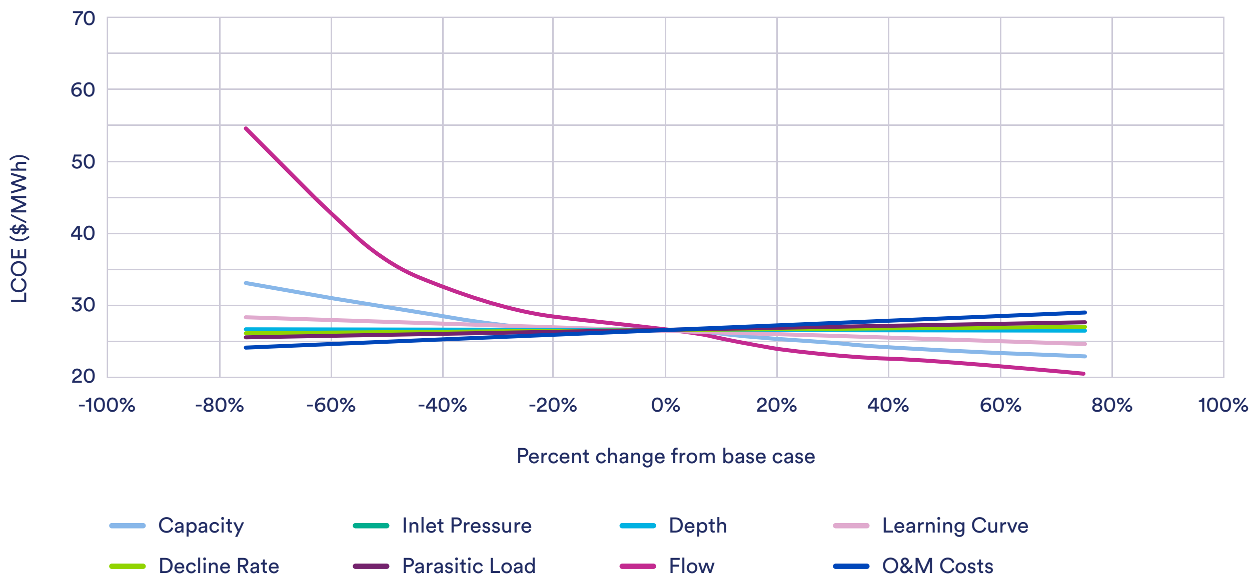


Figure 8: Changes to CapEx and LCOE by Reducing Drilling Costs

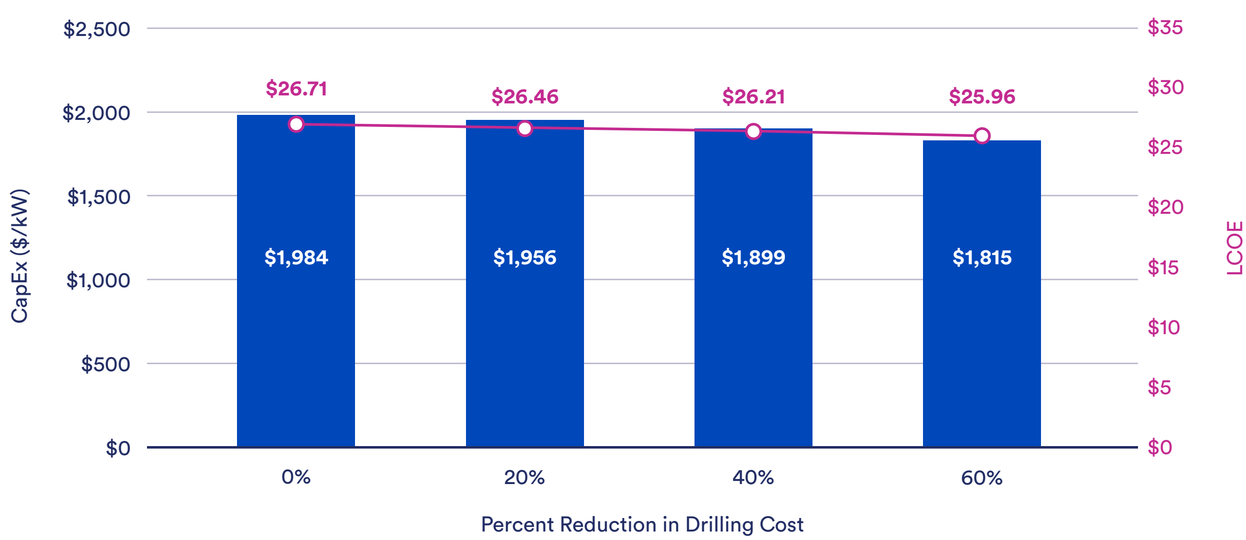
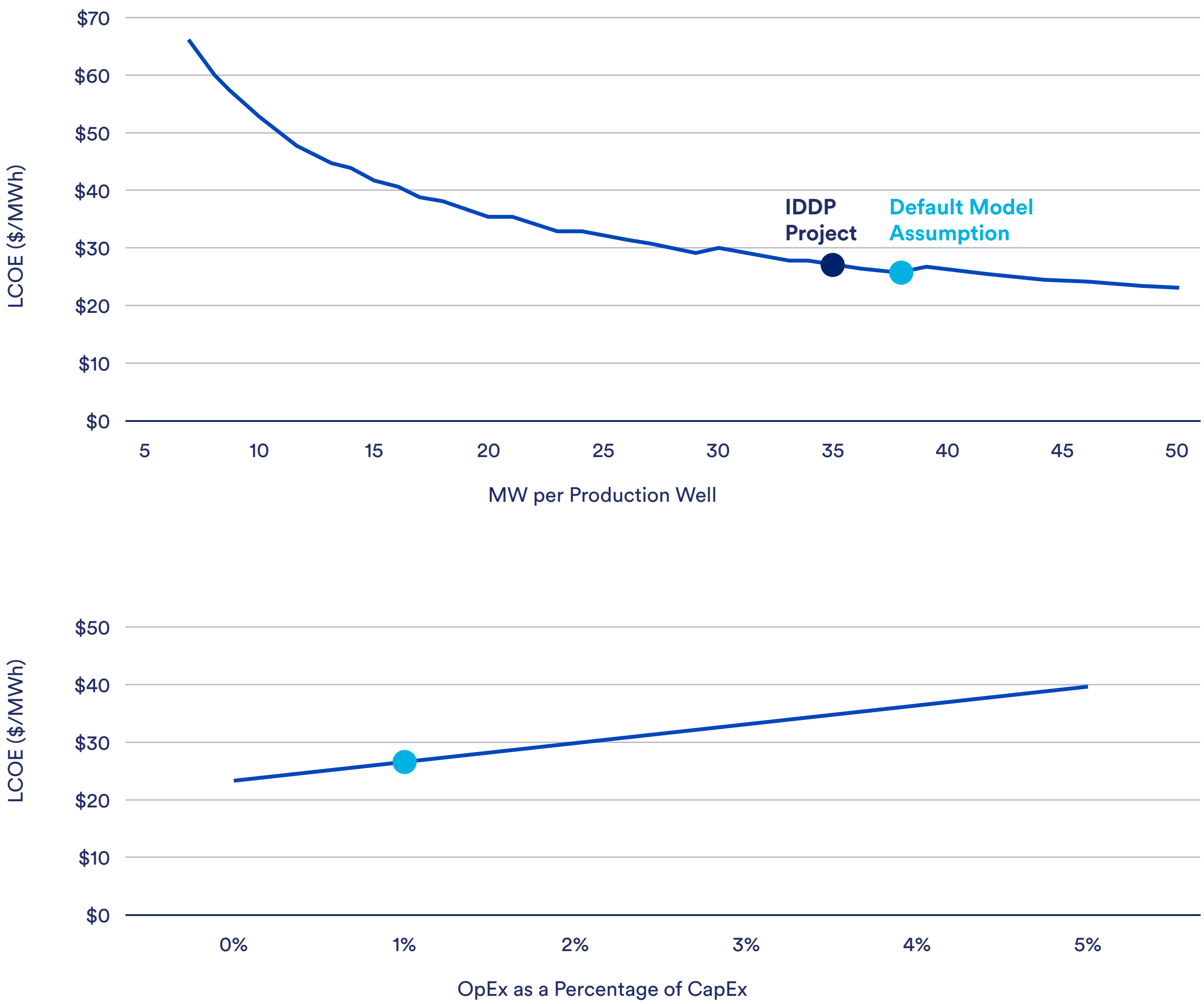


Figure 9: LCOE Sensitivity to MW/Production Well



Similar to the cost of drilling, another interesting finding is the relative lack of significance on LCOE from the displacing of casing with hypothetical borehole vitrification from high energy drilling. Using casing beyond certain depths may increase project risk (not captured in the model), which may translate to cost; however, because the relatively influence of casing cost on LCOE is minor, the cost reduction potential of high energy drilling – as it relates to eliminating the use of casing – is relatively limited.

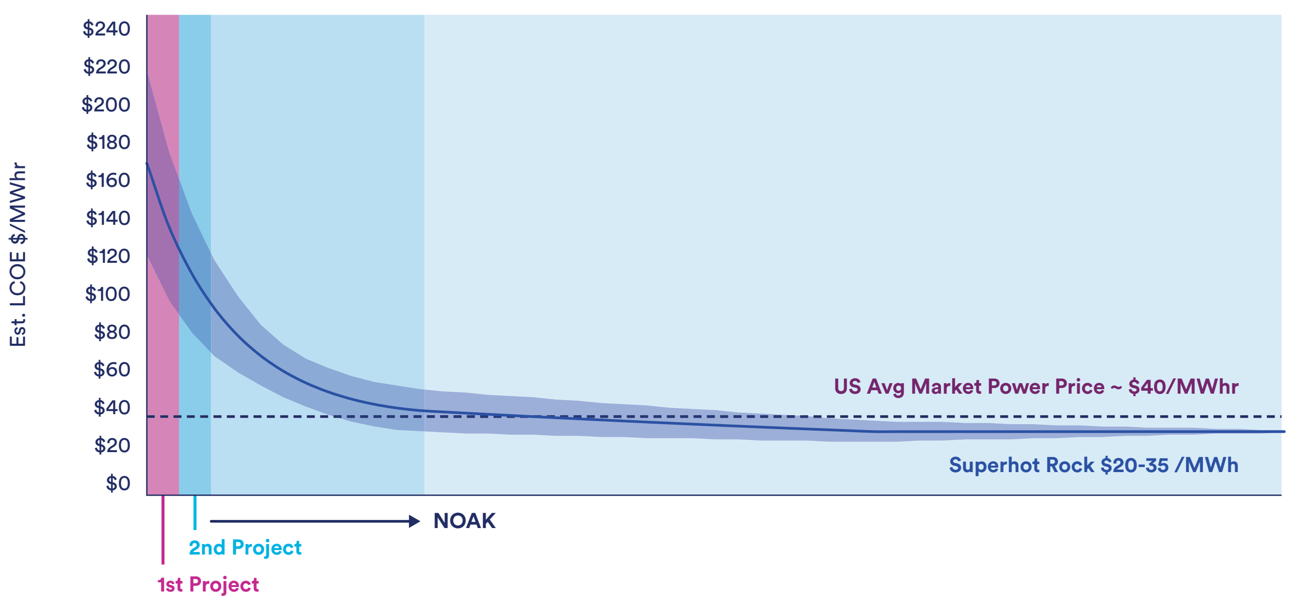
Also note that every energy technology (e.g., solar PV, battery storage, onshore wind, offshore wind, etc.) has its own cost curve. The first plant is nearly always the most expensive, followed by the 2nd and so on. A NOAK model is much more useful when it comes to identifying a technology's scaling potential and future value to the grid. It matters less what the first five plants cost than plants #20-100.

SECTION 5

Conclusions and Considerations

The superhot rock model represents a preliminary attempt to assess the possible competitiveness of superhot rock energy assuming the technical innovations currently in development will be commercially available. The model reveals that, for a NOAK plant, LCOE is predicted at $20-35 per megawatt-hour (as highlighted in an illustrative cost curve in Figure 10 below). This suggests that superhot rock plants could be globally cost competitive with other zero-carbon, dispatchable generation technologies. While we are optimistic about the pace of necessary innovation the timing of these is currently unpredictable, necessarily dependent on the investment in and ability to learn and innovate from drilling many wells.

Figure 10



The results of the analysis suggest successful superhot rock energy has the potential to play an important role in decarbonizing the electricity sector, with the energy density and other qualities needed to pivot from fossil fuels. It is important, however, to be clear about the model is limited by the assumptions and high degree of uncertainty given the low readiness levels (TRL) levels of the component technologies. The major innovations necessary for superhot rock plants to be successfully commercialized – implicit in this exercise – must function routinely in high temperature, high pressure conditions and include:

- Casing and cementing[16]
- Downhole power
- Well logging and coring tools
- Directional drilling tools
- Advanced ultra-deep drilling methods such as energy drilling that minimize drilling downtime
- Thermal reservoir creation
- Management of “felt" or damaging induced seismicity

Such breakthroughs are fundamental to the costs assumed in the model and implicit in a NOAK plant. Further, the assumptions of reservoir temperature, the chemical composition of fluids coming from production wells, or how the reservoir will perform (in terms of heat retention and flow rate, etc.) will require site-specific analysis. Default values for reservoir performance (reflected by variables like flow rate, temperature, and pressure of the production steam) are roughly based on the conditions seen at the Iceland Deep Drilling Project. Moreover, data taken in or near hydrothermal systems (e.g. IDDP) may represent a best case given typical natural permeabilities. Therefore, readers should be mindful that the defaults values represented in the model reflect one of many possible scenarios and that each individual site will be unique.

While the superhot rock model estimates costs based on a set of user-defined inputs, in reality, the marginal cost of a superhot rock plant will likely be driven by two additional factors not included in the model: 1) the number of superhot rock plants in a given region, where developers can leverage the plant design, construction experience of previous projects, and understanding of the subsurface geology and thermal reservoir; and 2) the transfer of learnings in project delivery between regions.

16 Conventional cement is problematic above 275°C (or thereabouts). Temperatures beyond 275°C require formulations other than Portland cement. Phosphate based cement is currently stable to 350°C and past 350°C, but would require modified well completion methods (e.g. packers and expandable couplings).

SECTION 6

Recommendations

To improve the superhot rock cost model going forward there are three variables not currently linked to the estimated LCOE: 1) heat extraction possible from the reservoir rock, 2) years of production, and 3) total available thermal power.[17] These are difficult to estimate without knowing what the reservoir is capable of producing (and consequently how to best orient the injection and production wells). These values should ultimately be tied to LCOE and will be predicated on well and stimulation design – as well as the numerous design decisions that affect how much energy can be pulled from the subsurface (e.g., how many fractures should be created within a given volume of rock, whether to tube insulation or not, whether wellhead pressure should be added, etc.). The model does tie subsurface temperatures, MW output per well, annual heat decline rate to LCOE; however, ultimately connecting the three variables above will allow for even greater precision.

It will also be important to continually integrate the latest published literature on superhot rock-related costs like drilling, reservoir stimulation, and the CapEx for various power plant systems and components. As more data is made available (either through published literature or obtained through private sector companies with intimate knowledge of certain costs), the model will produce estimates with a greater precision. However, it should be noted that more data will not obviate the need for the level of site-specific engineering and modeling work required for project financing. The superhot rock model is meant to highlight the "should cost" for the entire technology class within certainty bounds tight enough to provide meaningful results.

Ongoing EGS projects such as the U.S. Department of Energy, University of Utah FORGE project in Utah, Soultz-sous-Forêts and Rittershoffen plants in north-eastern France, the Newberry project in Oregon (targeting reservoir development and eventual commercial operations >400C), research and development at such universities as the Helmholz Center at the University of Potsdam, Germany, and venture capital funded projects and collaborations such as Quaise, GA Drilling (energy drilling), Eavor (e.g. drilling, completions in hot granite) will continues to provide helpful direction on potential FOAK engineering costs. By understanding the costs of these project in detail, it could help provide additional guidance on how much cost reduction will be necessary to achieve the NOAK costs reported in the model – but also where those reductions need to take place.

17 These variables are within the "Well Output" table in the "Well Field CapEx" worksheet.

APPENDIX A

Well Production Calculations

Estimating the power rating per production well requires understanding the flow rate of the heated steam moving through the production wells and the efficiency of converting that heat to power (MW), or conversion efficiency. The 41.48 MW per production well is calculated by multiplying the flow rate of 50 Kg/s by the Conversion Efficiency of 0.702345115 MW/(Kg/s) – see Table 5.

The flow rate assumption of 50 Kg/s per well is a user defined parameter. Flow rate is likely to be in the range of 30 kg/s - 100 kg/s. The maximum rate of extraction is a function of the density of the fluid being produced. The denser the fluid, the bigger the flow from the producer well. If producing dry steam, 30 kg/s is likely the max flow. However, two-phase and supercritical fluid will enable much higher flow rates-up-to 100 kg/s. These flow rates assume a 7" production string. However, if one telescopes the casing, it is possible to get around some of these flow restrictions but it more difficult to design such a well. To be clear, flow rate is a complex optimization function as it blends well design, reservoir, and power plant constraints. For the purposes of the superhot rock model, a range of 30-100 kg/s with an average expected value of ~50 kg/s (skewed distribution) is arguably the best way to approach this variable. Conversion efficiency is calculated by dividing the amount of energy to do work (309.51 KJ/kg – see Table 7) by 1,000, which is the conversion factor needed to calculate MW/(Kg/s), listed in Table 4.

Table 5: Energy Conversion Calculations

Energy Conversion	Value	Unit
Conversion Efficiency	0.702345115	MW/(Kg/s)
Flow Rate	55.00	Kg/s
MW Output	38.63	MW

Table 6: Enthalpy Calculation

Superheated Steam Enthalpy	Value	Unit
Pressure	**8000.00**	kPa
Temperature	**400.00**	°C
Enthalpy	3139.31	kJ/kg
Density	29.11	kg/m3
Entropy	6.37	kJ/kgK
Vapor Fraction	100	%
IF97 Region	0	
Isobaric Heat Capacity	2.803749556	kJ/kg
Speed of Sound	593.6498659	m/s

Table 7: Well Production Assumptions: Power Generation Efficiency

Power Generation Efficiency	Value	Unit
Calculated Enthalpy	3,139.31	kJ/kg
Reservoir Model Inlet Enthalpy	2,200	kJ/kg
Efficiency Calculation		
For <=2900 KJ/kg Fluid Use: Efficiency = 7.8795*Ln(Enthalpy) - 45.651 Hyungsul Moon and Sadiq J. Zarrouk 2012 For >=2900 KJ/kg Fluid Use: Efficiency = (Enthalpy-2400)/Enthalpy Assuming that Turbine exhaust is 0.15 bar and steam fraction is 91.6% and turbine efficiency is 80%		
Efficiency Calculation		
Input Enthalpy	3,139.31	KJ/kg
Efficiency	23.55	%
Generator Efficiency	0.95	
Work	702.345115	KJ/kg

APPENDIX B

Model inputs for the 2 Technology Regimes

Figure 6 highlights change in LCOE across two technology regimes. The input parameters were kept the same; however, there are basic differences between the two model parameters:

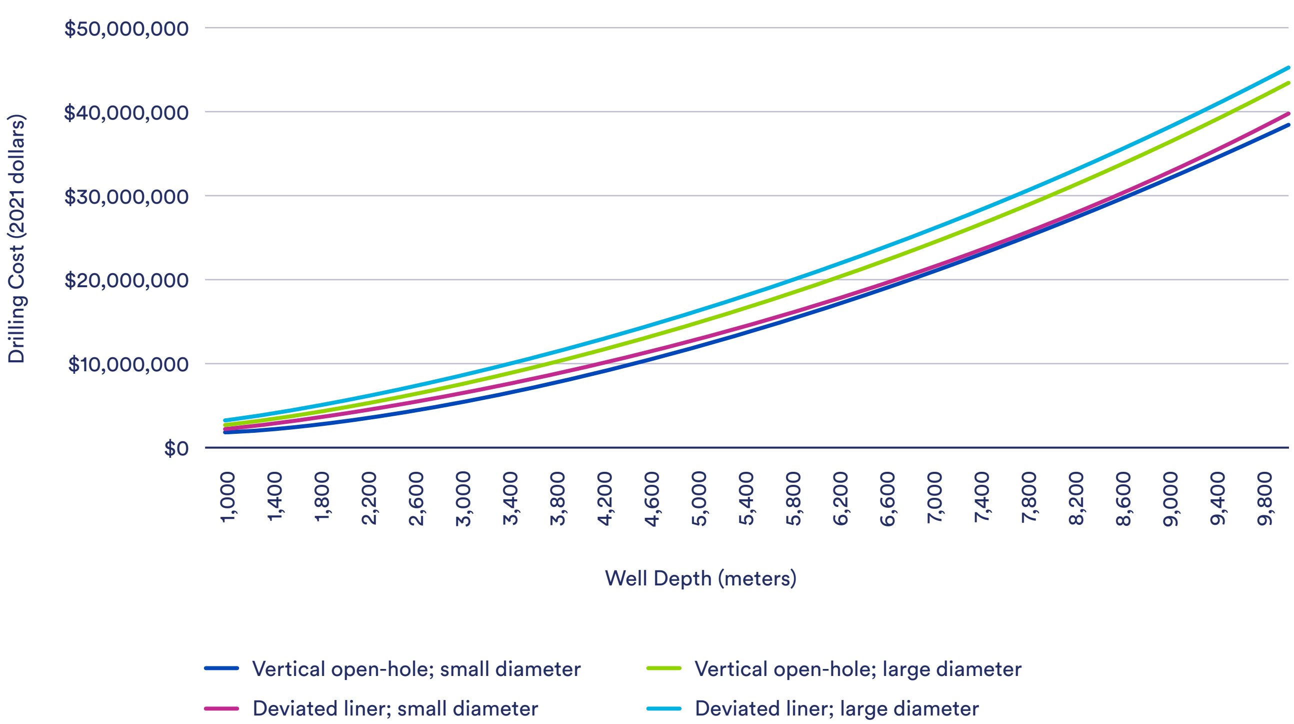
- **Accessible with Today's Drilling & Casing Technology:** assumes that energy drilling is not used at all. Therefore, the well cost estimates follow a formula from Lowry (2017):

  Well Cost = 0.2818×2 + 1275.5213x + 632,315

  - The default cost curve used in the techno-economic model is for a "Vertical open-hole, large diameter"
  - The inflation factor of 103.92% is used to bring 2019 dollars to 2021 dollars
- **Advanced Drilling without Casing Needed:** assumes that energy drilling is ~$1000/meter to drill and create an impermeable wellbore without use of casing and cements.

The model includes a toggle that can incorporate energy drilling, which is assumed to begin at 3km.

Figure 11: Drilling Cost Correlations from Lowry et al. (2017)



APPENDIX C

Additional Drilling and Reservoir Creation Assumptions

Several additional assumptions were made to estimate well field costs and to understand how much geothermal energy can be harvested through a given production well. Each superhot rock project is going to be unique. It will have its own location, a different depth by which to access the required temperatures, a different power rating (which is determined by the number of wells and temperature), etc. Below includes a list of well field assumptions that are held constant in the model (see Table 8), as well as calculations used to determine power plant efficiency (via the energy contained in the steam traveling from the reservoir to the power plant, or the heat content of the system known as enthalpy).

Table 8: Well Field Model Assumptions Held Constant

Reservoir Inputs	Value	Unit
Decline Rate	0.2%	
Temperature	400	°C
Pressure	8	Mpa
Depth	6	km
Distance Between Wells	0.5	km
Production Interval Length	1.5	km
Producer/Injector Ratio	2	
Number of Producers	7	wells
Number of Injectors	4	wells
Well Output	**Value**	**Unit**
Reservoir Rock	Granite	
Specific Heat	1.1	KJ/Kg*K
Density	2650	Kg/m^3
Production Temperature	400	C
Years of Production	30	years
Heat Extraction %	0.092906742	%
Heat Extracted/m^3	1166	MJ/m^3
Production Volume	337500000	m^3
Heat Generation	415.7823269	MW
Energy Conversion	**Value**	**Unit**
Conversion Efficiency	0.70	MW/(Kg/s)
Flow Rate	55	Kg/s
MW Output	38.63	MW

Once the cost of individual well has been made, the next step is to determine the number of wells needed to reach the intended power plant capacity set by the user. This is done by determining the power production for a single well. Equation 3 can be used to estimate the power plant efficiency given the enthalpy of the fluid in the well. The equation accounts for the use of binary, double flash, single flash, and dry steam turbines.[18] The equation does not account for the use of triple flash steam turbines, which are rare because they require high pressures. Also, it should be noted that the SHR model does not include any scrubbing of steam coming from the production well (to remove any corrosive elements before reaching the steam turbine). The model assumes that the steam from the production well is compatible with the steam turbine.

$$\mathrm{Eff} = 7.8795 * \ln(h) - 45.6$$

Equation 3. Describes the efficiency of a geothermal power plant as a function of enthalpy of produced fluid. Eff efficiency and h is enthalpy of the fluid. Equation is from (Moon et al., 2012). Equation generated using production data from 92 power plant from around the world. Equation is only used for enthalpies of <2900 KJ/kg.

One drawback of using Equation 3 is that it can only be used for power plants with fluid enthalpies of <2900 KJ/kg. This is because the dataset used to generate the equation did not incorporate any power plants with fluid enthalpies >2900 KJ/kg and because the relationship between enthalpy and efficiency for dry steam turbines is different than it is for flash turbines. Given limited data, a new method is required to calculate enthalpy for systems with fluid enthalpies >2900 KJ/kg. Equation 3 has been developed to solve this issue. Equation 3 assumes a standard outlet condition with a condenser pressure of 0.115 bar and steam quality of ~92%. These values were derived using data from (Moon, 2012).

$$\mathrm{Eff} = (h - 2400)/h$$

Equation 4. Describes the efficiency for power plants where fluid enthalpy is >2900 KJ/kg. Equation was formulated using a turbine exhaust pressure of 0.15 bar and a steam quality of ~92%. These values were derived using data from (Hyungsul Moon and Sadiq J. Zarrouk, 2012). This equation is predicated on the assumption that an operator can obtain a specific the inlet pressure into the power plant using one of many potential methods. This equation is necessary because Equation 2 did not use data from any plants with enthalpies above 2900 KJ/kg.

This outlet condition correlates to an outlet enthalpy of 2400 KJ/kg. This equation assumes that an operator will be able to reach the inlet conditions needed to produce these outlet conditions while considering the entropic losses of the turbine. Using the calculated efficiency, it is possible to determine the specific work provided by the produced fluid for a specific well. Multiplying the specific work of the fluid with the estimated flow rate provides the total power production on a per well basis.

With the power output of an individual well know, the number of wells needed to reach the intended power plant capacity can be ascertained. The user is responsible for determining the ratio of producers to injectors. The model starts with a ratio of 2 producers to 1 injector. This is because the permeability in many reservoirs is anisotropic. In reservoirs where permeability is more isotropic a user may want to use a different ratio.

In addition to the cost of wells, the model estimates the cost of the gathering system. Equation 5 was generated using confidential data as well as data from the literature, but available data was limited and the equation will be revised as more information is known (Ingason and Sæther, 2018).

[18] Moon, Hyungsul, and Zorrouk, Sadiq J. (2012). Efficiency of Geothermal Power Plants: A Worldwide Review. International Geothermal Association. https://www.geothermal-energy.org/pdf/IGAstandard/NZGW/2012/46654final00097.pdf

$$\text{Gathering System Cost} = \left(\frac{6.5}{1.02^{\text{wells}}}\right) * \text{wells}$$

Equation 5. Shows the cost for a gathering system based on the number of wells. In this equation wells is the number of wells in the field. Output is given in terms of $M of dollars.

Table 9: Inputs to the Gringarten Analytical Model to Estimate Reservoir Temperature Decline Over Time

Gringarten Model Input Variable	Value
Initial Rock Temperature [deg.C]	400
Re-injection Temperature [deg.C]	319
Total Mass Flow Rate [kg/s]	55
Fluid Density [kg/m3]	975
Specific Heat Capacity Water [J/kg/K]	4195
Thermal Conductivity of the Rock [W/m/K]	2.83
Density of the Rock [kg/m3]	2730
Specific Heat Capacity of the Rock [J/kg/K]	825
Fracture Separation [m]	50
Number of Fractures [-]	50
Fracture Width [m]	250
Fracture Height [m]	250
System Lifetime [years]	30
Time Steps	1