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Nexus
Review

The role of geothermal plants in the global energy and materials transition

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https://doi.org/10.1016/j.ynexs.2025.100099

BROADER CONTEXT

Although deep geothermal energy currently plays only a relatively minor role, this review shows it could become a major contributor to future global energy and material system transformation. At the same time, the review highlights how current modeling approaches often oversimplify the technical and economic realities of geothermal systems, particularly exploration risks and nonlinear drilling costs. By synthesizing improved modeling practices and emphasizing geothermal's load-following flexibility, the review underscores how these plants can serve as dispatchable assets in renewable-dominated grids. A key contribution is linking geothermal energy to both energy and materials, showing its unique potential to deliver low-carbon power and heat while also opening new opportunities for sustainable raw material production.

ABSTRACT

Although geothermal technology and global capacity for power and heat are advancing, its role in the transition to sustainable energy systems remains notably underexplored. This review finds that many existing energy system models rely on simplified techniques that fail to adequately address the complexities of exploration uncertainties and nonlinear drilling costs. Current linear approaches tend to over- and underestimate drilling costs at lower (+420% at 1 km) and higher depths (–50% at 10 km), respectively. In addition, important factors such as life cycle environmental and social impacts are often overlooked. We synthesize key data sources and identify best modeling practices for geothermal plants, examining fixed versus variable drilling depths, as well as detailed cost functions. Crucially, we position geothermal energy within the broader energy-material nexus, emphasizing how geothermal systems can contribute not only to decarbonization but also to reducing pressure on critical raw material supply chains. Further innovations such as the flexibility of geothermal plants in load-following operation, and the potential for technological learning through policy support are identified as key game changers that could enhance the role of geothermal energy in future systems.

INTRODUCTION

Globally, sedimentary aquifers and enhanced geothermal systems (EGSs) offer significant untapped potential for harnessing geothermal heat.[1,2] Compared to the large global potential of deep geothermal energy, the developed capacity of the technology is still rather low. Although geothermal power capacity has grown 7.7-fold since 2010, only 16.3 GW_e were installed across 32 countries by 2023 (see Figure 1A). The United States has the largest installed capacity with 3.9 GW_e, followed by Indonesia (2.4 GW_e) and the Philippines (2.0 GW_e). Around 53% of this installed capacity is of the flash type, followed by 25% of binary organic Rankine cycle units and 18% of the dry steam type, with only a few plants based on EGSs.[4] Today, this translates into only 0.34% of worldwide electricity production.[4] However, because of a high potential capacity factor, geological availability, and the potential for on-site material extraction, geothermal plants in general and EGS-based plants in particular may play a larger role in heat and electricity production in the future. At this point it is important to clarify that EGS primarily refers to a reservoir engineering approach to access geothermal heat in low-permeability formations. This article uses the term "EGS-based plant" to describe power plants that utilize EGS technology for subsurface heat extraction, even if the surface power generation systems (e.g., binary cycle, flash steam) are not unique to EGSs.

Given the great global potential for deep geothermal energy plants, this technology is widely anticipated to play a pivotal role in the future energy transition. Furthermore, in light of recent advancements in on-site material extraction, it is poised to contribute to the material transition as well. To gain a better understanding of this future role, it is crucial to evaluate the technology's potential through energy system and integrated assessment studies. To this end, the complex geothermal plant technology must be accurately represented in the system models, and all possible techno-economic, environmental, and social impacts must be considered. Previous reviews have extensively examined various aspects of deep geothermal energy, including technical overviews of exergetic assessments,[6] power plant technology,[7] models for thermo-fluid dynamic phenomena,[8] and

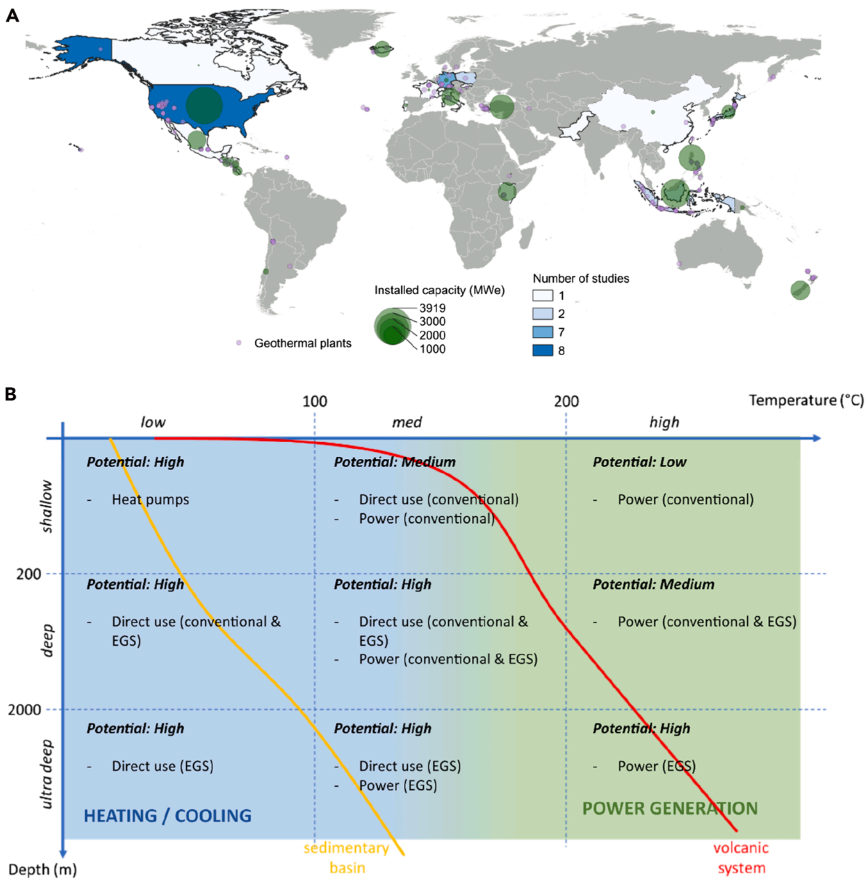

Figure 1. Global geothermal installations and the technologies used for different temperature-depth combinations

(A) Worldwide geothermal power plant locations,[3] installed capacity per country in 2023,[4] as well as the number of reviewed articles that include deep geothermal plants in energy system analyses for the respective country.

(B) Temperature-depth combinations and suitable geothermal technologies. The figure is adapted from van der Zwaan et al.[5] The potential in the various quadrants represent qualitative indications, and real potentials are both technology and location specific. The terms "conventional" and "EGS" in brackets refer to the technology for subsurface heat extraction.

geomechanical rock performance.[9] Other reviews have focused on resource assessments,[10] coupling with CO_2 storage,[11] heat recovery applications,[12] and specific resource utilization, such as through EGSs.[13] In addition, reviews have examined environmental and material impacts, such as environmental hotspots,[14] life cycle assessments of geothermal power generation[15] and EGSs,[16] chemicals used in stimulation processes,[17] and potential for critical material extraction.[18] However, the modeling of deep geothermal plants within energy system optimization or integrated assessment frameworks remains largely unexplored.

This review addresses this gap for the first time by examining how deep geothermal plants are represented in system models, with a particular focus on techno-economic aspects, such as drilling depth and associated costs, and their implications for the technology's economic potential. We define "deep geothermal" according to Figure 1B and include all geothermal plant technologies analyzed in energy system models, except shallow systems such as heat pumps. The role of geothermal plants in these models is shaped by their technical potential, influenced by geological resources, power cycles employed, and potential innovative value creation, such as raw material extraction. We show that deep geothermal plants are typically depicted in a simplified manner in most energy system analyses, without accounting for their complex technical and economic characteristics. As this lack of detail can lead to inaccuracies in evaluating their viability and role in the energy transition, we discuss approaches for addressing these research gaps. We discuss many other identified research gaps and how future system analyses could incorporate technological innovations such as flexible operation or material extraction, uncertainties such as variations in geological conditions, drilling success rates, and cost projections, as well as environmental and social impacts. Finally, we evaluate the implications of these findings for the potential future role of geothermal energy in global energy transitions, emphasizing how improved modeling practices can better integrate geothermal energy into sustainable energy systems.

RESULTS

This section presents the state-of-the-art in modeling deep geothermal systems in energy system analyses. In the vast majority of reviewed studies, geothermal plants are designed within energy system optimizations to minimize costs with a central planner perspective. Geothermal plants are primarily analyzed in countries where the technology is already being developed in reality (see Figure 1A), such as the United States (eight articles[19–26]), Germany (seven articles[27–33]), or Indonesia (two articles[34,35]). In addition, there is only one study each with a global[5] and European[36] scope. Kenya, the country with the largest geothermal power capacity under construction,[37] is also examined in the reviewed articles.[38] In the following, we focus on the modeling of the geothermal plants instead of providing further general information on the studies.

Resource utilization, commodities, and power cycles

There has been extensive discussion in the literature regarding the classification of geothermal systems.[39] Based on Moeck,[40] we primarily distinguish between conventional hydrothermal systems (excluding EGSs) and petrothermal EGS systems, with CO_2 plume geothermal (CPG) considered a special case. Most energy system studies consider only 1 geothermal resource utilization approach: 18 articles investigate conventional hydrothermal systems, 11 EGSs, and 2 CPG (see Table 1). While in conventional hydrothermal systems, which are naturally permeable, the water in the aquifers can be used directly (i.e., with minimal reservoir engineering), in EGS systems, their low permeability must be enhanced through different stimulation techniques, such as hydraulic, thermal, and chemical stimulation. The hydraulic stimulation operations are the most common ones: high-pressure cold water is injected into a deep rock formation via injection wells with the objective of increasing permeability by creating new fractures and causing pre-existing fractures to re-open. The hot water is then returned to the surface via production wells, where the heat from the water is used in district heating networks or converted into electricity using a steam turbine or a binary power plant. The cooled water is reinjected into the ground again in order to complete the closed-loop process.[1,2] CPG uses CO_2 as working fluid in natural high-permeability sedimentary basins with high CO_2 storage capacity. In contrast to EGSs, this eliminates the need to create high-permeable regions with fracturing.[41] Only three studies[5,26,36] consider both hydrothermal systems and EGSs and one study hydrothermal systems and CPG.[22]

In most articles (53%), the geothermal heat can be used to supply electricity and heat, in 36% of cases only to supply electricity and in 8% of cases only to supply heat. Since mainly low-temperature geothermal sources or high-temperature resources close to 150°C[42] are considered, binary power plants are primarily modeled for the

Table 1. Classification of reviewed studies on modeling of geothermal plants

Study	Resource-utilization	Temperature	Drilling depth	Geothermal commodities	Power cycle	Investment decision
Onodera et al. 2024	N/A	N/A	N/A	Power supply	N/A	Cost-competitive
Oyewo et al. 2024	EGS	N/A	Fixed depth	Power supply, Heat supply	Binary	
Ricks et al. 2024	EGS	High temperature	Variable depth	Power supply	ORC	Cost-competitive
Kleinebrahm et al. 2023	Conventional	High temperature	Variable depth	Power supply, Heat supply	ORC	Cost-competitive
Wang et al. 2023	N/A	N/A	Fixed depth	Power supply, Heat supply	N/A	No investment decision
Weinand et al. 2023	Conventional	Low temperature, High temperature	Variable depth	Power supply, Heat supply, Lithium extraction	ORC	Cost-competitive
Yudiartono et al. 2023	N/A	N/A	N/A	N/A	N/A	Cost-competitive
Molar-Cruz et al. 2022	Conventional	Low temperature, High temperature	Variable depth	Heat supply		No investment decision
Ordonez et al. 2022	N/A	N/A	N/A	Power supply	N/A	Cost-competitive
Tian et al. 2022	EGS	N/A	N/A	Power supply, Heat supply	N/A	N/A
Van Brummen et al. 2022	CO_2-Plume	Low temperature	Fixed depth	Power supply	CO_2	Cost-competitive
Weinand et al. 2022	Conventional	Low temperature, High temperature	Variable depth	Power supply, Heat supply	ORC	Cost-competitive
Gerbelová et al. 2021	Conventional	N/A	N/A	Power supply	Flash	Not cost-competitive
Miranda et al. 2021	EGS	Low temperature, High temperature	Fixed depth	Power supply, Heat supply	N/A	No investment decision
Ogland-Hand et al. 2021	Conventional, CO_2-Plume	Low temperature	Fixed depth	Power supply	CO_2 & ORC	No investment decision
Spittler et al. 2021	Conventional	N/A	Fixed depth	Power supply	N/A	Cost-competitive
Temiz & Dincer 2021a	Conventional	High temperature	Fixed depth	Heat supply		No investment decision
Temiz & Dincer 2021b	Conventional	High temperature	Fixed depth	Power supply, Heat supply	ORC	No investment decision
Weinand et al. 2021	Conventional	Low temperature, High temperature	Variable depth	Power supply, Heat supply	ORC	Cost-competitive
Yin et al. 2021	N/A	Low temperature	Fixed depth	Power supply, Heat supply	ORC	No investment decision
Barbaro & Castro 2020	N/A	N/A	N/A	Power supply	N/A	Cost-competitive
Dalla Longa et al. 2020	Conventional, EGS	N/A	Variable depth	Power supply, Heat supply	Binary & flash	Cost-competitive
Gladysz et al. 2020a	EGS	High temperature	Fixed depth	Power supply, Heat supply	Brayton	No investment decision
Gładysz et al. 2020b	EGS	High temperature	Fixed depth	Power supply, Heat supply	Brayton	No investment decision
Spittler et al. 2020	Conventional	N/A	Fixed depth	Power supply	N/A	Cost-competitive
Andrés-Martínez et al. 2019	N/A	N/A	N/A	Power supply	N/A	Cost-competitive
Kazmi & Sheikh 2019	Conventional	Low temperature	Fixed depth	Power supply	Binary	No investment decision
Tian & You 2019	EGS	Low temperature	Fixed depth	Power supply, Heat supply	ORC	No investment decision
Van der Zwaan et al. 2019	Conventional, EGS	Low temperature, High temperature	Variable depth	Power supply, Heat supply	Binary & flash	Cost-competitive
Weinand et al. 2019a	Conventional	Low temperature, High temperature	N/A	Heat supply		No investment decision
Weinand et al. 2019b	Conventional	Low temperature, High temperature	Variable depth	Power supply, Heat supply	ORC	Cost-competitive
Barbato et al. 2018	N/A	Low temperature	Fixed depth	Power supply, Heat supply	ORC	No investment decision
Marty et al. 2018	Conventional	High temperature	Fixed depth	Power supply, Heat supply	ORC	No investment decision
Ou et al. 2018	N/A	N/A	N/A	Power supply	N/A	Cost-competitive
Moret et al. 2016	EGS	Low temperature, High temperature	Fixed depth	Power supply, Heat supply	ORC & Kalina	Cost-competitive
Jacobson et al. 2015	Conventional, EGS	N/A	N/A	Power supply	N/A	No investment decision

Conventional · EGS · CO_2-Plume · Low temperature (≤ 150 °C) · High temperature (> 150 °C)
Fixed depth · Variable depth · Power supply · Heat supply · Li Lithium extraction
No investment decision · Not cost-competitive · Cost-competitive

Geothermal resource utilization approaches include conventional hydrothermal, enhanced geothermal, or closed-loop (here: CO_2 plume) geothermal. The temperature range is distinguished between low-temperature and high-temperature geothermal heat (cf. Figure 1B). The drilling depth is either fixed in the reviewed studies, or variable and therefore the result of optimization calculations. Electricity, heat, and material supply are considered for the commodities. When considering the supply of electricity, the geothermal heat is converted into electricity in different power cycles. In addition, not all studies consider geothermal systems in competition with other technologies and, when they are, it is shown whether they are competitive.

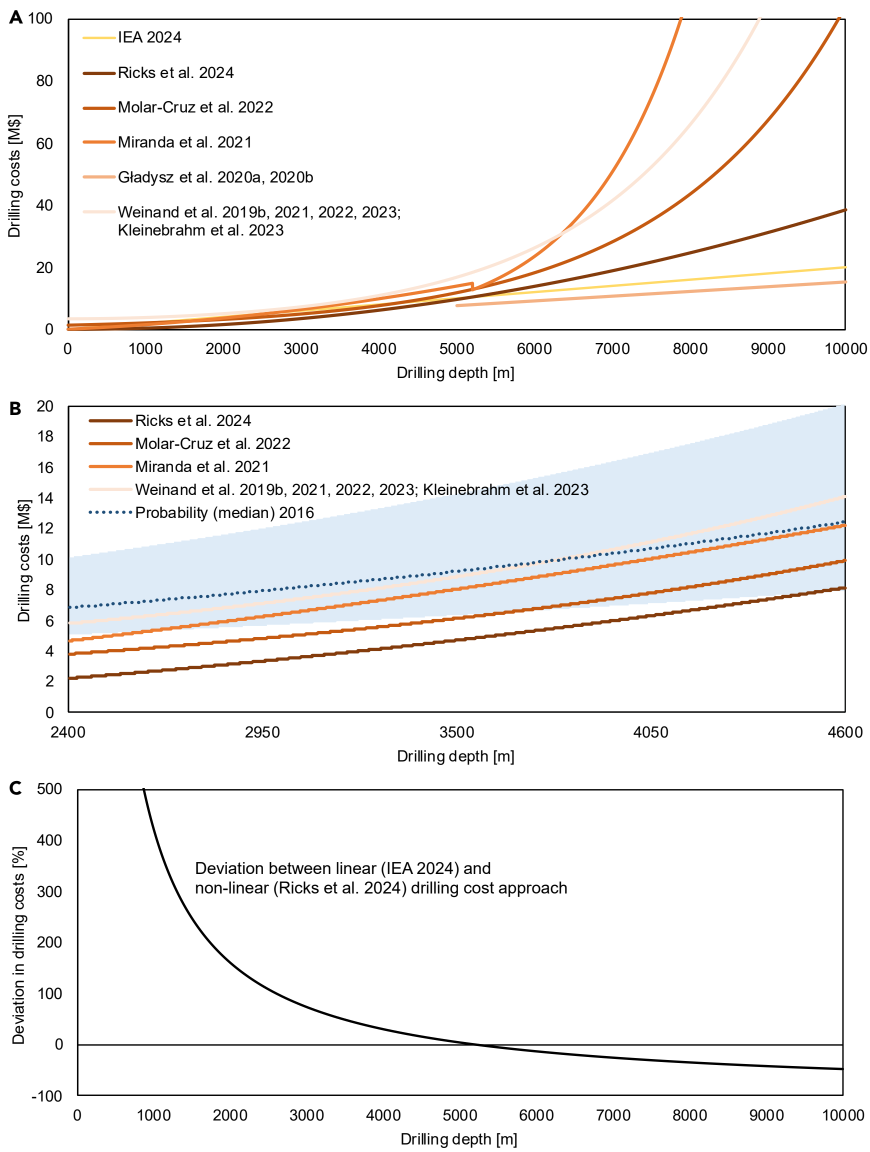

Figure 2. Modeling of variable drilling depths in system optimization models with deep geothermal plants

(A) Compilation of drilling cost functions in relation to depth in different energy system optimization models.

(B) Focus on the range between 2,400 and 4,600 m depth to compare the cost functions from the literature with a probability function for well costs[51] (blue area). Both figures were created based on the cost functions stated in several articles.[19,27,28,30–33,46,47,52,53] A factor of 1.09 was used for the conversion from euros to US dollars. We used a plot digitizer tool and a second-degree polynomial fit to determine the function of Ricks et al.[19] The cost functions in Kleinebrahm et al.,[27] Weinand et al.,[30–33] Molar-Cruz et al.,[28] and Gładysz et al.[46,47] were used for sedimentary basins and those of Miranda et al.[52] for crystalline basements. In the case of Ricks et al.,[19] the geological setting was not explicitly stated, but given its application to an EGS scenario, we assume it pertains to crystalline basement as well.

(C) Deviation between the linear drilling cost function in IEA[53] and the nonlinear function in Ricks et al.[19]

provision of electricity. In binary power plants, the geothermal heat is transferred to a low-boiling-point working fluid in a closed cycle.[43] In the majority of studies in which the binary power cycle is specified in more detail, the organic Rankine cycle is used. Only one article[44] implements the option of installing a Kalina cycle as an alternative to the organic Rankine cycle. In only three articles, the geothermal heat is converted into electricity in flash power cycles. This low number is remarkable, as most of the existing geothermal power plants around the world (~61%) use the flash-steam technology.[45] In open flash-steam power cycles, high-pressure geothermal water is vaporized in a separator and then used to supply electricity via a turbine.[45] Furthermore, Gładysz et al.[46,47] model the Brayton cycle for the provision of electricity. While the organic Rankine cycle and Kalina cycle often rely on toxic, flammable, expensive, and high-global-warming-potential working fluids, the Brayton cycle can utilize supercritical CO_2, which is non-toxic, non-flammable, cheap and abundant, and has a global warming potential of 1, and ozone depletion potential equal to 0.[48] In the two articles with CPG,[21,22] a direct CO_2 power cycle is implemented without providing more detailed information on the specific type or name of the power cycle.

Temperature and drilling depth

The reviewed studies examine both low-temperature (<150°C[42]) and high-temperature geothermal sources (>150°C[42]). Half of the 22 articles that specify temperatures consider multiple temperatures or a range of temperatures, while the others consider only one specific temperature (see Table 1). The maximum temperature analyzed in the studies is close to the threshold value of 150°C with an average of 187°C and a median of 175°C. Only Temiz and Dincer[49] consider a very high geothermal temperature of 550°C in a supercritical system.

Allowing the selection of the drilling depth and thus the achievable temperature to be freely optimized leads to an increase in complexity due to the introduction of (additional) decision variables.[50] In fact, only nine of the studies examined a variable drilling depth; in the other articles, drilling depth is a fixed parameter (see Table 1). But even in these nine studies, the drilling depth is not always included as a variable in the energy system optimization: Ricks et al.[19] compute costs and supply curves for 1 km depth intervals and 25°C temperature intervals, but in the interest of minimizing computation time only include the least-cost resources in each of the 11 model regions representing the United States Western Interconnection.

Dalla Longa et al.[36] and van der Zwaan et al.[5] implement deep geothermal plants in the integrated assessment model TIAM-ECN. The geothermal options are modeled as nine temperature-depth combinations, each associated with a set of applications (e.g., heating or electricity generation), specific technologies with different costs and region-specific resource potentials (see Figure 2B). The TIAM-ECN model can choose any of these technologies, depending on the available potential and the application demand in the specific regions. This setup is the same in both papers, but for Dalla Longa et al.[36] the authors also estimated the geothermal resource potentials in Europe using high-resolution GIS data.

Kleinebrahm et al.[27] and Weinand et al.[30,31,33] model the drilling depth as a continuous variable in their investigation of municipalities with the energy system models RE^{3}ASON and ETHOS.FineRegions. In the studies by Weinand et al.,[30,31,33] municipalities in the area of three different aquifers in Germany are analyzed. While the temperature gradients (°C/km) were modeled linearly for the North German Basin and the Molasse Basin, there is a temperature anomaly in the Upper Rhine Graben and high temperatures are reached at shallow drilling depths. For the latter aquifer, three temperature gradients are therefore implemented based on real data, which apply to different depth ranges and of which only one range can be selected in the model using decision variables. In Kleinebrahm et al.[27] and Weinand et al.,[30,31,33] the drilling depth up to 5,000 m is divided into five 1,000 m ranges in order to be able to approximate the nonlinear drilling cost function in a linear optimization problem. However, this has no influence on the selectable drilling depths. Weinand et al.[32] implement the geothermal system similarly to the previously described studies, but instead of continuous variables for drilling depths and temperature, 400 discrete options per system are given in 10 m increments from 1,000 m to 5,000 m depth. The variable modeling of the drilling depths represented a great added value in the studies, as different cost-optimal drilling depths were actually selected depending on the local conditions.

For the optimization of large-scale deep geothermal district heating systems, Molar-Cruz et al.[28] also use different drilling depths. These are not used in the optimization problem, however, and are only determined in advance for different areas of the German Molasse Basin. The depth of the aquifer in the north of the basin is around 500 m, in the region around Munich between 2,000 and 3,000 m and over 5,000 m in the southern part at the Alpine border. A special feature of Molar-Cruz et al.[28] is that they also model the volume flow in spatial detail.

Cost models

Most of the reviewed studies implement the geothermal plants with linear cost functions in $/MW in the optimization models. Other studies fix the drilling costs, for example, but include detailed representations of other cost components, such as Marty et al.[54] focusing on the costs for the construction of district heating networks. In Tian et al.,[20] most of the cost parameters are fixed but the number of wells is optimized. Only a few studies use detailed cost models, but some still optimize the design of the systems before the actual energy system optimization, as in Oyewo et al.[55] and Ogland-Hand et al.[22] In addition, some studies assume future cost developments for deep geothermal plants. For example, Weinand et al.[33] assume a decrease in costs of 0.5% per year, while Dalla Longa et al.[36] and van der Zwaan et al.[5] assume a learning rate of 13% between 2010 and 2050, following the learning-by-doing principle that has been empirically observed for fracking technology, as used to increase the production of natural gas from deep geological formations.

In the following, we focus on the representation of drilling costs in the more detailed cost models (see Figure 2), as these can account for more than 60%–75% of the total costs of deep geothermal projects.[51] We introduce here the drilling cost equations used in the various models and provide a visual comparison of the resulting estimates of cost as a function of depth in Figure 2. In most cases, the cost models used are derived from existing project data. Weinand et al.[30–33] and Kleinebrahm et al.[27] implement the drilling costs C_D in € based on Schlagermann[56] and Eyerer et al.[57] depending on the variable drilling depth z_D and the fixed distance d_D (1,500 m in the cited articles) between the production and injection well (see Equation 1).

$$C_D = 610{,}000 + 1.015 \cdot \left(1.198 \cdot e^{0.00047894 \cdot \sqrt{z_D^2 + d_D^2}} \cdot 10^6\right) \quad \text{(Equation 1)}$$

The fixed costs of €610,000 are only incurred for the first well and, since drilling is done at one site, the second term is multiplied by 0.9 for the second well due to a cost reduction of 10% based on Schlagermann.[56] Since the drilling costs were linearized for five depth ranges for the linear optimization, the deviation from the actual nonlinear cost function is between −2% and +1%.[30] By providing the 400 discrete options as drilling depth in Weinand et al.[32] this deviation could be almost eliminated.

The adapted cost model for the drilling costs in Molar-Cruz et al.[28] is also based on Schlagermann[56] (see Equation 2). The costs are given in €.

$$C_D = \left(1.228 \cdot e^{0.0004354 * z_D} * 10^6\right) \quad \text{(Equation 2)}$$

Miranda et al.[52] use the models from Limberger et al.[58] with d_D = 1,000 m to estimate the drilling costs in M€ (see Equation 3). The authors differentiate between costs for boreholes up to and beyond 5,200 m depth.

$$C_D = \begin{cases} 1.5 \cdot \left(0.2 \cdot (z_D + d_D)^2 + 700 \cdot (z_D + d_D) + 25{,}000\right) \cdot 10^{-6}, & z_D \le 5,200\ m \\ 10^{-0.67 + 0.000334 \cdot (z_D + d_D)}, & z_D > 5,200\ m \end{cases} \quad \text{(Equation 3)}$$

Gładysz et al.[46,47] use linear drilling costs of 1,400 €/m for wells with a depth beyond 5,000 m. Ricks et al.[19] use adjusted drilling cost functions in M$ based on Lowry et al.[59] (see Equation 4).

$$C_D = 0.3851 \cdot z_D^2 + 0.0369 \cdot z_D + 2.3506 \quad \text{(Equation 4)}$$

As the cost function in Ricks et al.[19] is only shown in a figure, but the exact function is not given, we used a plot digitizer tool and a second-degree polynomial fit to determine the function. In addition to the drilling costs, the authors also assume $4.5 million of stimulation costs for the injection well. In Equation 4 and Figure 2B, however, only the baseline cost function for the production well is given for comparison purposes. As described above, despite the detailed cost curve, the drilling depth for the various regions is fixed in the energy system optimizations in Ricks et al.[19] for computational reasons.

The cost models used are based on various years, for example, the Schlagermann[56] model is from 2011. Therefore, contrary to some of the articles discussed above, the cost functions should not simply be adopted, but exchange rates, inflation, and geothermal drilling indices should be used to account for actual cost changes since the reference years. For example, Ricks et al.,[19] who consider EGSs, take into account the oil drilling index. This and the fact that Ricks et al. is the most recent study probably leads to the lower costs in Figure 2A. The cost ranges are from 15.5 k$ to 3.4 M$ at a depth of 200 m, from 1.5 to 5.1 M$ at a depth of 2,000 m and from 9.6 to 16.8 M$ at a depth of 5,000 m, with Ricks et al.[19] representing the minimum and Weinand et al.[32] the maximum. Due to the exponential nature of the cost models, there are more fundamental deviations from a drilling depth of 5,000 m. The steep increase in drilling costs at greater depths is due to the cumulative effects of reduced penetration rates, increased casing and pressure control requirements, and heightened operational risks. These are further exacerbated by extreme downhole conditions, such as high temperatures, corrosive fluids, challenging lithologies, and long well trajectories. These conditions require advanced materials, specialized technologies, and carefully designed drilling strategies to prevent failure.[53]

How uncommon an accurate nonlinear representation of drilling costs is can also be seen in the flat-rate assumption of 2,000 $/m in the latest IEA report on the future role of deep geothermal plants in the global energy system.[53] When comparing such a linear cost function with the nonlinear cost function by Ricks et al. from the same year, significant differences emerge. Figure 2C shows that the IEA's linear cost function over- and underestimates drilling costs at lower (by +420% at a depth of 1 km) and higher depths (by −50% at a depth of 10 km), respectively. This demonstrates that it is essential to take nonlinear relationships into account in the future in order to avoid making incorrect statements regarding costs. Therefore, we hope that this first comparison of drilling cost functions used in energy system models can support future research in carefully selecting the appropriate function. Especially when considering deep wells, sensitivity analyses should be used to examine the influence of different cost functions on the results. The uncertainties of the cost models (see Figure 2B) are further discussed below.

DISCUSSION

In this review on the state-of-the-art in modeling geothermal plants in energy systems, we have identified several research gaps. In addition to the research gaps already mentioned above concerning nonlinear temperature-depth dependencies and the detailed depiction of drilling costs, there are other important aspects that have been largely neglected in studies to date. This section discusses the consideration of technological innovations, uncertainties, as well as environmental and social impacts in energy system analyses, and presents various data sources that could support the addressing of some of the research gaps in the future. Finally, we use the knowledge gathered in this review to provide an outlook on the future role and competitiveness of deep geothermal energy.

Consideration of technological innovation

Our review has shown that recent technological innovation in resource utilization is already being investigated in energy systems. In addition to conventional hydrothermal resources that are already commercially available, emerging EGSs and closed-loop geothermal systems such as CPG are also being considered (see Table 1). The latter two technological innovations have the advantage that they are less dependent on location, as they do not rely on natural hydrothermal reservoirs.[53] The following research gaps deal with technological innovations that have not been considered in energy system analyses so far.

Drilling cost reduction

As described above, drilling costs account for a major portion of the investment in deep geothermal projects, making cost reduction through technological innovation highly relevant. For example, studies indicate that EGSs will become cost-competitive in electricity markets if drilling costs are reduced by approximately 60%.[60]

As the time on site is one of the main predictors of overall costs, the efforts to reduce drilling costs focus on increasing penetration rates, extending drill-bit lifetime, and accelerating operations and reducing downtime by improving supply chain efficiency.[53] The need for innovative drilling solutions depends on the characteristics of the reservoir, such as its depth, temperature, the corrosiveness of the water, and the hardness and brittleness of the rock.[53] Emerging hybrid conventional and no-contact drilling technologies such as high-pulsed power drilling or millimeter-wave laser drilling are currently under development and could substantially reduce costs in the future.[53,61] As a further approach to reducing costs, the reuse of abandoned oil and gas wells for geothermal energy production should also be considered in future system analyses.[62]

Just recently, for example, new baseline drilling costs for the geothermal power industry in the United States were published.[63] Therefore, the cost functions for energy system models discussed above should be continuously updated to reflect the most recent innovations.

Flexible operation

In general, geothermal plants are implemented as base-load technologies in energy systems. However, in 2012, operators of a conventional geothermal system in Hawaii achieved a flexible energy supply by integrating new bottoming units with the existing geothermal system.[13,64] Bottoming units capture and use leftover heat (enthalpy) from geothermal brine after the main steam cycle has extracted energy. The operators also developed an advanced control approach that enabled participation in automatic generation control. This setup allowed remote dispatch, rapid ramping, and spinning reserve management. Thus, the geothermal facility could be dispatched for more than just base load.

However, this solution has never been considered in energy system analyses. In fact, the flexible operation of future EGS-based systems could be more promising. A growing, albeit limited, number of studies[19,65–67] are examining these innovative, flexible EGS-based plant designs that incorporate load-following capabilities and long-duration energy storage. In this case, energy would be stored in the form of accumulated, pressurized geofluid, which can be released to provide a flexible load-following supply.[66] This stored potential energy from underground pressure can also be combined with the leveraging of heat from the surrounding rock formations.[53] Recent energy system analyses have already shown that such designs could significantly increase the deployment of geothermal plants in future energy systems with high shares of variable renewable energy capacity.[19,21,65] Thus, these designs should be considered in future energy system analyses. The flexibility in providing heat and/or power could also be economically beneficial when combined with other emerging technologies such as direct air capture, which has substantial (high temperature) heat demand.[68,69]

Raw material extraction

The energy transition requires large quantities of critical raw materials.[70,71] However, conventional processes for extracting materials are often associated with high emissions, high demand for land and water,[32] and could threaten biodiversity.[72] Geothermal brines often contain high concentrations of extractable raw materials such as lithium (Li), rubidium (Rb), cesium (Cs), and strontium (Sr).[73–77] In fact, current assessments indicate that these materials would remain sustainably available: research on the lithium content shows that the concentration of lithium in the extraction borehole would decrease by 30–50% in the first 10 years of operation, but would remain constant thereafter due to the constant supply of fresh deep water from other directions.[78] The Upper Rhine Graben in Germany and France, and Salton Sea in the Imperial Valley (California) of the United States, rank among the most promising areas in the world for the unconventional production of lithium, and possibly of others of the above raw materials.[76] As a result, there are already some geothermal lithium activities in these areas in the form of initial test and demonstration projects for extracting lithium in geothermal plants (see Figure 3A). Prominent examples include the Rittershofen plant in the Upper Rhine Graben (France) as part of the European Geothermal Lithium Brine (EuGeLi) project, the Bruchsal power plant in the Upper Rhine Graben (Germany) as part of the UnLimited Project, or the Horstberg research borehole in Northern Germany as part of the Li+Fluids project.[32,53] In Germany, lithium concentrations of up to 237 mg/L have already been measured in geothermal brines, and in Europe even up to 480 mg/L.

Despite the high demand for critical raw materials, material demands in energy system scenarios are mostly analyzed ex-post, and the incorporation of material supply or demand into optimization models is rarely done endogenously.[70] This is also evident in the current review, as only Weinand et al.[32] included the direct extraction of lithium from hydrothermal water into their energy system analysis. The article shows in investigations of more than 300 regional energy systems that geothermal plants become cost-competitive through the extraction and sale of lithium. In this case, the simultaneous provision of geothermal heat and electricity would displace large proportions of wind and solar plants as well as heat pumps and storage systems. This has been confirmed in many sensitivity analyses of uncertain lithium extraction parameters. However, no decrease in lithium concentration after a certain period of time was considered in Weinand et al.[32] Even though the analysis of different lithium concentrations in Weinand et al.[32] did not affect the conclusions regarding the economic viability of geothermal plants with lithium extraction, the reduction in concentrations in the first 10 years of operation[78] should be taken into account in future investigations. Although Weinand et al.[32] is the only study examining geothermal plants with lithium extraction in energy systems, there are also studies on the economic viability of individual plants. Toba et al.,[80] for example, show that lithium extraction from geothermal water could generate benefits of up to \$258–\$311 million for plants in the United States, with projections of 23–43 million electric vehicles by 2030.

The analyses by Weinand et al.[32] further show that installing around 30 geothermal plants with direct lithium extraction in the Upper Rhine Graben in Germany would enable the production of more than 9 kt/a of lithium (conversion factor of 5.3 to lithium carbonate), sufficient for the manufacture of about 1.2 million electric vehicle battery packs per year. The IEA[53] estimates that geothermal plants could provide around 47 kt/a of lithium in 2035 if all announced projects worldwide are realized. This would correspond to around 5% of total global demand in 2035.

The production of lithium from geothermal water involves a sequence of two major processes: (1) extraction of lithium from geothermal brines and (2) refining of the resulting solution, with its conversion into the final product, lithium carbonate or lithium hydroxide. The

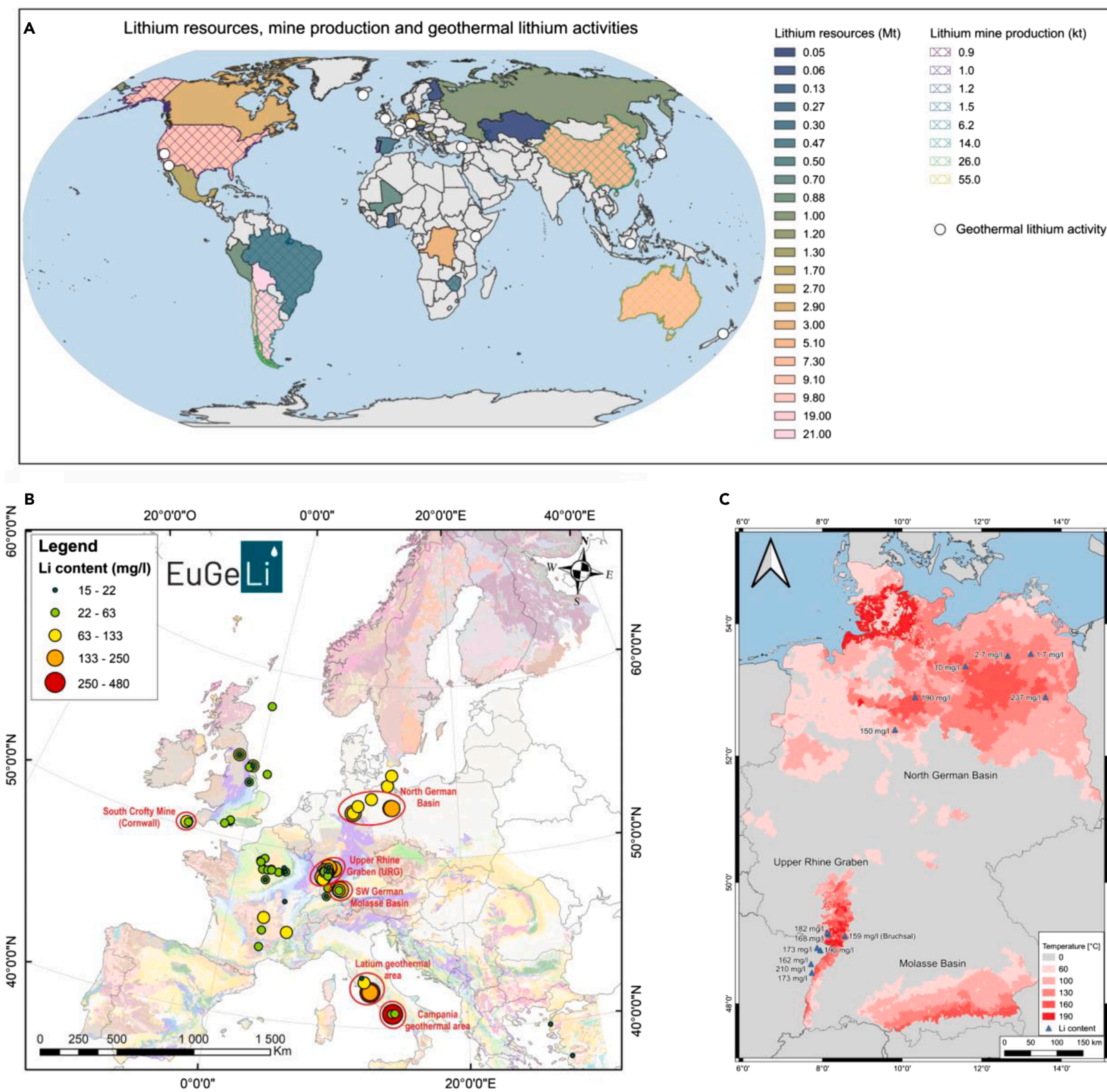

Figure 3. Global geothermal lithium resources, activities, and concentrations

(A) Global conventional lithium resources and mine production, as well as geothermal lithium activities.[32]
(B) Lithium-bearing geothermal brines in Europe.[79]
(C) Achievable hydrothermal temperatures in Germany at a depth of up to 5,000 m and measured lithium contents.[32]

second sequence is similar to that of the processes already well-known and implemented for the purification of enriched brines obtained from salars. Direct lithium extraction technologies are numerous and, for the most part, still in the testing phase to be adapted to the geothermal context. Indeed, extracting lithium from geothermal waters involves many technical challenges, including in particular the high temperature and pressure of the fluids under operating conditions as well as their chemical composition, notably their high salinity. The most promising methods for lithium extraction can be grouped into three main categories: adsorption, ion exchange, and liquid-liquid extraction,[75,81] which are described in detail in the supplemental information.

In addition, interest in rubidium extraction has recently increased due to its potential applications, e.g., in semiconductors.[82] However, its separation from aqueous natural resources is challenging due to its relatively low concentration and high separation cost. Therefore, the development of efficient and cost-effective methods for the selective separation of rubidium is timely.[83] Among the innovative extraction processes, a new general method for the separation of pure rubidium chloride from sodium- and potassium-rich brines has been proposed, based on rubidium adsorption via ion exchange performed using zinc-hexa-cyanoferrate material, also known as Prussian blue analogs.[82] Further information on material extraction can be found in the supplemental information accompanying this article.

Consideration of uncertainties

Geothermal power, heat, and material supply are associated with significant uncertainties due to the variability of key hydraulic parameters, such as fluid flow rates and injectivity indices, even between neighboring areas. In fractured environments, understanding deep fluid circulation, fault networks, and recharge areas is crucial for assessing geothermal potential. To minimize risks, project failures, and uncertainties about resource extractability and sustainability, it is essential to analyze site-specific geological features and hydrodynamic behavior rather than relying on regional data.[76] The cost uncertainty associated with EGSs in crystalline rocks is usually higher than with conventional systems, as permeability must be engineered via hydraulic stimulation (which could be unsuccessful), drilling hard rock is more expensive and technically challenging, and less empirical cost data are available. This uncertainty increases with depth due to increasingly complex well designs and higher formation temperatures and pressures.[51] Material extraction from geothermal brines faces additional challenges, such as limited exploration wells and insufficient geoscientific data, which increase project risks. Advanced geophysical methods such as seismic and 3D geomodelling are needed to improve resource characterization.

To reduce the risks of drilling failures, especially for EGSs, establishing a credit guarantee fund for geothermal drilling could encourage technological innovation, investment, and deeper exploration by lowering the financial risks involved. A variety of successful risk mitigation models have been implemented around the world to address the significant initial risks associated with geothermal drilling. Iceland pioneered a public loan guarantee scheme in the 1960s, whereby unsuccessful wells were state-subsidized. This model enabled near-universal geothermal heating.[84] Prior to 1981, France set up a Short Term Fund to cover geological drilling risks. Together with other measures, this enabled the installation of 500 MW_{th} of geothermal heat capacity.[85] Indonesia's Geothermal Fund[86] and Turkey's World Bank-funded Risk Sharing Mechanism[87] also use a "contingent grant/loan" model, whereby developers only repay support if wells are successful. Through the Global Geothermal Development Plan, the World Bank provided financing, knowledge, and technical assistance to cover the costs and risks of exploratory drilling. This resulted in the development of around 240 MW_e of geothermal power capacity in Turkey and 600 MW_e in Indonesia.[88] Additionally, a partial risk guarantee by the African Development Fund has enabled the development of the 105 MW_e Menengai Independent Power Producers project in Kenya, set to provide power to 500,000 households and 300,000 businesses.[89]

In the reviewed studies, uncertainties or risks were hardly taken into account at all. If uncertainties were considered, either conservative costs were assumed to account for exploration risks[27,29–33] or various sensitivity analyses were carried out on input parameters. Ricks et al.,[19] for example, consider different scenarios for drilling costs, subsurface favorability, and market opportunity. Dalla Longa et al.[36] also consider the fact that in practice only a small part of the subsurface can be effectively exploited. This is modeled with an ultimate recovery factor that varies between 0.01% and 1% in the scenarios. In Miranda et al.,[52] a Monte Carlo simulation is used to account for the uncertainty in well or stimulation costs. Figure 2B shows that the derived cost functions for the drilling are slightly in the range of the median of the probability distribution of drilling costs, or below. The study on the probability distribution of drilling costs is from 2016,[51] i.e., predates the articles with implemented cost functions. Nevertheless, the latter studies assume relatively low, albeit probable, costs. However, the studies do not make it clear whether technological advancements have reduced drilling costs or whether inflation has increased them. Other interesting approaches to accounting for uncertainty in drilling costs include the implementation of a probability of drilling success.[90]. Energy system optimization studies on the role of geothermal energy should in future draw on further established approaches for quantifying uncertainties, such as stochastic or robust optimization,[50] Bayesian Network methods on large scenario ensembles,[91] or modeling to generate alternatives.[92–94]

The extent of the uncertainties in the model results could also be assessed by validation with real-world data. However, information on validation is largely unavailable in the reviewed studies. Tian and You[24] also correctly state in their study that validation of future energy system designs is only possible to a very limited extent. Nevertheless, there are a few positive examples where the geothermal plant and energy system models could be partially validated. The developed models for local temperature-drilling depth correlations,[30,32] investment in the plants,[30] costs of geothermal district heating networks,[28,29] or energy demand in communities[27,32] were validated using real-world data. Ricks et al.[19] compared their modeled in-reservoir energy storage and flexible well-field operations with numerical simulations. In addition, modeled plant efficiencies were validated with literature values[49] and heuristic results for district heating design based on exact mathematical optimizations.[54]

Consideration of environmental and social impacts

Environmental impacts

Generally, energy system models do not yet include life-cycle-based environmental aspects into their optimization or other algorithms. Ultimately, however, the role of geothermal energy in global energy transition will also be determined by its impacts on the environment—locally as well as through related supply chains (see Table 2). For geothermal plants, this means that all phases from seismic exploration and exploration wells, construction, operation and maintenance, and end-of-life should be included in a life cycle assessment (LCA).[14,16] Recent LCA analyses showed that the operational phase of a geothermal plant has a significant influence on climate impact, human toxicity, and acidification. This is particularly true for flash and dry steam plants, which emit varying amounts and types of non-condensable gases over their lifetime. Thus, the need for dynamic LCA instead of static LCA has been emphasized[14]. Such dynamic approaches should reflect important changes during the operational phase of the power plant, both in the foreground (e.g., physical plant properties) and in the background (e.g., changed electricity supply mix or supply chains of materials needed for maintenance). Modeling geothermal plant direct emissions varying over the lifetime of the plant is important, and coupling the LCA to a technical model of the power plant is important to capture; for instance, net capacity decline due to changes in flow rate or reservoir pressure. It is crucial that such dynamic LCA on the technology level will be implemented into energy system models in a next step in case such models want to include life cycle environmental results or even optimization (e.g., by coupling LCA models such as GREET[16,95] with energy system frameworks such as TIMES[96]). As to our knowledge, no streamlined approach or even common methodology for this coupling exists yet.

Binary plants do not emit any non-condensable gases from their closed-loop circulation. The well construction, with its drilling energy and materials consumption, is most decisive in the assessed impact categories. Especially, the LCA results for EGSs depend heavily on the technical modeling of the plant (plant capacity vs. drilling depth, and well drilling/completion) as well as the drilling energy source (diesel generator or electricity from various sources). This shows once again the need for variable drilling depths in energy system optimizations, especially if LCA impacts are to be included in the future. Given that many EGS-based plants will only be built in future when electricity mixes and technologies may have changed compared with today, the need for prospective LCA modeling of the construction phase in the future with accordingly adapted data is underpinned.

A comparison of EGS-based plant electricity with other electricity-producing technologies shows that generally geothermal electricity supply is helpful in decreasing environmental impacts compared with fossil fuel sources, while being in the same range of various impacts as—or even lower than—other renewable energy sources depending on the construction phase and the net capacity of the plant.[97]

The environmental impacts of material extraction from geothermal brines also need to be studied more intensively in the future. A recent study[98] showed that, based on uncertain assumptions about drilling requirements and of fossil energy use, the climate impacts of lithium extraction from geothermal brines could range from 5.3 to 59 kg CO_2eq/kg lithium carbonate, compared with the probably underestimated 2.1–11 kg CO_2eq/kg lithium carbonate in existing datasets. The wide range of potential impacts underscores the need for early assessment of these novel technologies.[98]

Table 2. Global warming potential of geothermal plant types

Plant type	Global warming potential (kg CO_2-eq/kWh)	Comment
Dry steam	375 (31–795)	heavily depending on the modeling of direct non-condensable gas emissions, which depend on the highly site-specific composition of the geofluid as well as abatement systems in place. No study distinguished between anthropogenic and natural NCG emissions
Flash	110 (26–245)	
Binary—organic Rankine cycle (ORC) plants (in general)	49 (6–97)	leakage of working fluid possible
Binary—EGS-based plants	32 (8–52)	construction phase most decisive (drilling energy, well material consumption). Leakage of ORC working fluid possible; leakage of geothermal fluid possible, but this is not relevant for climate change when water is used

This is a summary of results from 30 LCA studies as shown in the review paper by Gkousis et al.[14]

Social aspects

Geothermal energy currently enjoys high overall socio-political acceptance in many countries, at a level that is similar to other renewable energy sources.[99–101] However, as a lesser-known technology, geothermal energy is particularly susceptible to potential rapid changes in acceptance, once the technology becomes discussed more widely in society,[102,103] and since it is especially vulnerable to negative information.[104] One of the key issues that raises local resistance to new geothermal projects, but can also substantially reduce the overall socio-political acceptance, is the risk of induced seismicity,[105] for example, during hydraulic fracturing for EGSs.[106] Although geothermal seismicity applies only to deep projects[107] and is rarely more than a nuisance, larger events that lead to damage to the surrounding buildings cannot be fully ruled out.[108] Current projects hence apply elaborate seismicity management strategies, including one-way communication and two-way engagement of the affected communities.[106,107] Further mitigation strategies include the creation of new fracture networks preferably in previously unfractured rock, microseismicity monitoring, and multistage stimulation, which limits the amplitude of potential earthquakes.[53] Nonetheless, managing seismicity during hydraulic fracturing remains an ongoing challenge for EGSs,[13] and seismicity has been one of the most common causes for abandoning geothermal projects.[109,110] There are negative spillover effects on the acceptance of shallower geothermal systems too,[111] as the general public does not necessarily distinguish different types of geothermal systems. Negative spillover effects on overall geothermal acceptance are also observed from other technologies, like shale gas.[112]

Although more purely social scientific research on geothermal energy would be needed,[113] there have been several attempts in the literature to combine social acceptance considerations with modeling. Onodera et al.[114] examined opportunity costs that are incurred if deep geothermal energy is not used. Weinand et al.[32] capped the potential role of geothermal energy due to both technical feasibility and social opposition. Mignan et al.[115] incorporated the costs of seismic risk mitigation in levelized costs of electricity for EGSs. A series of studies in Switzerland[101,116,117] and the United States[101] have taken a holistic approach and aimed to find suitable EGS sizes and locations by modeling the balance between the economics of EGS-based plants, their energy, and environmental benefits and costs, as well as seismic risk and survey-based acceptance. The studies revealed an overall socio-technical preference for medium-size plants in rural areas or for larger plants in remote areas. Finally, Volken et al.[102] investigated how the public judges EGSs, its energy, and environmental, economic impacts, and seismic risks compared with other electricity technologies and found that EGSs is, despite its risks, perceived as part of the future electricity mix.

In addition to induced seismicity and other environmental factors, noise and land use can also influence social acceptance.[53] Although there have already been some studies on the land consumption of renewable energies,[118,119] comparisons with alternative technologies (e.g., the vast land consumption of lignite mining) should also be considered in future studies on geothermal plants in order to inform the public about possible alternatives.

Data sources for addressing research gaps

While the exact suitability of geothermal reservoirs and the costs of constructing plants cannot be estimated on a large scale, some analyses and datasets on geothermal temperatures and potentials do exist. In addition to national analyses, e.g., for Germany on geothermal temperatures (see Figure 3C)[120–122] and EGS potentials,[123] for Ecuador on geothermal resource inventory,[124] or for the United States on geothermal temperatures[125] and EGS potentials,[65] several continental and global datasets and studies are available. For Europe, based on calculated subsurface temperatures down to a depth of 10 km on a regular 3D hexahedral grid with a horizontal resolution of 10 km and a vertical resolution of 250 m, an economic EGS potential of 522 GW_e below 100 €/MWh_e was determined.[58] A global estimate[1] of EGS theoretical, technical, economic, and sustainable potential is provided with a horizontal resolution of 111 km and a vertical resolution of 1 km following a standard protocol.[126] In 2050, the global economic potential of EGS-based plants that can produce electricity at 50 €/MWh_e (150 €/MWh_e) or lower is estimated to be 4.6 TW_e (108 TW_e). The latest study on the global techno-economic potential of EGSs,[127] which includes a detailed assessment of land eligibility, finds that, on average, 27.4% of the Earth's land surface is suitable for EGSs. This varies from below 5% in North Africa to 72% in the Central African Republic. The article also shows that the global technical capacity potential is 102 PWh_e/a, with 17 countries worldwide having a potential below 50 €/MWh_e (see Figure 4). A comparison of the potential shown in Figure 4 with the currently installed systems shown in Figure 1 reveals that there is still considerable cost-effective potential, particularly for EGSs, in regions such as Russia, South America, and Africa, where hardly any installations have yet been realized. Another study estimates the spatially highly resolved global theoretical potential of low-enthalpy geothermal heat (<150°C) available in sedimentary aquifers suitable for direct use to be 5×10^6 EJ.[2]

In addition, a European[76,79] and a global atlas[128] of lithium geothermal fluids have been published recently. This could enable a larger-scale techno-economic analysis of lithium extraction in energy system models. The European atlas (see Figure 3B) also contains information on the correlation between high and low lithium deposits and other minerals. More recently, in 2023, a European Fluid Atlas, which includes the data of about 3,000 deep geothermal wells as a spatial dataset and their attributes (fluid, rock, and reservoir properties) was developed within the framework of the H2020-REFLECT project.[129] While the studies mention the key role of reservoir temperature, fluid salinity, and reservoir rock type on the concentrations of dissolved lithium, the Atlas has not yet been used

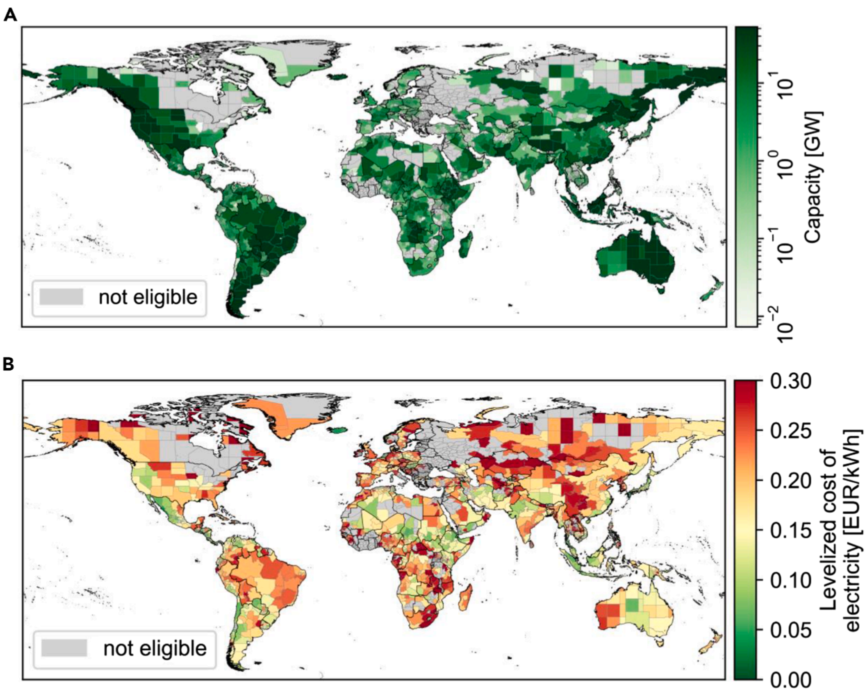

Figure 4. Global techno-economic potentials for enhanced geothermal power generation

(A) Global capacity potential, in total 12 TW_e or 102 PWh_e/a of electricity.[127]

(B) Levelized cost of electricity with cost assumptions for the year 2050.[127]

to address data gaps, for example, by mapping the spatial correlation between lithium concentration and temperature. This would be possible, however, as several European maps of temperature distribution[130] and geothermal heat flow density[131] are available.

The future role of geothermal plants

Geothermal plants are increasingly viewed as an important component of future energy systems given their potential to provide continuous, i.e., non-intermittent, and largely carbon-free energy. Currently, the technology is gaining momentum globally, particularly in regions such as the United States, Europe, Southeast Asia, and Eastern Africa, which have significant untapped geothermal potential. Kenya, for instance, is rapidly expanding its geothermal capacity and plans to nearly double its output by 2030 as part of its green energy transition,[37] already (2022) covering roughly 45% of its electricity supply with geothermal plants.[4] Africa as a whole is expected to surpass Europe in installed geothermal capacity by 2030,[132] underscoring the growing global recognition of geothermal energy's role in achieving renewable energy targets.

Most of the reviewed studies show that geothermal energy can at least be partly cost-competitive with other energy supply technologies (see Table 1), particularly when favorable subsurface conditions are available, such as high temperatures and flow rates at shallow depths. For instance, projections for the European[36] and global[5] electricity systems estimate that deep geothermal power could contribute between 4–7% and 2–3% of the total electricity by 2050, respectively. For Central America, a study suggests that, in cost-optimal scenarios, about 6% of the potential for EGSs could be exploited.[55] However, the long-term viability of geothermal energy, especially if based on EGSs, will largely depend on its ability to scale, reduce costs, and adapt to regional conditions. Promising modeling approaches, such as temperature-depth optimization for large-scale electricity systems,[5,36] can support these efforts by optimizing drilling depths and plant designs across extensive regions. Similarly, cost-optimized district heating systems that integrate geothermal potential mapping,[28,90] highlight the importance of accounting for spatial mismatches and uncertainties in geothermal heating systems. Future large-scale analyses should also focus more on the role of district and industrial heating, which was underrepresented in the reviewed studies and could increase the cost-competitiveness of geothermal plants.[30,116]

The competitiveness of deep geothermal energy could be further enhanced through flexible operation, policy support, and innovation. By allowing geothermal plants to follow demand patterns and shift generation on daily and seasonal scales, flexible plants based on EGSs can displace more expensive energy resources, contributing to lower overall electricity costs. This operational flexibility, combined with high energy storage efficiencies, could position geothermal energy as a valuable player in balancing intermittent renewable resources such as various forms of solar and wind energy.[19] The results from life cycle analyses show that this would in general not come with significant trade-offs with regards to environmental footprint, as e.g., climate change impacts, (raw) material use through supply chains, and toxic effects are not expected to be higher than for other renewable electricity sources,[14] except for partially high non-condensable gas emissions, which need to be monitored and controlled.

Achieving the large deep geothermal potential will also depend heavily on reducing costs through technological learning and gaining policy support. For example, projections for the United States suggest that plants based on EGSs could provide up to 20% of the country's electricity by 2050, but this is contingent on significant cost reductions driven by early investments in high-quality geothermal resources.[67] On a global scale, according to the International Energy Agency, geothermal energy could meet up to 15% of global electricity demand growth by 2050, equivalent to the current electricity demand of the United States and India combined.[53] With around 70% cost reductions, plants based on EGSs could even become the least-cost dispatchable carbon-free energy source in fully decarbonized energy systems.[133] Full decarbonization policies, including mandates for carbon-free electricity, would likely accelerate the adoption of geothermal energy, especially in regions with favorable geological conditions. In addition, a comprehensive regulatory framework is needed to mitigate the environmental and financial risks associated with deep geothermal operations. Existing regulations often fail to address the high upfront costs and the risk of overextraction of geothermal resources, limiting the scalability of the technology. Reforms that protect geothermal resources and provide financial incentives will be essential to encourage industry growth and unlock the full potential of geothermal energy.[134]

Furthermore, technological innovations like the extraction of valuable minerals such as lithium from geothermal brine can further enhance the financial attractiveness of geothermal plants. Studies for Germany and the United States suggest that, in areas where lithium extraction is feasible, geothermal energy can become cost-competitive with other technologies, almost regardless of local subsurface conditions.[32,80] These additional revenue streams could play a crucial role in ensuring the economic viability of geothermal energy in the future.

CONCLUSION

Deep geothermal energy is gaining increasing attention in politics and public discourse. As our findings show, this is well justified: the technology is poised to play a far more significant role in the energy and materials transition than it does today. But precise modeling of geothermal plants remains highly complex, and oversimplifications risk misrepresenting their future potential. This article provides the

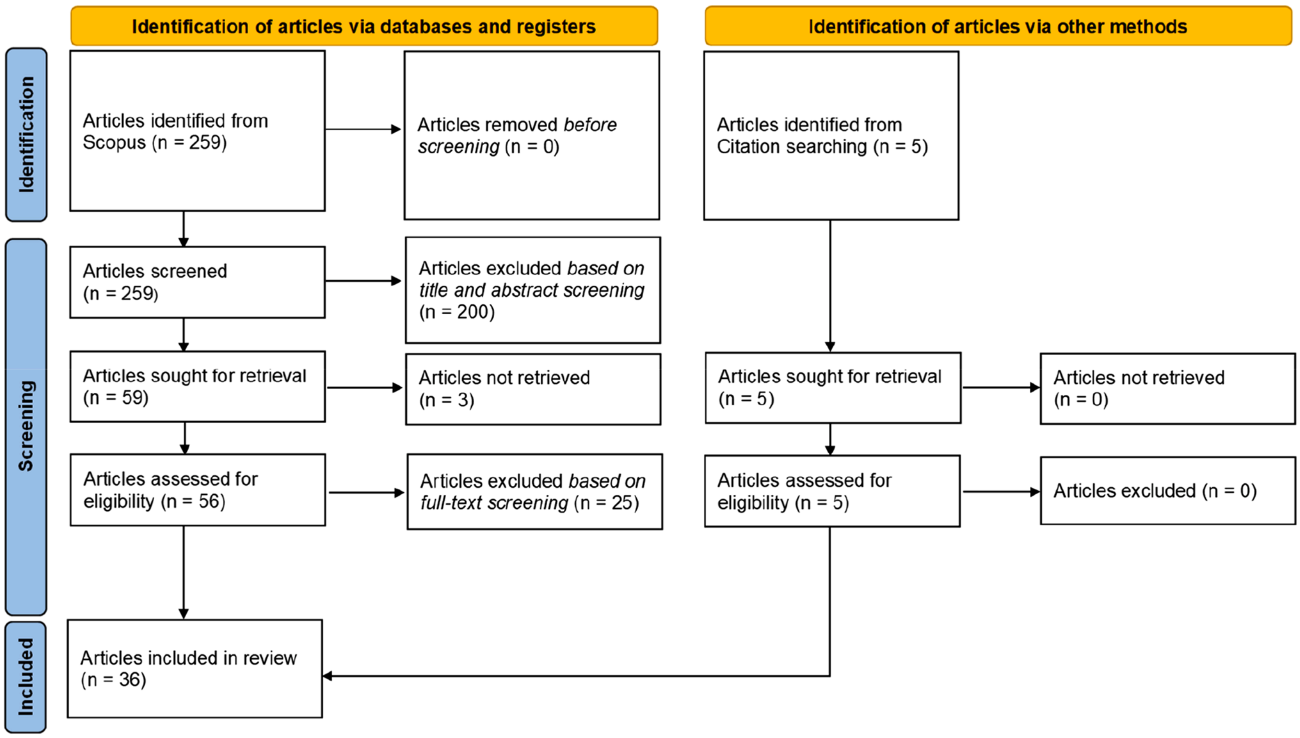

Figure 5. Flowchart for identifying and classifying relevant articles on modeling deep geothermal plants
The flowchart method isbased on the PRISMA 2020 Statement[135]

first comprehensive overview of modeling approaches for deep geothermal plants within energy systems. We show that current models often neglect nonlinear relationships, leading to underestimated drilling depths and costs, but we also highlight best practices that can guide more robust analyses. Looking ahead, we outline key technological innovations as well as social and environmental considerations that should inform system planning. Together, these insights equip energy system analysts and decision-makers with methodological and strategic guidance to better integrate geothermal energy into future energy transitions.

METHODS

For identifying the current state-of-the-art in techno-economic modeling of deep geothermal plants in energy systems (cf. Table 1), we follow the PRISMA 2020[135] methodology for identifying relevant articles and conducting a systematic review (see Figure 5). Potential articles were retrieved on March 23, 2024, using the following search query in the Scopus literature database:

TITLE-ABS-KEY((“deep geothermal” OR “geothermal plant” OR “geothermal power” OR “geothermal elec*” OR “hydrothermal power” OR “enhanced geothermal” OR “EGS” OR “hot-dry-rock” OR “magma”) AND (“energy system*” OR “electricity system*”)) AND (LIMIT-TO (DOCTYPE,“ar”)) AND (LIMIT-TO(LANGUAGE,“English”)).

This search resulted in 259 matches. Keywords that did not lead to any further matches such as “petrothermal plant,” “engineered system,” “hot-wet-rock,” “geopressurized,” or “deep heat mining” are no longer listed in the search query above. This review includes articles that focus on geothermal energy plants (first criterion) as part of energy system model analyses, i.e., in competition with other technologies (second criterion). The first criterion means that the studies should focus on geothermal plants and their techno-economic implementation. Studies that include geothermal energy plants in the plant portfolio but do not focus specifically on this technology cannot be identified, even with systematic literature searches (see below). The second criterion means that the energy system analyses should also include technologies other than deep geothermal energy, as otherwise the role of geothermal plants in future energy systems could not be fully assessed. This also means that analyses of individual geothermal plants are not relevant for this review.

During the initial screening of abstracts, 200 of the 259 articles were excluded because of an inappropriate focus based on the 2 criteria mentioned above. The methods and topics in focus were identified in the abstract and compared with the 2 criteria mentioned above. Articles that were excluded focused, for example, on individual plant analyses (e.g., Behrang et al.[136] or Aravind et al.[137]), specific chemicals (e.g., Bothra et al.[138]), or life cycle analyses (e.g., Lohse[139] or Rossi et al.[140]) without connection to system models. A closer examination excluded a further 28 articles that do not deal with techno-economic energy system modeling, where deep geothermal energy competes with other technologies and measures, but instead present purely thermodynamic analyses or assessments of resource potentials. Utilizing citation searching, an additional 5 articles were identified as relevant, resulting in a total of 36 suitable articles.[5,19–36,38,44,46,47,49,52,54,55,114,141–148] For the citation search, the studies from the reference lists of the 31 previously identified suitable articles were examined further for suitability.

Subsequently, the articles were classified according to categories in the Excel table provided in the supplemental material. The categories encompass general information regarding the methodology employed, the temporal and spatial scopes of the analyses, and an emphasis on details regarding the modeling of deep geothermal plants.

Due to the fact that only a few publications on flash power plants in energy system optimization were found, we carried out a further search in Scopus on November 6, 2024:

TITLE-ABS-KEY((“flash” OR “dry steam”) AND (“geothermal”) AND (“energy system*” OR “electricity system*”)) AND (LIMIT-TO (DOCTYPE,“ar”)) AND (LIMIT-TO(LANGUAGE,“English”)).

The search resulted in 38 documents, all of which were classified as not relevant for the present review on the basis of the criteria described above.

As with any review study, the number of articles found depends on the search query. We developed the search query in our systematic review in an iterative process. However, there will be some further studies that consider geothermal plants as one of many technologies in energy system modeling (e.g., Berntsen and co-workers[149–153]). Our review focuses on studies that explore geothermal plants within energy systems, with particular emphasis on the detailed implementation methodology of this complex technology. For this purpose, we believe we have conducted a suitable search and identified the most important studies.

ACKNOWLEDGMENTS

This work was supported by the Helmholtz Association as part of the program "Energy System Design."

DECLARATION OF INTERESTS

The authors declare no competing interests.

DECLARATION OF GENERATIVE AI AND AI-ASSISTED TECHNOLOGIES IN THE WRITING PROCESS

During the preparation of this work the authors used the tools "ChatGPT" and "DeepL" to check grammar and spelling in a few places, and to make improvements to readability and style. After using these tools, the authors reviewed and edited the content as needed, and take full responsibility for the content of the publication.

SUPPLEMENTAL INFORMATION

Supplemental information can be found online at https://doi.org/10.1016/j.ynexs.2025.100099.

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