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Review article

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Enhanced geothermal systems for clean firm energy generation

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Abstract

Geothermal energy provides clean, steady and renewable electricity and heat, but the use of geothermal energy has conventionally been constrained to locations with adequate subsurface heat and fluid flow. Enhanced geothermal systems (EGS) enable geothermal energy usage in unconventional areas by enhancing the subsurface permeability and increasing fluid flow, which is then extracted as a carrier of the thermal energy. In this Review, we discuss the development of EGS and its role in providing energy. Some EGS are operating commercially in Europe and provide heat and/or electricity, but technical issues and concerns over induced seismicity have historically hindered the broader expansion of EGS. Adaptation of advanced drilling techniques (including the use of polycrystalline diamond compact bits, multiwell drilling pads, horizontal drilling and multistage stimulation) is enabling an increase in scale and decrease in cost of EGS projects. As a result, in the USA, enhanced geothermal is expected to achieve plant capital costs (US$4,500 kW^{-1}) and a levelized cost of electricity (US$80 MWh^{-1}) that are competitive with market electricity prices by 2027. With further development of EGS to manage induced seismicity risk and increase system flexibility, EGS could provide stable baseload and potentially dispatchable electricity in clean energy systems.

Sections

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Key points

- Enhanced geothermal systems (EGS) have the potential to supply clean and firm energy in the form of electricity and/or direct heat.

- EGS projects have been developed since around 1975, with many in Europe. There are larger scale projects currently in development in the USA.

- Several EGS projects operate commercially in Europe. Around 20 well-to-well circulation EGS projects have been developed, but most operate for research purposes or produce modest amounts of energy (a few megawatts electrical or a few tens of megawatts thermal).

- There have been reductions in drilling time and therefore cost in EGS projects developed in the 2020s. Adaptation of oilfield drilling strategies has shortened EGS drilling times by 50–70%.

- Owing to innovation, EGS is expected to be scaled to much larger projects (for example, hundreds of megawatts electrical) at a cost that is competitive with other sources of electricity.

- Induced seismicity is an important issue for EGS, as earthquakes associated with EGS development can impact social acceptance and risk loss of a project's social license to operate.

Introduction

Heat and baseload electricity have been increasingly sourced from geothermal energy during the past 100 years. In 2020, annual geothermal electrical and thermal utilization was equivalent to several days of annual worldwide oil production[1,2]. Some countries (such as Kenya, El Salvador and Iceland) produce from a quarter to a half of their national electrical consumption from geothermal generation[3]. However, there are relatively few regions of the world with the optimal combinations of heat, water and permeable rocks for traditional geothermal systems. Therefore, despite being a steady, naturally occurring source of renewable energy, geothermal utilization lags behind intermittent renewables such as wind and solar. For example, the worldwide electricity production from geothermal sources was about 19 GW in 2023, whereas that from wind and solar was 507 GW (ref. 4).

Enhanced geothermal systems (EGS) can facilitate the use of geothermal systems in suboptimal settings by stimulating permeability and increasing fluid flow through the rock, allowing the thermal energy to be swept out by the circulating fluid. Fluid flow is increased by drilling injection and production wells into hot rock and enhancing its permeability by fracturing or other means[5] (Fig. 1). Hot water and/or steam is then produced to the surface, where it can be used to generate electricity in a steam turbine or binary power plant or for direct heat applications by circulating the fluid through a building or a district heating system. EGS was originally described and patented in the 1970s[6,7]. Drilling started on the world's first large-scale EGS at Fenton Hill, NM, USA in 1974 (ref. 8). By 2020, there had been more than 64 permeability enhancement projects globally[9], including around 20 projects that involved well-to-well permeability creation in unconventional geothermal sites (which is the approach most commonly referred to as EGS, including in this Review).

These projects have mainly been government research projects or commercial operations at a small scale (a few megawatts electrical or a few tens of megawatts thermal), and only a few EGS sites produce energy commercially[9]. However, since 2020, new projects have commenced development at much larger scale, using innovations in technology and substantial reductions in development cost, representing a major change in direction and outlook for EGS projects[10].

In this Review, we address the scientific and technical issues involved in scaling up EGS deployment, focusing specifically on the well-to-well concept. We discuss where EGS has been developed and the kinds of geology that are most suitable. We describe drilling and stimulation of EGS with the least risk of induced seismicity. Finally, we examine the applications and economics considerations of these systems in a transitioning energy system.

EGS locations and geological settings

Successful EGS prototypes have fluid flow mainly in the granitic basement and, where connected through faults or fracture systems to the granitic basement, in its overlying sedimentary cover[11]. Broadly, EGS can be categorized as convective-dominated systems (which have some open natural fractures) or conductive-dominated systems (with few natural fractures)[12]. The two types of systems can require different borehole trajectories, stimulation strategies and geothermal targets. This section examines the settings in which EGS are and could be hosted and the interactions between the natural and engineered fractures that allow fluid to flow.

Convective systems

Convective-dominated EGS are in geologically active tectonic settings and involve naturally fractured rocks that have sealed or poorly connected fractures and therefore need to be stimulated to enhance the flow rate. Then, natural fluids within the fracture system can be circulated via suitable borehole trajectories[11]. Such systems can be found in geothermal regions that are not magmatically active but are in active extensional Tertiary grabens or in outcropping Variscan granites in Europe[12]. For example, very hot deep-seated geothermal systems related to Quaternary plutonic intrusions at conventional geothermal fields such as Larderello in Italy or The Geysers in California and hot active volcanic fields such as Newberry in Oregon are promising EGS targets[12].

Four convective-dominated EGS sites are operational and produce commercial electricity or heat for industrial applications in the Upper Rhine Graben in Europe, which belongs to the European Rift system[11]. There, EGS operational plants have been running between 8 and 16 years continuously, with an operational availability higher than 90% at the Rittershoffen plant[13]. The convective-dominated EGS are characterized by high geothermal gradients in sedimentary formations from the Mesozoic and Cenozoic that overlay a Palaeozoic basement made of fractured crystalline rocks with graben-like compartmentalization. The depths of the geothermal wells in these EGS vary from 2,600 m to 5,000 m and target steep normal faults and their damaged zones that cross-cut fractured granite covered by fractured sandstone and limestone sedimentary formations[11]. The geothermal fluids consist of natural brines with salinity higher than 100 g l^{-1}, which induces deep convective loops within the nearly vertical fracture system. Very high geothermal gradients (>80 °C km^{-1} in the first kilometre) indicate the occurrence of a deep-seated convective-dominated system[11].

In the operational EGS sites in the Upper Rhine Graben, natural fracture characterization has been extensive – exploration wells

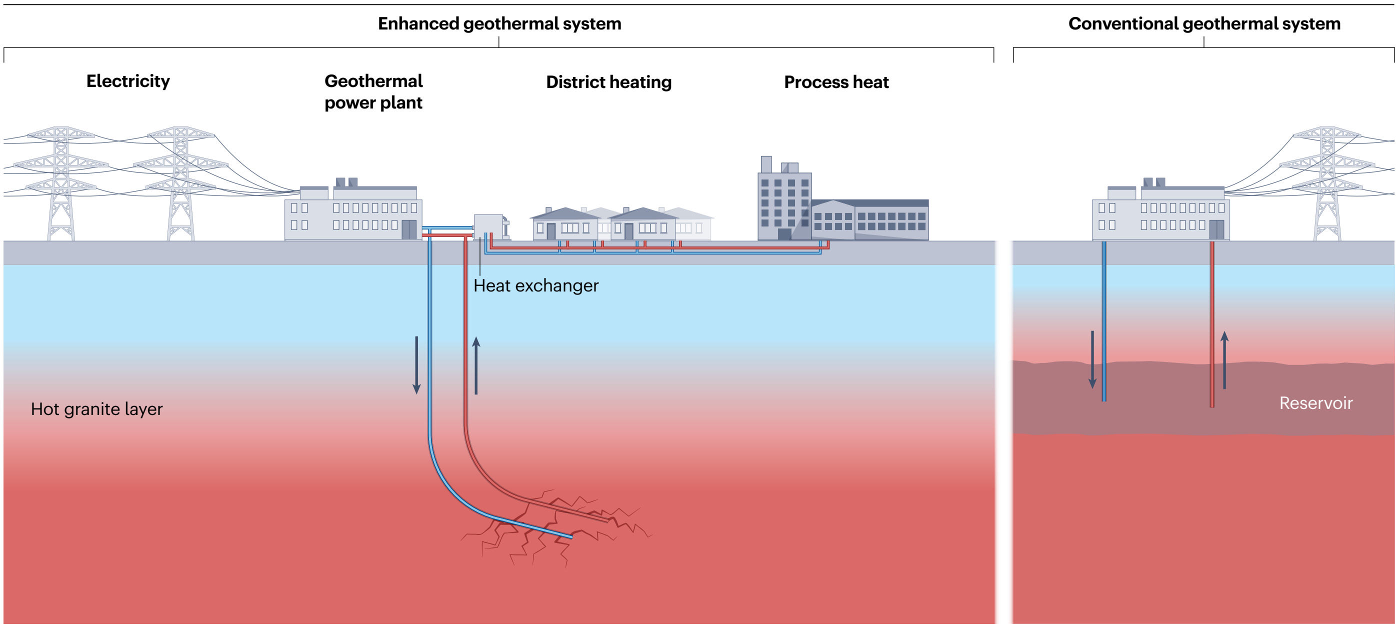

Fig. 1 | Enhanced geothermal systems. Enhanced geothermal systems access areas not suitable for conventional geothermal systems by increasing the permeability of hot rock. Water is pumped from a surface station to a hot reservoir, where it is heated. The hot water is then extracted to the surface, where it can be used for heating and/or converted into electricity. Electricity is often generated through steam turbines or in binary cycle power plants. Conventional geothermal systems also extract hot water and steam, but rely on natural reservoirs and tend to be shallower.

provided 1.3 km of rock samples with more than 3,300 measured natural fractures[14]. Acoustic and electric borehole image logs were used alongside core investigations. Spatial analysis revealed that natural fractures are closely spaced and organized into clusters, forming discrete faulted zones with intense hydrothermal alteration and secondary mineral deposition[15]. Extensive core analysis showed that virtually all natural fractures are filled with secondary minerals, indicating past fluid circulation that eventually sealed them. Owing to the scarcity of permeable fractures in the open-hole sections, wells require stimulation[16]. The fracture system is nearly vertical. However, as the preliminary EGS wells were drilled vertically, the probability that vertical boreholes intersect natural fractures was low and complex stimulation strategies were needed to connect the open-hole section of the geothermal wells with the natural fracture system. In later projects, inclined or deviated wells were drilled into the nearly vertical fracture system that allowed easier connections to the most convective and permeable fractures[11].

Other examples of European convective-dominated EGS projects utilize well-exposed faulted Carboniferous granites in Cornwall, where two EGS sites exist at United Downs and EDEN[17,18]. The geothermal target corresponds to highly dipping faulted zones crosscutting a radiogenic granitic batholith. Owing to the low geothermal gradient, the production well was drilled to a depth of around 5,000 m where temperature range is about 190 °C (ref. 17).

The United Downs project in Redruth targets the Porthtowan Fault Zone, intersected by a 5,275 m deep production well and a 2,393 m deep injection well, with bottom hole temperatures around 175 °C (ref. 17). The Porthtowan Fault Zone is a complex strike-slip fault zone over 15 km long and 200–500 m wide. Electrical and acoustic borehole image logs identified two fracture sets: a major set trending NW to NNW and a minor set trending ENE. Fracture porosity primarily resides in the major highly dipping fracture set. Fracture intensity decreases with depth, but many open fractures persist. The Porthtowan Fault Zone is encountered between 4,100 m and 4,700 m, with active hydraulic structures at 4,890 m (ref. 17). The project relies on shear-enhanced stimulation of fractures to drive fluid flow from the shallow injector to the deeper producer.

In Australia, EGS projects were launched in the Cooper Basin. One convective project is Habanero, where six vertical wells were drilled in this part of the Cooper Basin, reaching about 4,200 m deep and 220 °C at total depth[19]. The system has similar geothermal characteristics to those operating in the Upper Rhine Graben in Europe. These characteristics include evidence of mud losses during drilling operations indicating natural permeability and artesian flow, high geothermal gradients in thick insulating sediments hosting hydrocarbon resources and occurrence of a deep-seated fractured granitic body intersected by local fault zones corresponding to reservoir targets and natural fractures, which are critically stressed and are prone to shearing[19].

European convective systems and those in Australia are different in terms of regional stress. The Cooper Basin is characterized by an over-thrust regime that developed a nearly horizontal network of fractures owing to a minimum stress being vertical[20]. The vertical wells drilled in Cooper Basin were, therefore, suitable for intersecting the nearly horizontal fracture systems, whereas in the Upper Rhine Graben, natural fractures are steeply dipping and thus highly deviated well trajectories are more appropriate for exploiting them. Many hydraulic stimulations and circulation tests were conducted in Habanero, and a binary plant of 1 MWe generating electricity was operated for several months but without a positive economic outcome[19] and the project was ultimately abandoned.

Conductive systems

The second geological setting for EGS prospects, conductive-dominated systems, is in formations with relatively low intrinsic permeability and no hydrothermal activity. In these low-permeability formations, geothermal wells must be stimulated to achieve commercially viable production rates[5,21]. New localized vertical induced fractures can be created using stimulation techniques in horizontal or highly deviated borehole trajectories. Those engineered fractures connect the wells by acting as local heat exchangers for heating injected fluids by conduction[5].

There have been successful conventional geothermal projects in the Basin and Range province in the Western USA, where temperatures range from 200 °C to 250 °C in geothermal reservoirs[22]. Geothermal reservoirs form within a horst of pre-Tertiary basement rocks (similar to the Upper Rhine Graben) and are bordered by vertical faults with up to 400 m of offset[23]. However, it has not always been possible to reach commercial flow rates in some locations of the Basin and Range and the Great Basin more broadly. Hence, EGS could be a good alternative approach in these locations where the primary permeability is the limiting factor rather than heat.

Many conductive EGS sites are found in the Great Basin region of the USA (which includes the Basin and Range). There, pilot EGS projects in Coso, Desert Peak, Blue Mountain and Utah FORGE are in active extensional regimes with normal faulting, low permeability and high regional heat flow[24–26] (Fig. 2). At Desert Peak, the injectivity index is substantially below the typical threshold for commercial geothermal wells, and a nearly 60-fold increase in injectivity was achieved after a series of stimulation operations[27]. However, it was far below the value of 1 l s^{-1} bar^{-1} that was classified as a very good post-stimulation injection well (in Europe, for example, the economic threshold for an injection well is around 2 l s^{-1} bar^{-1} ref. 28). The Utah FORGE EGS site (in Utah, USA) is mainly governed by a low permeability conductive thermal regime[26]. This conductive area is separated from the nearby convective Roosevelt Hot Springs (Blundell) geothermal system by a local fault (Fig. 2). At Utah FORGE, crystalline rocks are faulted and fractured with various orientations, striking NS to EW and dipping from high to low angles[29] and measured permeabilities are less than 30 microdarcies (ref. 26).

Drilling technology and performance

The economic viability of conventional geothermal projects depends heavily on drilling performance. Historically, drilling costs typically account for ~50% of the total project cost and have a substantial role in determining the overall feasibility of these projects[30]. The role of drilling cost in economic viability is expected to also be the case for EGS. However, compared with conventional systems or earlier EGS, more recent EGS projects have advantages that have improved drilling performance and reduced costs, such as at FORGE[31,32] and in Fervo projects in Nevada and Utah[33]. One general advantage is that EGS wells are drilled at designed locations rather than needing to seek optimal geological structures as a conventional geothermal development would. EGS projects typically target geothermal formations with a predictable and uniform temperature distribution at depth, which allows a target production temperature selection and power generation facility optimization early in the project life.

Improvements in EGS drilling performance and cost are largely related to technology[10]. Modern drilling technologies from the

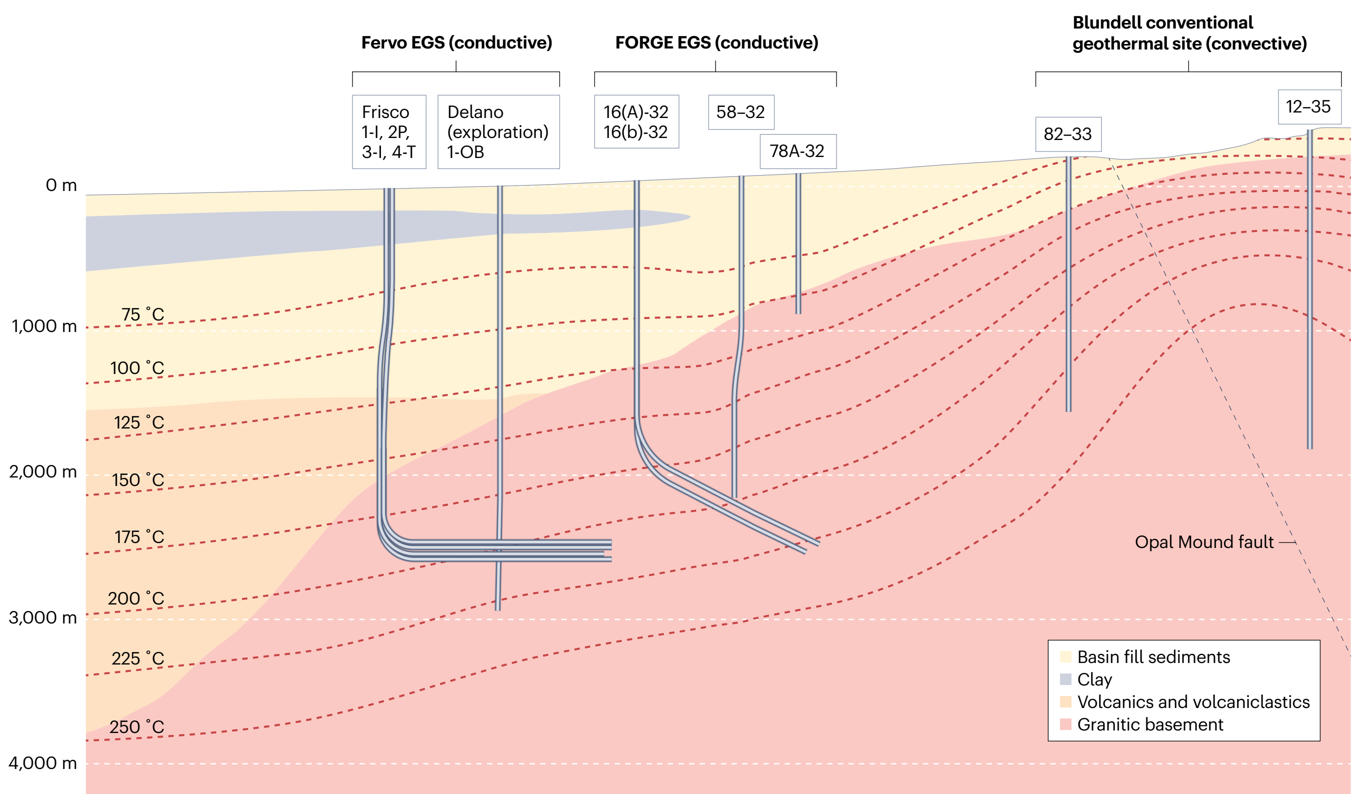

Fig. 2 | Three adjacent geothermal systems. Three geothermal systems are operational in Utah, USA. Two conductive enhanced geothermal systems (EGS) are located within 1 km (Fervo and FORGE). These systems are near (within 2 km) the Blundell conventional geothermal system, which is convective owing to water moving through the naturally occurring Opal Mound Fault. Adapted with permission from ref. 142, Stanford Geothermal Program/Steven Fercho.

shale industry (such as horizontal drilling, multistage stimulation and use of polycrystalline diamond compact (PDC) bits) are being brought into the geothermal industry and have improved drilling performance[33,34]. Previously, conventional geothermal and EGS wells were more commonly drilled with conventional tri-cone roller bits, which wore out faster (requiring more trips to replace the bit) and could not drill as fast owing to limitations on the weight that could be placed on the bit[31]. The newer horizontal drilling and multistage stimulation approaches allow consistent access to a reservoir volume sufficient to sustain an EGS project over the life of the power station[21,32,35] (Fig. 3).

Some EGS drilling designs have borrowed from oil and gas shale practices by drilling multiple wells from a single pad[33]. The multiwell pads can host eight or more wellheads, each spaced ~5 m apart[33]. This approach reduces geological risks by ensuring that the vertical sections of each well encounter similar lithologies. Multiwell pad usage enables fewer rig mobilizations, as modern drilling rigs are able to skid between wellhead locations within hours instead of days[36]. Additionally, by grouping wellheads close together and placing the well pads closer to the power plant facility, it is possible to concentrate surface pipelines and reduce the total length of pipelines required and hence the capital cost of the project[37].

Advancements in drilling technology commonly follow a learning curve, in which the learning rate is the percentage cost reduction for every doubling of total wells drilled. Learning rates of ~18% have been demonstrated in the shale gas industry, suggesting that similar improvements could be achieved in the geothermal sector[38]. As shown in field applications, EGS drilling performance also follows a learning curve, with the opportunity for the application of workflow to remove limiters and overcome dysfunction, leading to cost reductions as the technology scales in the future (Fig. 4). For example, at the Utah FORGE site, two highly deviated geothermal wells were drilled in a granitoid formation using PDC bit technology, achieving rates of penetration of more than 30 m h^{-1} (ref. 39). Fervo Energy has reported[33] drilling results from eight horizontal wells drilled across two different basins in Nevada and Utah, also using PDC bits. There was a 60% reduction in drilling days over this series of eight wells, equating to a 35% learning rate.

Stimulation to create EGS

EGS stimulations occur through the propagation of artificially created fractures and/or opening and shearing of pre-existing fractures that occur naturally in the rock. Stimulation is key to allowing fluid flow in EGS, but can also induce seismicity, which must be managed. This section describes stimulation mechanisms and management and highlights results from early stimulation efforts and from projects in the 2020s.

Stimulation mechanisms and techniques

Hydraulic stimulation is performed with high rate and high pressure injection of fluid (usually water), which can also contain proppant (a particulate material such as sand)[40]. Stimulation occurs through propagation of newly forming fractures and/or shear stimulation of pre-existing fractures. Shear stimulation occurs when fluid injection increases pressure and induces slip, which increases natural fracture conductivity[5,41–46]. Newly forming fractures can initiate from the well or from pre-existing fractures and flaws. Initiation from the wellbore can be a complex process, depending on wellbore orientation with respect to the stress state[47]. Once initiated, fractures can propagate as long as their internal fluid pressure exceeds the magnitude of the minimum principal stress (Shmin), plus a small additional net pressure that is determined by the fracture toughness[40,48]. Even if the fluid pressure is less than the minimum principal stress, fracture slip can create splay or wing cracks, opening mode features that propagate a limited distance from the shearing feature[49,50].

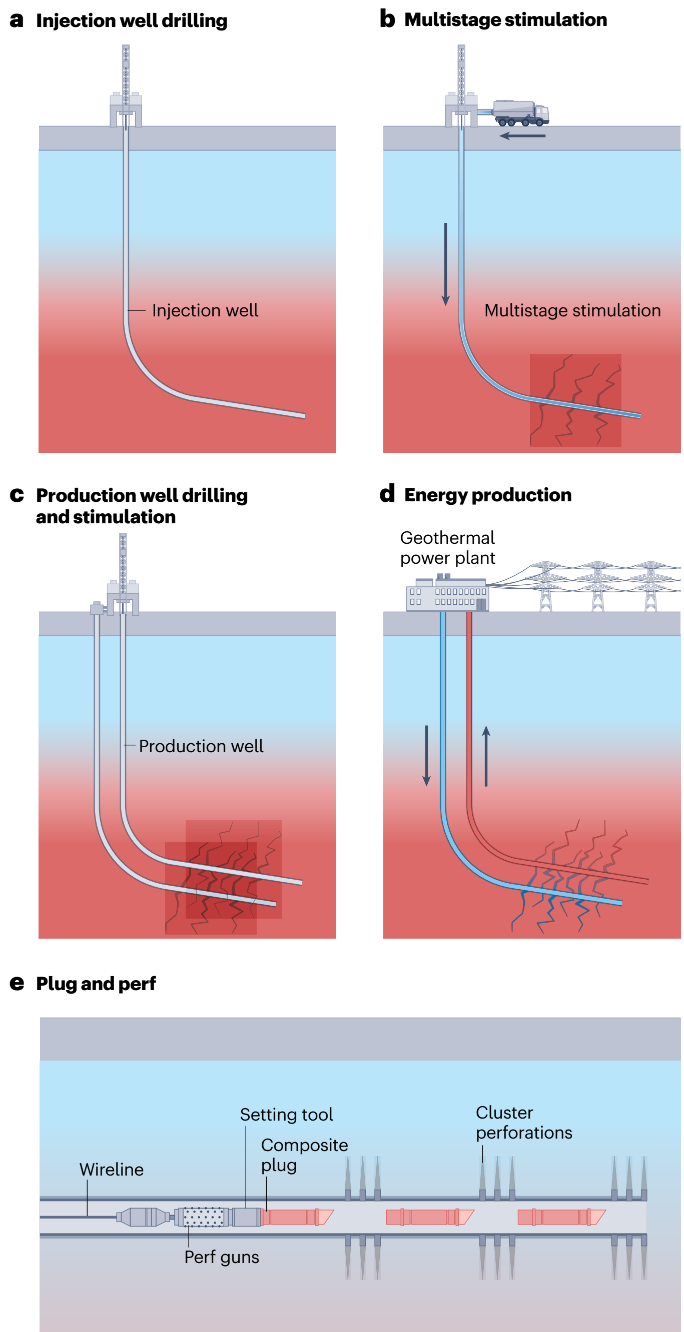

Fig. 3 | Drilling and stimulation for enhanced geothermal systems. **a**, Enhanced geothermal system development begins with drilling of an injection well. **b**, Fractures are created using multistage stimulation. **c**, A production well is then drilled and stimulated. **d**, Energy is produced from the wells. **e**, Plug and perf technology to control stimulation.

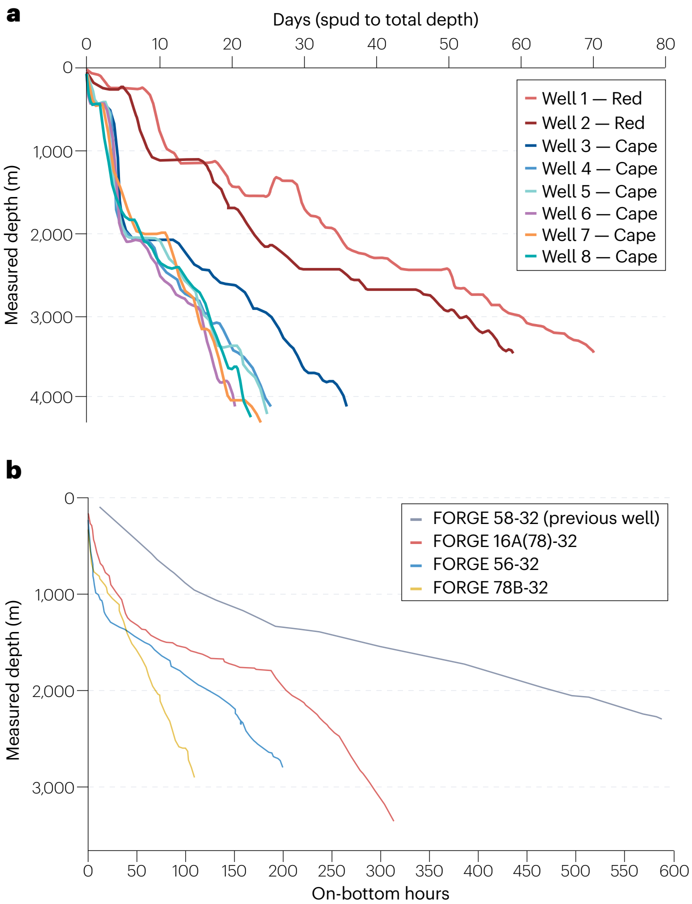

Fig. 4 | Improved drilling performance. **a**, Drill rate at Project Red and Project Cape. **b**, Drill rate at Utah FORGE. Enhanced geothermal systems drilling performance follows a learning curve. Panel **a** adapted with permission from ref. 33, Kareem El-Sadi. Panel **b** adapted with permission from ref. 32, American Rock Mechanics/James Moore.

Splay fractures are associated with fault formation in granite[49,51] and brittle compressive failure of intact rock[52]. However, it is unlikely that EGS stimulation leads to the formation of entirely new shear faults through the brittle compressive failure of intact rock. The compressive strength of rock is high, especially under confining stress and in the crystalline lithologies where EGS is typically performed[53]. Stimulation might advance fault development incrementally through fracture link-up, but overall the development of fault zones in crystalline rock is a complex, progressive process[54,55] that requires a larger magnitude of strain than results from an episode of stress release due to high pressure injection.

Under some conditions, hydraulic fracture propagation can be arrested by interaction with a pre-existing plane of weakness[56,57]. This observation has been formulated into numerical modelling codes that predict volumetric, branching fracture networks[58,59]. However, during practical field-scale fracturing, several factors can limit the effect of termination: cementation that gives natural fractures cohesion[60]; the ability to propagate over and around pre-existing fractures[61]; and the reinitiation of a new hydraulic fracture a short distance after termination[62].

Evidence is mixed on the relative significance of shear stimulation and/or propagation of newly forming fractures, and there is considerable uncertainty and disagreement about the relative role of stimulated natural fractures versus newly forming fractures. For example, compare the differing interpretations from refs. 62,63 on the EGS Collab project or from refs. 64,65 on the Desert Peak EGS project. There is also uncertainty about how these fractures interact, including the frequency that newly propagating fractures terminate against pre-existing fractures, and the frequency with which new fractures initiate from pre-existing fractures[60,62]. From a theoretical perspective, shear stimulation requires that fractures must be well oriented to slip in the stress state; fractures cannot be mineralized shut, or else they will have excessive cohesion and insufficient initial conductivity; fractures must experience a permanent increase in conductivity when they slip; and there must be sufficiently large and well-connected fractures to create percolating flow pathways that extend out into the formation[64]. These conditions cannot be expected to exist at all projects.

Nearly all historic EGS projects have involved injection at fluid pressure greater than the minimum principal stress[66]. Under these conditions, classical rock and fracture mechanics suggest that new fractures should form and propagate through the formation. A small number of projects have intentionally injected at pressure slightly below Shmin, such that shear slip can occur, but fracture opening and/or propagation cannot occur, except as splays in localized regions around shear crack tips[64]. These tests have usually not shown substantial stimulation until injection was subsequently performed above Shmin[27,62,67–70]. However, a number of EGS projects have shown strong evidence of fluid injection-induced slip and stimulation on pre-existing faults. For example, at the Soultz project (France), core and image logs showed the wells crossing large, well-developed faults; spinner logs showed flow localizing to these features; caliper logs showed shear deformation at the wellbore; and microseismic monitoring showed microseismicity localizing to these features[45]. These observations suggest shear stimulation of those existing fracture groups. The Cooper Basin EGS project is another example with strong evidence of stimulated fault zones[19].

A plausible interpretation is that when well-developed, permeable fault zones are already present in the formation, fluid will deviate into them and will likely cause shear stimulation. If these faults have sufficient capacity for flow, they might be able to prevent fluid pressure from reaching Shmin and causing significant hydraulic fracture propagation. However, when fault development is limited, and natural fractures consist only of crack-like joints – and especially if they tend to be mineralized shut – then opening mode fracture propagation may have a dominant role. Practical cases are likely to be intermediate between these two extremes.

Some EGS projects in the USA since 2022 have used plug and perf completion, in which casing pipe is cemented into the wellbores[21,35,71]. Then, fluid is injected into the formation from holes in the pipe called perforations, along with proppant to hold open the fractures after shut-in. This stimulation design targets creation of newly formed fractures, rather than stimulating natural fractures (which can no longer be accessed directly by the well because the steel pipe is cemented into the wellbore). These designs have yielded EGS wells with reported circulation rates up to 100 kg s^{-1} (refs. 21,35,71). The advantage of plug and perf completion with proppant is that it gives engineers more control over the fracturing process. Rather than hoping that natural fractures will have optimal characteristics for effective shear stimulation, engineers create new fractures in an arrangement of their own design.

Perforation clusters are placed and injection schedules are optimized to control the size, spacing and conductivity of the fractures[72]. Achieving a distributed set of fractures, flowing uniformly, is advantageous to the convective heat recovery of a substantial volume of hot rock. However, relative to earlier EGS designs, the main drawback to plug and perf completion is cost. Earlier designs avoided the expense of steel casing and cement in the productive interval, and they did not require proppant, plugs or perforation guns.

The need for proppant in stimulation is not universally accepted throughout the EGS community. In oil and gas well stimulations, the rock types are usually sedimentary and compliant, so newly forming fractures nearly always require proppant to maintain substantial conductivity after shut-in, when the pressure falls below the minimum principal stress and the fracture closes mechanically[73]. However, as some EGS projects have shown[74], fractures in hard crystalline rocks can self-prop owing to the displacement and subsequent mismatch between rock surface rugosities. This reduces or eliminates the potential benefit from placing proppant.

Proppants have been effective in other cases[21,35,71]. For example, at FORGE, three initial stimulation stages were performed without proppant. During a subsequent interwell flow test, the injectivity was observed to be very low. To enable higher rate, injection was performed with bottomhole pressure greater than the minimum principal stress. Nevertheless, the circulation rate into the nearby production well was very low. Next, seven additional stimulation stages were performed with a different design, utilizing proppant. During the subsequent 30-day circulation test, the production rate was around 26 kg s^{-1}, two orders of magnitude greater than it had been during the previous circulation test[59,70,71]. Evidently, the fractures during the initial stimulations did not experience effective self-propping and shear stimulation; the second round of stimulations demonstrated that proppant was more effective in creating sustained flow pathways.

There are other stimulation approaches that are not hydraulic. Chemical stimulation has been used successfully in some EGS projects[75–78]. These approaches could require less fluid injection and so have lower potential for induced seismicity. However, these approaches – on their own – have not yet achieved commercially viable circulation rates in EGS. Alternative fracturing fluids have been proposed, such as CO_2 and/or foam[79], but these concepts have not yet been robustly tested in the field. As a third stimulation approach, thermal stimulation owing to stress reduction during long-term fluid injection will cause fracture reopening and propagation[28,80–82]. The implications for long-term injectivity and the flow distribution in an EGS are complex and not well understood.

EGS projects tend to be located in crystalline basement rock, which deforms in a brittle manner with minimal ductile deformation[5]. Superhot geothermal (above 400 °C) is an exception – at these temperatures, ductile deformation becomes meaningful. Mechanisms of stimulation under these conditions could be substantially different, and this topic remains an area of active research[83].

Stimulation results in EGS projects

Early stimulation trials for conventional geothermal fields led to productivity improvements up to fourfold in the low-temperature Mosfellssveit field in Iceland[84]. These wells, together with stimulated wells from the Seltjarnes area[85,86], contribute today to the heat supply of the city of Reykjavik. The hydraulic stimulations were typically performed with single packers, injection rates of 15–100 kg s^{-1} and wellhead pressures up to 15 MPa (ref. 84).

Hydraulic stimulation of the Upper Rhine Graben in 1993 by injecting water under pressure generated new permeability in zones with abundant hydrothermal alteration minerals, related to cataclastic shear zones. These results suggested that the stimulation was more successful in reactivating previously active permeability pathways identified in the wellbore, compared with zones with no evidence of prior permeability[45]. Because of the occurrence of past and recent hydrothermal circulations in fractured crystalline rocks, an intense argillic alteration takes place. The presence of clay minerals such as illite could decrease the frictional strength of the fractures, as was observed in the Upper Rhine Graben. Indeed, post-stimulation aseismic deformation has been observed in such clay-rich fracture zones[87]. The main positive impact of the aseismic behaviour of clay-rich fault zones is to reduce induced seismic activity and the related concerns to social acceptance.

However, there is a dual behaviour of fault zones in terms of post-stimulation permeability enhancement. Fractures filled with alteration minerals such as illite could preferentially localize the fluid flow during hydraulic stimulation as proposed by[45]. The absence of dilation in such clay-rich fault zones prevents permeability enhancement as reported by[24]. Induced microseismicity activity was recorded during the thermal stimulation of the Rittershoffen injection well[75], which resulted in an improvement of the injectivity index by a factor of two.

Reservoir conductivity at Utah FORGE has been enhanced by two high-pressure hydraulic stimulations (multistage stimulation) of the granitoid rock mass[88], opening new hydraulic fractures and/or activating pre-existing natural fractures. The FORGE project used multistage stimulation along a highly deviated lateral and experimented with two different stimulation strategies[88]. The first set of stimulations, in July 2023, were performed along three stages at the toe of the well and did not use proppant. An interwell circulation test achieved a low circulation rate, 0.44 kg s^{-1} (ref. 59). The second set of stimulations, from March to April 2024, was performed with proppant in six new stages. In addition, a previous stage was restimulated and the production well was also stimulated. A subsequent 10 h circulation test achieved a production rate of 22 kg s^{-1} from an injection rate of 35 kg s^{-1}, with the production rate still increasing steadily when the test was ended[71]. The stimulated lateral length was around 300 m (ref. 70).

In 2023, production testing of a horizontal well EGS was completed at Project Red in northern Nevada, USA, using the plug and perf stimulation approach and proppant[21]. The Project Red system (adjacent to the Blue Mountain conventional geothermal field) was commissioned in the summer of 2023 and began supplying power to the grid by October. The reported well-to-well flow rate was 63 kg s^{-1} (ref. 21). At Project Cape in southern Utah, by September 2024, 15 horizontal wells had been drilled. A three-well pad was stimulated by the plug and perf approach, with 80 treatment stages, all with proppant. During a 30-day test, the first production well reached a peak flow output equivalent to 12 MW electrical generation capacity and sustained 8–10 MW. The maximum well-to-well flow rate was 121 kg s^{-1}, stabilizing at 93 kg s^{-1} (ref. 35).

EGS-induced seismicity

EGS can cause earthquakes during stimulation and operation. Although most are usually small and only detectable on sensitive instruments, some are large enough to create nuisance shaking and a few have been strong enough to cause structural damage and human injury, leading to the delay, scaling back or cancellation of the industrial activity[89].

Seismicity occurs when fluids are either injected into or extracted from faults, which can tip the balance between applied stress and fault strength[90]. In many settings, such a fault is brought to failure by transmission of increased pore pressure to the fault, reducing the effective normal stress ($\sigma_n - P$). Earthquakes can also be initiated through poroelastic effects that increase the driving stress τ and/or reduce the effective normal stress ($\sigma_n - P$) destabilizing the fault. New faults can also be created during hydraulic fracturing operations in which the high pressures needed to create tensile fractures can also nucleate and propagate shear fractures[91].

For both natural and engineered geothermal energy projects, long-term circulation of fluids has the potential to destabilize faults through contractional strains caused by cooling of the rock mass or disturbance of geochemical equilibrium of faults and fractures from fluid–rock interactions, thereby weakening faults by reducing the coefficient of friction μ or the cohesion S_0 (refs. 92–94). Within geothermal reservoirs, seismicity could be beneficial as it can help maintain the permeability of the system as the reservoir rock contracts and opens fractures that could otherwise close or restrict flow paths[95].

However, seismicity of undesirable magnitude induced during stimulation can negatively impact the goal of stimulation when one or a few faults release most of the input hydraulic energy. As they slip, they develop narrow, highly permeable zones along the fault surface with little or no improvement to volumetric bulk permeability[96]. High-resolution images of stimulation seismicity at Habanero in Australia and Soultz-sous-Forêts in France indicate that kilometre-scale faults were activated during stimulation[97–99]. In operation, fluid from the injector will be channelled through the fault, extracting heat from a very limited volume of surrounding rock, thereby severely limiting the thermal output of the project.

There are a few commercial and operational EGS sites worldwide that have published long-term circulation data sets in terms of induced seismicity monitoring and hydraulic parameters (flow rate, surface temperature and reinjection pressure), including the Upper Rhine Graben. During geothermal plant operation in this region, induced seismicity has been observed at depths generally in the vicinity of the reinjection well where colder temperatures are found. After delivering its thermal energy to the surface infrastructure, the geothermal fluid becomes cooler and thus denser inducing thermomechanical effects on the rock mass in the vicinity of the reinjection well[75]. This could be why induced seismic activity was observed near the reinjection wells at both Soultz and Rittershoffen.

From the operational point of view, the link with hydraulic parameters (flow rate, well-head pressure and reinjection temperature) is not straightforward[100]. The majority of the seismic events are located within the first kilometre of the open-hole section of the injection well. At Rittershoffen, from 2016 to mid-2024, about 8,000 microseismic events were induced during the geothermal exploitation[100]. However, in May and July 2024, Rittershoffen experienced three seismic events with local magnitudes of 2.0 and 2.2 that occurred under normal operational conditions. The mechanism of the events has not yet been determined. Apart from these three minor occurrences, this demonstrated that this site has been exploited safely with nearly no negative impact on the local population over the past 8 years. This lesson is important because the perception of geothermal energy became controversial in the community owing to the seismicity observed in the Strasbourg urban area (France) between 2019 and 2021 (ref. 101).

Managing EGS-induced seismicity

Induced earthquakes have been particularly problematic for attempts to develop EGS in Switzerland, the Republic of Korea and France[102]. For example, in Strasbourg, about 10 induced or triggered earthquakes up to magnitude ML3.9 were felt and resulted in minor damage. As a result, the nearby Geoven EGS project was cancelled[101]. Consequently, developing plans to mitigate the risk posed by induced earthquakes needs to be an integral part of EGS developments during both the construction and operational phases of the project.

Managing unwanted seismicity during hydraulic fracturing operations remains an ongoing challenge, as there is no simple formula or action that is guaranteed to avoid the occurrence of a serious event once seismicity has been initiated[103]. Induced earthquakes appear to follow the same statistical laws governing their magnitudes as natural earthquakes: the more the events, the greater the chance of larger events occurring[104]. Although it has been suggested that the upper magnitude could be limited by factors including the total volume of injected fluid or the duration of operations[102], earthquakes exceeding those bounds do occur and are often the most damaging to both the project and the society[89].

When combined with the exposure of people or the built environment and their vulnerability, the resulting risk or chance of suffering loss or harm from induced seismicity can be quantified. This risk — to the project, nearby populations and infrastructure — needs to be considered when developing mitigation strategies for induced seismicity[105,106]. A serious risk to the project itself is loss of the licence to operate, some cases of which have resulted from earthquake shaking levels well below the structural damage threshold[107]. Nuisance shaking from earthquakes no larger than M3–4 has led to the cancellation of EGS, unconventional hydrocarbon and natural gas production and storage projects worldwide[89,102].

Experiences with hydraulic fracturing have shown the benefits of well-planned operational controls for addressing seismicity[89,91,108–110]. In practice, these controls often take the form of a traffic light protocol that is informed by high-sensitivity local seismic monitoring and that defines actions to be taken at the well site if certain earthquake magnitudes are exceeded. The protocol is commonly set as green for normal operations, yellow to trigger a defined response and red to stop operations, either temporarily or permanently[105]. Such traffic light systems are most successful when they have been developed with input from all stakeholders, including the public, and operate in a transparent and open environment[111,112]. Critical elements of a comprehensive seismicity mitigation plan begin with preliminary site screening, development of hazard models for both natural and induced events, evaluation of the risk posed by induced events to people and property and ongoing public ongoing communication with all findings, among other steps[108].

In an analysis of approaches to mitigate induced seismicity at the Haute-Sorne EGS project in Switzerland, it was proposed[113] that the multistage stimulation approach, such as that used at FORGE, would reduce the risk of triggering seismicity compared with a single massive stimulation as used in earlier EGS projects.

The long-term effects of heat extraction and geochemical interactions during EGS operation are poorly understood. However, loss of injected fluid to the formation has the potential to induce earthquakes, just as wastewater disposal does for unconventional oil and gas production[109]. Preparing for these and other scenarios will require a different approach than used during the development phase, but like development will be best served by systematic and transparent monitoring of seismicity to a very low level of magnitude completeness[89].

EGS applications and energy generation

The intended use of EGS and the valuation of resources have changed over time. EGS is currently used for electricity generation, direct heat supply or a combination of both. Depending on the production temperature, the conversion of heat into electricity can precede the heat supply. Additionally, a seasonal fluctuation in demand can lead to a seasonal change in use. This section describes the use of EGS for electricity, heat supply and other resources.

Electricity

EGS can provide steady baseload power, which is useful in energy systems with large amounts of intermittent energy sources. Geothermal heat from EGS is converted into electricity using either a steam turbine or an organic Rankine binary cycle with conversion factors of around 12%[114,115].

On the basis of early attempts to develop EGS technology by Los Alamos Scientific Laboratory at the Fenton Hill site, energy content of heat in place was estimated as 13×10^{24} J for the entire USA. This estimate considered the energy stored as heat between 50 °C and 150 °C in the crustal rock at depth less than 10 km (ref. 116). At the time (1979), only about 0.2% was estimated to be recoverable and convertible to electric energy at a factor of 0.08–0.2 using binary cycle power plants[117]. Following the learning curve on convective EGS, the technical potential in Europe for temperatures greater than 150 °C and depths of 3–10 km was estimated to be greater than 6,500 GWe. The part of this technical potential that can be considered as 'sustainable' potential was estimated to be 35 GWe. In the USA, the growth is expected to reach more than 45 GWe by 2050 (ref. 118), and most of this growth is anticipated to come from the development of conductive EGS resources after 2030.

At Altheim (Austria), chemical treatments in sedimentary rock expanded the previous heat supply to a heat (14.4 MWth) and power supply of 1 MWe in 2001 and were also used to enhance the output at Unterhaching (Germany) where power generation with an installed capacity of 3.4 MWe began operation in 2004 (ref. 119). The first commercial EGS power plant that is connected to a fractured reservoir in the crystalline basement rock (convective system) was commissioned in 2007 in Soultz-sous-Forêts (France) and still operates at an installed capacity of 1.7 MWe (ref. 74). In the 2000s, at Landau (Germany), the EGS involved a combination of sedimentary and crystalline rocks and the installed capacity of the plant was enhanced to 3 MWe in 2007, and nearby at Insheim (Germany) to 4.8 MWe in 2012.

Currently, in the USA, electricity from EGS is mostly associated with projects in or near conventional geothermal fields and in the crystalline basement. For example, at Project Red near the Blue Mountain field (Nevada, USA), flow rates of up to 63 kg s^{-1} at a water temperature of 169 °C were reported from a naturally conductive system, corresponding to a peak electrical output of 3.5 MWe (refs. 21,35). A superhot EGS is being developed at the Newberry site in Oregon[120].

Projects in other regions are in development. For example, the Qiabuqia EGS project, Tibetan Plateau, China[121] was thermal-hydraulically stimulated in 2018 and is expected to contribute 4–4.7 MWe of electrical power. Power generation from superhot and supercritical EGS is targeted in different countries. After the IDDP-1 and IDDP-2 EGS wells in the Krafla and Reykjanes geothermal fields in Iceland, the IDDP-3 targets superhot fluids in the Hengill field[122].

Direct heat

EGS can be used for urban district heating or production of process heat for industrial facilities. In Germany, Austria and France, successful EGS prototypes initially targeted electricity provision[123–125]. In Europe, the modest conversion efficiency of binary power plants and the need for climate neutrality in all energy sectors have led to a focus on direct heat supply from EGS. In Altheim (Austria), direct use has been given priority over electricity generation. Electricity conversion in Unterhaching (Germany) was discontinued in 2017 in favour of direct heat use. Both plants are produced from chemically stimulated sedimentary rocks and supply a heat output of greater than 40 MWth (ref. 126). There are limits to this development. The Australian demonstration project in the Cooper Basin (Australia) with an installed electrical capacity of 1 MWe investigated how process heat could be provided as it is far away from the electricity grid. In the absence of a heat off-taker, the project did not proceed to the next phase of demonstrating this application.

The direct utilization of low-temperature geothermal resources, in general, enables new resource assessment. For example, by 2045, an estimated 25% of Germany's heat demand can be met by low-temperature systems connected to areas with generally favourable geothermal conditions[127] and usually requiring only chemical stimulation. A large part of this development was outlined in Stadtwerke München's District Heating Vision 2040 from 2012. The aim of this vision is to supply the ~800 km long heating network in Munich with completely CO_2-neutral heat by 2040 (ref. 128). Moreover, a further 20–30% is expected to be covered by EGS with hydraulic and chemical stimulation[127].

There are also prototypes for the development of direct geothermal energy utilization in the South German Molasse Basin. This basin has low-temperature geothermal resources (36.5 °C in Straubing, Germany, up to 157 °C in Holzkirchen, Germany) from hybrid hydrothermal–EGS wells[9]. The production volumes in this area range from 32 kg s^{-1} in Straubing to 174 kg s^{-1} in Traunreut (Germany). Today, a total thermal capacity of 380 MWth is delivered from around 25 sites[129].

In the Upper Rhine Graben, around 30 MWth of thermal capacity of EGS is available for district heating (5 MWth in Landau, Germany) and industrial heat (24 MWth in Rittershoffen, France)[13]. At Rittershoffen, the injectivity was improved by a factor of five to deliver 25% of the heat demand (at 160 °C) through a 15 km long pipeline to the starch factory at Roquette[13]. Indeed, of the commercial EGS projects in or involving granitic reservoir rock in the Upper Rhine Graben, only two (Soultz-sous-Forêts, France and Insheim, Germany) supply only electricity, as the surrounding municipalities do not have district heating networks.

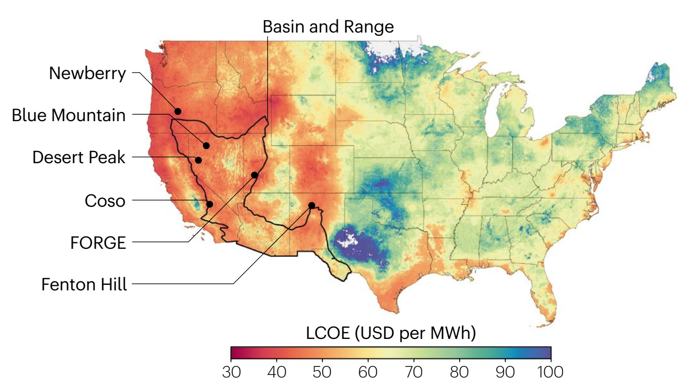

Fig. 5 | Levelized cost of electricity estimated for enhanced geothermal system developments across the continental USA. Estimates of the levelized cost of electricity (LCOE) for enhanced geothermal systems based on 2024 drilling costs and at optimal depth. Location of some of the enhanced geothermal systems discussed in this article are labelled. Regions that are in yellow to red colours have projected LCOE at or cheaper than the average national cost of electricity. Adapted from ref. 136, CC BY-NC-ND 4.0.

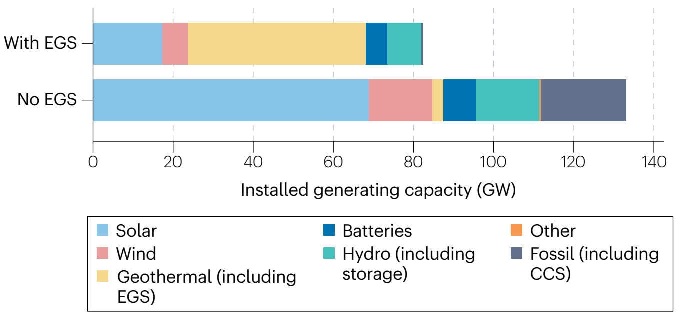

Fig. 6 | Resource capacity examples with and without enhanced geothermal system. Comparison of modelled total installed resource capacity in California in 2045 for enhanced geothermal system (EGS) with 2024 drilling costs and flexible dispatch strategies (with EGS bar) versus without EGS (no EGS bar). CCS, carbon capture and sequestration. Adapted from ref. 141, CC BY 4.0.

EGS projects for direct heat have also been developed in other locations. At the EDEN site in the UK, one such EGS well has been equipped for district heating and nursery applications, producing 85 °C hot water with a coaxial single-well system[18,130].

Lithium extraction

Another application of EGS is in mineral extraction. There is particular interest in lithium extraction in convective EGS, as some of these brines contain lithium, with 168 mg l^{-1} reported in Insheim[131] to 274 mg l^{-1} in the United Downs project[130]. First pilot plants are now being built in the Upper Rhine valley[132]. For example, at the power plant in Insheim, lithium was extracted at operating pressure and temperature by using aluminium hydroxide with pretreatment to remove competing ions[133]. In a pilot project at the Rittershoffen geothermal power plant, sorbent-based lithium extraction was adapted to the temperature and water chemistry of the system. In the Upper Rhine Valley, where the flow rates are between 60 kg s^{-1} and 80 kg s^{-1}, up to 1,000–1,500 tonnes of lithium carbonate equivalent per year can be expected from the plants operating for both heat and lithium extraction (depending on the efficiency of the extraction[132,134]). On the basis of the current state of extraction technology and geothermal energy production in the Upper Rhine Graben, a maximum production of 7,200 tonnes per year of lithium carbonate equivalent is expected.

Economic considerations

In 2023, the IEA suggested that EGS will become economically viable after 2030, assuming a global-installed capacity of 100 GWe of electricity from EGS by 2050 (ref. 4). This prediction suggested that EGS could be used wherever there is a demand for electricity and heat, using mainly binary power generation technology and independent of existing conventional geothermal reservoirs. EGS can also support substantial growth in the non-electric sector for district heating and other direct use applications. For example, compared with the current installed thermal capacity of 100 MWth (ref. 135), the GeoVision report suggests a possible increase in geothermal heating systems in the USA to 315 GWth in 2030 from the systematic expansion of EGS for heating purposes[118].

Technological advances have changed the economic outlook for EGS considerably. The US Department of Energy Pathways to Commercial Liftoff Report[10] investigated the decreases in capital cost and levelized cost of electricity (LCOE) in EGS projects, based on the 2023–2024 observed field experiences and expected future reductions. The report suggests that EGS is on track to achieve costs of energy competitive with other clean, firm power sources in the near term. For example, EGS is expected to be competitive in terms of the capital costs of plants (US$4,500 per kW) and LCOE (US$60–70 per MWh) by 2030. Similarly, an estimate of the likely values of the LCOE across the continental USA concluded that EGS electrical power could be generated at a cost of US$80 USD per MWh or less in most regions[136] (yellow to red regions of Fig. 5). Those estimates suggest that EGS is competitive with the national average generation cost of US$80 per MWh quoted by the Energy Information Agency. Cost-effectiveness could be also expected in many other countries, based on a broader worldwide study at a coarser scale[137], as well as the global analysis of the International Energy Agency[138].

An important economic consideration in EGS deployment is the role it has in providing a clean, firm power source in an electrical grid that also depends on large contributions of intermittent generation such as from wind and solar. Making geothermal generation (both conventional and EGS) flexible and dispatchable could provide additional grid stability and the reduction in the overall 'nameplate' capacity required for intermittent sources[139]. There are already conventional geothermal power plants that operate in dispatchable mode, such as the one on the island of Hawaii[140]. Owing to the greater degree of control possible over EGS injector–producer well pairs compared with conventional systems, it is expected that EGS will be able to flexibly dispatch electricity[139].

Another economic consideration is how EGS fits into an energy system with a broad portfolio of power sources, such as hydroelectric, wind, solar, nuclear and thermal. The different costs of electricity, the different degrees of variability and the different capital costs make the optimization of a nationwide or regionwide distribution network complex. For example, the impact of EGS on a possible future net-zero energy grid was examined with a gas-electric capacity expansion model of the California statewide energy network[141] (Fig. 6). Without EGS, the total grid capacity would need to be much larger to accommodate the intermittent sources, and grid-connected battery storage would also need to be higher. Flexible dispatch of EGS would allow for greater deployment of solar photovoltaics, although the total 'nameplate' capacities need to be bigger. Improvements of drilling rates in 2023–2024 enable greater penetration of EGS and a smaller requirement for total installed capacity overall.

Conclusions

There have been many EGS projects since the introduction of the idea in the early 1970s, but there has been increased interest in EGS from developers and policymakers in the past decade, owing to the transition to renewable energy production. As a result, the number and size of EGS projects are increasing, accompanied by scientific and technological innovation. Advances in drilling, in particular, are expected to lower the cost and increase the repeatability of the development of EGS wells and thereby the scalability of EGS projects. The risks of induced seismicity require continued attention and study, but it is evident from multiple projects that the occurrence of felt seismic events can be considered in predevelopment hazard analyses, monitored and accommodated. The advances described in this Review do not imply that EGS technology would enable geothermal anywhere, but do suggest geothermal in many more places.

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Author contributions

The authors contributed equally to all aspects of the article.

Competing interests

J.N. and A.G. work for companies that are involved in the commercial development of EGS projects (Fervo and Electricité de Strasbourg, respectively). M.M. works for a company that markets software for fracture modelling to EGS development companies, including FORGE and Fervo. R.H. serves on the scientific advisory boards of both FORGE and Fervo. E.S. and W.E. declare no competing interests.

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