

Beneath the surface

Geothermal's role in delivering
clean heating, cooling and power

JULY 2026



Energy
Transitions
Commission

 Insights Briefing

The Energy Transitions Commission (ETC) is a global coalition of leaders from across the energy landscape committed to achieving net-zero emissions by mid-century, in line with the Paris climate objective of limiting global warming to well below 2°C and ideally to 1.5°C. ETC's commissioners come from a range of organisations – energy producers, energy intensive industries, technology providers, finance players and environmental NGOs – which operate across developed and developing countries and play different roles in the energy transition. This diversity of viewpoints informs our work: our analyses are developed with a systems perspective through extensive exchanges with experts and practitioners. The ETC is co-chaired by Lord Adair Turner and Jules Kortenhorst who work with the ETC team, led by Faustine Delasalle (Vice-Chair), Ita Kettleborough (Director), and Mike Hemsley (Deputy Director).

***Beneath the Surface: Geothermal's Role in Delivering Clean Heating, Cooling and Power* constitutes a collective view of the Energy Transitions Commission and was developed in consultation with ETC Members. Members of the ETC endorse the general thrust of the arguments made in this report but should not be taken as agreeing with every finding or recommendation. The institutions with which the Commissioners are affiliated have not been asked to formally endorse the report.**

The ETC Commissioners agree on the importance of reaching net-zero carbon emissions from the energy and industrial systems by mid-century and share a broad vision of how the transition can be achieved. The fact that this agreement is possible between leaders from companies and organisations with different perspectives on and interests in the energy system should give decision-makers across the world confidence that it is possible simultaneously to grow the global economy and to limit global warming to well below 2°C. Many of the key actions to achieve these goals are clear and can be pursued without delay.

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Introduction

Clean electrification is the foundation of the transition to a global net-zero economy. Electricity's share of final energy demand is expected to rise from ~20% of final energy demand today to 60–70% globally by 2050.¹ This is largely driven by the electrification of industry and buildings, which together are set to represent ~80% of final electricity demand in 2050.²

Geothermal technologies can support this transition by delivering clean heating, cooling, storage and firm power where geology, demand and economics align.

Distinct geothermal technologies serve different applications. Shallow geothermal addresses space heating (in individual buildings or via street/district networks), cooling and seasonal thermal storage. Conventional hydrothermal serves electricity generation, district heating, direct industrial heat and district cooling in limited geographies. Next-generation systems can provide electricity generation, district heating and industrial heat.

Today, the combined contribution of geothermal energy technologies is modest: combined, they met 0.5% of global final heat consumption and 0.3% of global electricity generation in 2024.³ But there is scope for a larger role, with current estimates ranging from ~1% of each to 8% of global final heat consumption and 9% of global electricity generation in 2050. The question this Insights Briefing addresses is which geothermal technology can scale where, and what policymakers, investors and corporates need to do to unlock that potential.

The Insights Briefing covers the following insights, and is supported by four technology factsheets:

#1 Geothermal energy spans three distinct technology families with fundamentally different costs, maturities and geographical relevance – policymakers and investors should treat each on its own terms and potential.

#2 Shallow geothermal technology has a high potential to scale, especially ground-source heat pumps (GSHP) and underground thermal energy storage (UTES), but is currently under-deployed. The barriers are finance and siting.

#3 Conventional hydrothermal⁴ is mature and cost-competitive where geology allows, but geological constraints will keep its contribution below 1% of global heat consumption and power generation in 2050, with an emerging role in cooling.

#4 Next-generation geothermal⁵ can overcome geographic resource constraints, but current costs vary significantly depending on technology and location. These cost uncertainties will define the gap between optimism and reality.

#5 Geothermal has lower environmental impacts than fossil alternatives, but environmental and social risks have halted a small minority of projects in various countries. Community

¹ ETC (2021), *Making Clean Electrification Possible: 30 Years to Electrify the Global Economy*; ETC (2025), *Power Systems Transformation: Delivering Competitive, Resilient Electricity in High-Renewable Systems*.

² BNEF (2026), *New Energy Outlook*.

³ Systemiq back-calculations based on the IEA's Stated Policies and Announced Pledges scenarios. IEA (2024), *The Future of Geothermal Energy*.

⁴ Conventional hydrothermal technologies refer to systems used to exploit subsurface hydrothermal reservoirs such as aquifers, where water trapped in porous or fractured rock beneath a layer of relatively impermeable caprock forms a reservoir and is heated by the surrounding rock. IEA (2024), *The Future of Geothermal Energy*.

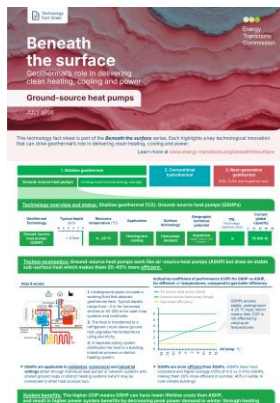
⁵ Next-generation refers to "reservoir-independent" approaches, currently in demonstration or early commercial deployment stages. The two main categories are enhanced geothermal systems (EGS) and closed-loop geothermal systems (CLGS; also called advanced geothermal systems [AGSs]). IEA (2024), *The Future of Geothermal Energy*.



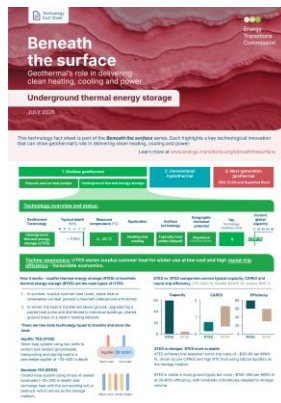
consent and the avoidance of sensitive sites can determine both how and whether a project proceeds.

#6 Each geothermal technology has different binding scale-up constraints across resource, financing, supply chains and technology readiness level. Effective policy means targeting the right intervention for the right technology in the right geography.

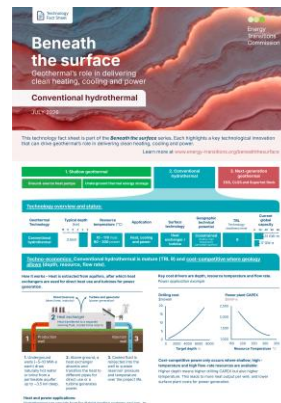
Technology Factsheets



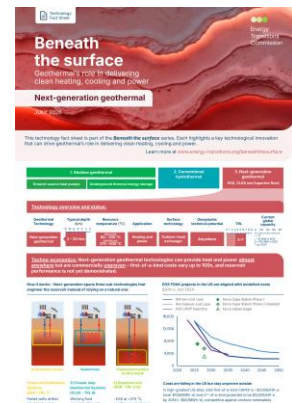
Ground-source heat pumps
Technology Fact Sheet



Underground thermal energy storage
Technology Fact Sheet



Conventional hydrothermal
Technology Fact Sheet



Next-generation geothermal
Technology Fact Sheet



1

Geothermal energy spans three distinct technology families with fundamentally different costs, maturities and geographical relevance – policymakers and investors should treat each on its own terms and potential.

Debates about geothermal energy's potential tend to treat it as a single technology. However, the three technology families covered in this Insights Briefing – shallow systems, conventional hydrothermal and deep next-generation systems – differ fundamentally in their costs, maturity, geographical reach and the energy services they can provide. Understanding which technology applies in which context is the starting point for sound policy and investment decisions.

All three technology families extract heat stored in rocks, soil and fluids beneath the earth's surface. The thermal energy captured can be used as heat directly or can be converted into power. Resource temperature determines whether heat or power is the main use case, and the value of the heat itself. Direct heat use is already possible at resource temperatures above 4°C via ground-source heat pumps, while conversion to power needs temperatures above 80°C and results in 70–90% of the energy being lost as heat. Local resource temperatures also define which geothermal technology can be used in different temperature gradients around the world.

We identify three main technology families:



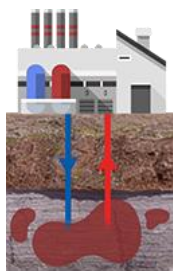
Shallow geothermal systems (heat)

Shallow geothermal systems capture or store 4–25°C heat, suitable for space and water heating and cooling.

Ground-source heat pumps (GSHPs, also referred to as geothermal heat pumps) at ~2–500 m depth provide heating and cooling for individual buildings and district heating networks – the wide range of depth reflects different piping systems.

Underground thermal energy storage (UTES, also referred to as geothermal storage) provides seasonal energy storage at ~20–500 m depth for individual (commercial) buildings and district heating networks. The main deployment barriers are financing and siting constraints.



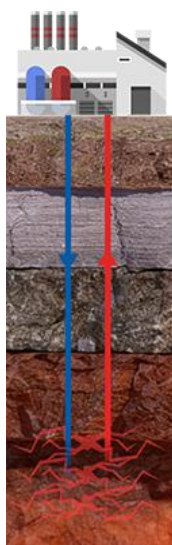


**50 – 300 °C
<3.5 km
depth**

Conventional hydrothermal systems (power and heat)

Conventional hydrothermal systems capture 50–300°C heat, typically at less than 3.5 km depth, which can be used for district or low- to medium-temperature (100–300°C) industrial process heat that is harder and costlier to electrify, district cooling through absorption chillers or power generation using turbines.

It requires all three conditions of high temperatures, natural permeability and water at drillable depth to be in place, which can only be confirmed during drilling. The main deployment barriers are resource availability, financial risk-sharing mechanisms and permitting.



**80 – 500 °C
2-20+ km
depth**

Next-generation systems (power and heat)

Next-generation systems capture 80–500°C heat at depths greater than 2 km, and include enhanced geothermal systems (EGS), closed-loop geothermal systems (CLGS) and superhot rock (SHR).

These systems can also be used for district heat, medium-grade industrial heat or power generation. Next-generation technologies, in contrast to conventional hydrothermal, require only sufficient temperature, which is far more predictable from regional gradient data.

The main deployment barriers are uncertainty around costs, lifetime technological performance at scale and immature regulatory and financing frameworks.

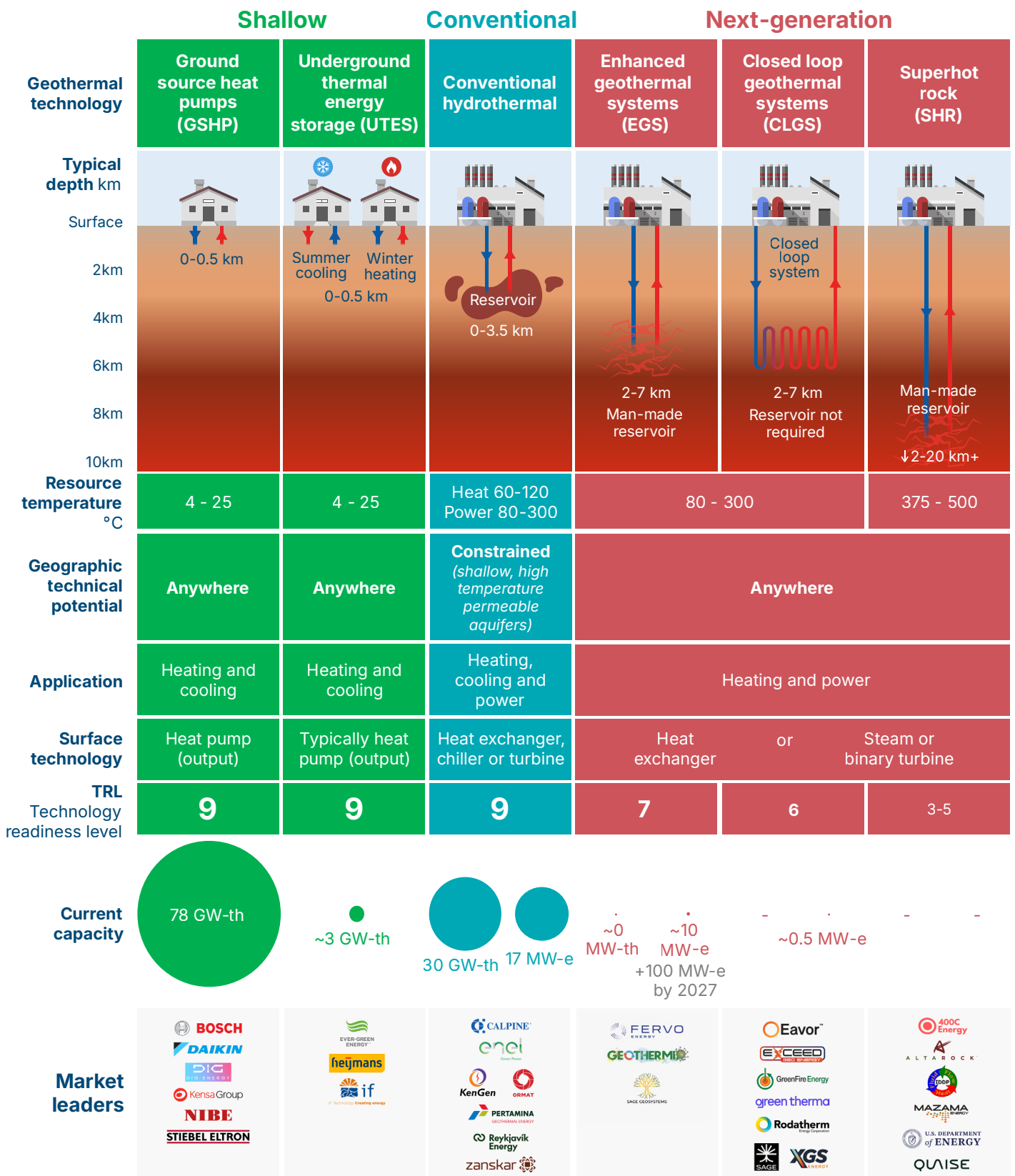
Each technology group has fundamentally different maturities, cost profiles, geographical resource availability and use cases [Exhibit 1]. They also have different deployment barriers, and with that require distinct policy and investment action to unlock scale: finance support, drilling de-risking and first-of-a-kind risk-sharing, respectively.

In this Insights Briefing, we discuss each technology group in turn, followed by a cross-cutting risk assessment and ending with policy recommendations.



Shallow geothermal, conventional hydrothermal, and next-generation technologies span a range of resource characteristics, applications, and maturities

EXHIBIT 1 **Characteristics of geothermal technologies 2026**



Note: Underground thermal energy storage parameters refer to aquifer and borehole thermal energy storage (excluding more nascent options such as geothermal mechanical storage). Steam turbines include flash, double flash, or binary Organic Rankine Cycle. Assumed TRL scale: TRL 1-3 = Research to Proof of Concept; TRL 4-6 = Lab to Pilot Demonstration; TRL 7-9 = Prototype Demonstration to FOAK / Full Commercial Deployment. GSHP capacity figure as of 2020. Underground thermal energy storage only includes aquifer thermal energy storage as most borehole systems today are not designed for seasonal use. 2.9 GW-th of ATEs supplies ~2.5 TWh-th of heating/cooling annually. Next-generation geothermal capacity is negligible globally; EGS <10 MWe operating (Fervo Cape Station Phase I ~100 MWe targeting late 2026), CLGS effectively zero net to grid today (Eavor Geretsried is partially operating at 0.5-1 MW-e gross, with remaining loops on hold), superhot rock is pre-pilot with no commercial projects. Heat deployment for next gen. is similarly nascent.

Source: Systemiq analysis for the ETC (2026); ETC (2025), Power Systems Transformation: Delivering Competitive, Resilient Electricity in High-Renewable Systems; NESO (2022), Future Energy Scenarios 2022 (FES 2022); Brown C.S. (2024), Assessing the technical potential for underground thermal energy storage in the UK.



Shallow geothermal technology has a high potential to scale, especially ground-source heat pumps (GSHP) and underground thermal energy storage (UTES), but is currently under-deployed. The barriers are finance and siting.

Shallow geothermal encompasses ground-source heat pumps (GSHPs) and underground thermal energy storage (UTES). GSHPs provide heating and cooling for buildings⁶ and UTES provides seasonal heat storage for heat networks – neither provides power. Three linked objectives define the role of shallow geothermal GSHPs and UTES in an electrifying economy:

- **Getting buildings off gas with heat pumps:** Electrification is the primary route to decarbonise building heat, largely through heat pumps which will be the main heat-decarbonisation technology for most buildings, due to their high efficiency and lower running costs.⁷ Air-source heat pumps (ASHPs) are the most scalable and affordable for most buildings. GSHPs are one heat pump option alongside ASHPs, but offer higher efficiency, especially in cold climates. GSHPs have high scalability when deployed in large commercial or residential buildings or at street- or network-level – improving practical deliverability, economies of scale.
- **Delivering cooling to help meet rising cooling demand:** Reversible GSHPs provide active space cooling, and UTES can store and supply "free" cooling (direct circulation without a compressor) – a co-benefit that grows in value as cooling needs increase in a warming climate with rising heatwave frequency around the world.⁸
- **Managing winter (heating) and summer (cooling) power demand peaks:**⁹ Electrifying heating and cooling shifts demand onto the power system, particularly during winter in cold climates and adding to the summer peak in warmer ones. Demand-side flexibility can shift heat-pump demand away from peak hours for both ASHPs and GSHPs;¹⁰ on top of this, the higher efficiency of GSHPs lowers peak power intensity by up to ~40% for heating and ~30% for cooling compared to ASHPs.¹¹ Seasonal UTES adds a further lever, storing surplus summer heat for winter and, in

⁶ GSHP could play a role in decarbonising low temperature heat in industry too – but the main opportunity sits in residential and commercial buildings.

⁷ ETC (2025), *Achieving Zero-Carbon Buildings: Electric, Efficient and Flexible*.

⁸ Emerton E. (2026), *Global heat stress intensification and its expanding footprint on the human population*.

⁹ For system-balancing and peak-demand context, see ETC (2025), *Power Systems Transformation: Delivering Competitive, Resilient Electricity in High-Renewable Systems*.

¹⁰ ETC (2025), *Demand side flexibility – unleashing untapped potential for clean power*.

¹¹ US DoE (2025), *Pathways to Commercial Liftoff: Geothermal Heating and Cooling*.



bidirectional systems (ATES), winter cold for summer cooling – together easing power-system adequacy and grid-investment needs.

High adoption of GSHPs could increase deployment by 4–6x to 20–40 million units globally by 2050¹². In suitable markets where peak power system capacity requirements are increasingly driven by heating in winter (e.g., Northern Europe) or cooling in summer (e.g., Southern US), the higher efficiency of GSHP means lower peak power capacity and grid buildout will be needed. In the US, this can reduce required power generation capacity by about 10% and transmission capacity by 20% compared to electrification pathways with no GSHP deployment, saving consumers \$77 billion per year.¹³ Seasonal UTES could meet ~10% of annual heat demand in seasonal systems, cutting peak winter electricity demand and system costs by ~5%.¹⁴

Shallow geothermal is the most deployable of the three technology families: it works in almost any geography, the technology is mature, and the economics are sound. Yet it is currently under-deployed and GSHPs currently only meet ~0.3% of global final heat consumption through ~160 TWh-th per year.¹⁵ The barrier to scale is not technology or lifetime cost – it is the high upfront capital investment and siting limitations due to their horizontal or vertical piping system.



As GSHPs and UTES have different working principles, techno-economics and policy priorities, we outline each separately below.

2.1 Ground-source heat pumps can replace gas boilers with electric heating drawn from stable subsurface heat. They can have lower lifetime costs and higher system benefits than air-source heat pumps (ASHPs) driven by their high efficiency, especially in cold climates and where they can be integrated into district heating networks. Yet deployment lags due to their higher upfront capital expenditure (CAPEX) and more complex installation and siting limitations than ASHP which limits uptake in the existing housing stock.

- **GSHPs work like ASHPs but use stable subsurface heat, making them 20–40% more efficient, especially in winter in cold climates.** GSHPs typically access stable, 4–25°C (typically 10–15°C) underground temperatures throughout the year, while the air temperature used in ASHPs varies between winter and summer. Heat is exchanged at depths of up to 500 m via a working fluid and refrigerant evaporation/compression cycle. This means the coefficient of performance (COP – a ratio of power use efficiency to upgraded heat)¹⁶ of GSHPs is consistent and higher at between 3–

¹² Systemiq analysis for the ETC based on BNEF (2026), *New Energy Outlook*.

¹³ US DoE (2025), *Pathways to Commercial Liftoff: Geothermal Heating and Cooling*; Oak Ridge National Laboratory (2023), *Grid Cost and Total Emissions Reductions Through Mass Deployment of Geothermal Heat Pumps for Building Heating and Cooling Electrification in the United States*.

¹⁴ Systemiq analysis for the ETC (2026); ETC (2025), *Power Systems Transformation: Delivering Competitive, Resilient Electricity in High-Renewable Systems*.

¹⁵ Systemiq back-calculations based on the IEA's Stated Policies and Announced Pledges scenarios. IEA (2024), *The Future of Geothermal Energy*.

¹⁶ COP is a measure of efficiency, meaning the ratio of useful heating or cooling output (in kW-th) to electricity input (kW-e). An alternative measure is Seasonal Performance Factor (SPF) which is assessed over the course of a year, reflecting the average efficiencies for heat pumps over time in a specific location/climate.



6 throughout the year, while ASHPs vary between ~1.5–4.5 – declining as air temperature decreases and the required temperature lift increases. The COP advantage of GSHPs compared to ASHPs is most pronounced in extreme cold and hot temperatures. [Exhibit 2] The relatively high COP of GSHPs means that the peak power input intensity in cold-climate buildings is ~20–40% lower for heating in winter peak.¹⁷ The GSHP cycle is reversible: the same unit draws heat from the ground in winter and rejects it in summer, delivering active cooling at materially lower, 15–30% lower peak power intensity than ASHPs.¹⁷ In systems where heat dominates demand, the summer reversal also helps recharge underground temperatures to maintain long-term efficiency.

- GSHPs can have lower lifetime costs than ASHP driven by higher efficiency, despite higher CAPEX. CAPEX is higher due to the need for ground works to install the GSHP. Yet lifetime costs can be lower due to their lower operating expenses (OPEX) – specifically in cold climates. The impact of economies of scale means large-scale applications of GSHPs in e.g., district heat networks, industry or for large commercial or residential users are particularly competitive relative to ASHPs. Additional cost drivers differ by case:
 - Installation costs and power prices differ geographically;
 - Larger heat pump unit sizes lower CAPEX through economies of scale;
 - Whether it's a new build or retrofit building impacts ground works hence CAPEX; and
 - A shared ground loop spreads the groundworks CAPEX over multiple buildings, decreasing the cost per unit.¹⁸

¹⁷ US DoE (2025), *Pathways to Commercial Liftoff: Geothermal Heating and Cooling*.

¹⁸ Element Energy for The Kensa Group (2023), *Low Carbon Heat Study – Phase 1*.



The high coefficient of performance of ground-source heat pumps means they can have competitive lifetime costs given low running costs

EXHIBIT 2A COP vs. outdoor temperature for air-source heat pumps (ASHP) and (GSHP)

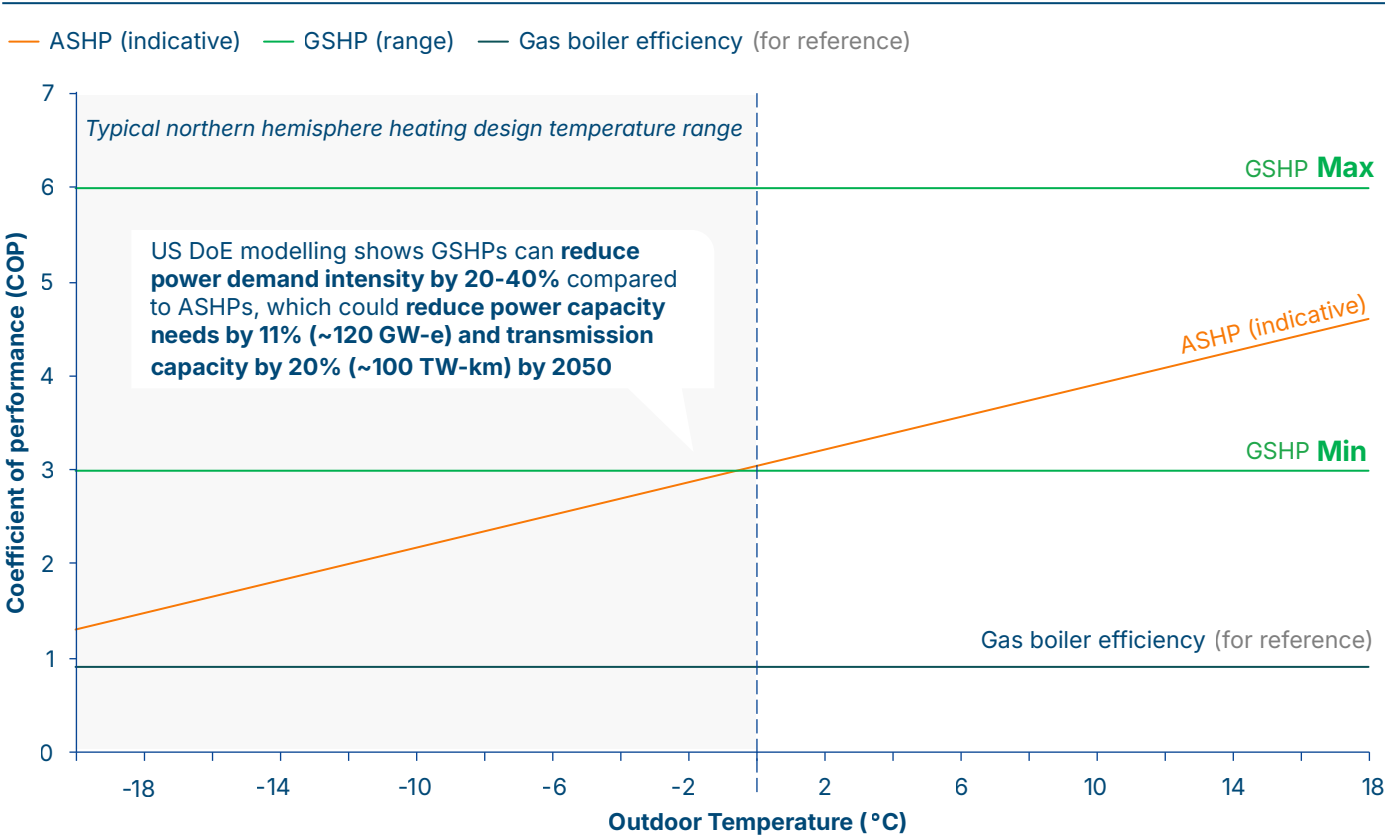
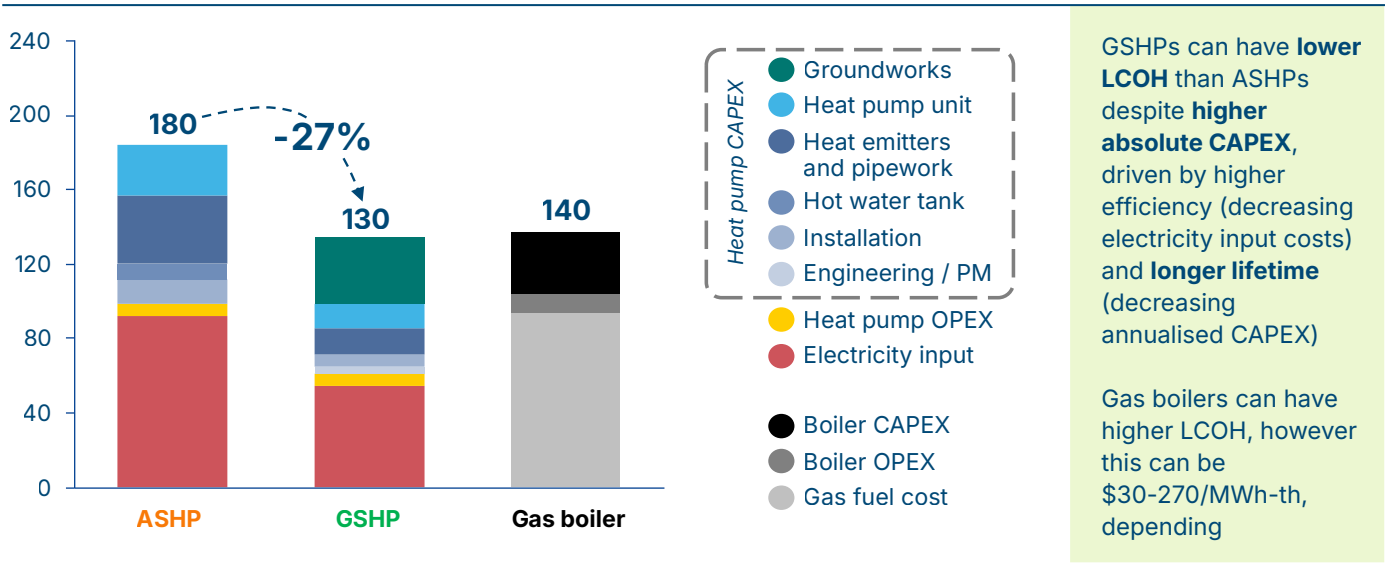


EXHIBIT 2B LCOH breakdown for ASHP, GSHP and gas boiler (UK retrofit example)

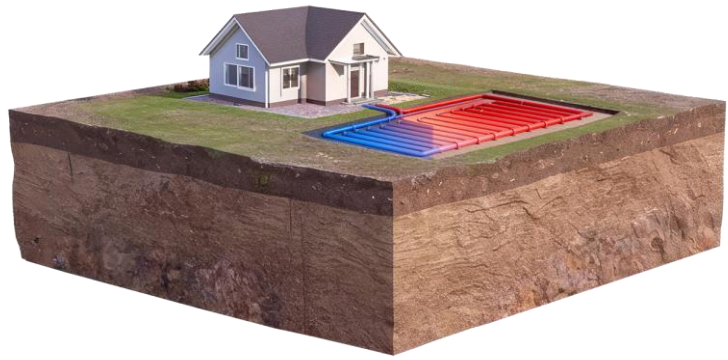


Notes: LCOH = Levelised cost of heat; ASHPs are sized at ~6 kW (55°C flow) for the Victorian terrace retrofit; GSHPs use Kensa Evo 7 COP curves with one borehole per dwelling (216 m retrofit) in typical UK ground conditions, reflecting modelled annual heat demands of 13.9 MWh per year and 5.6 MWh per year respectively (back-calculated from gas demand using a boiler efficiency of 90%). Element Energy assumptions include OPEX: £60 per year for both technologies. Fuel: 2020 baseline electricity tariffs, hourly COP-weighted. Lifetimes: ASHP 15 years, GSHP heat pump 25 years, groundworks 100 years. Gas boiler LCOH assumes £3,000 installed CAPEX over a 12-year life, 12 MWh-th annual demand at 90% efficiency, 6.5p per kWh of gas, and a 3.5% real discount rate.

Sources: Systemiq analysis for the ETC (2026), Garcia-Cascales, M. (2020) Spatial assessment of the Ground Source Heat Pumps suitability against conventional heat pumps based on Superficial Air Temperature; The Engineering Toolbox (2025) Heat Pumps - Performance and Efficiency Ratings; Element Energy for The Kensa Group (2023), Low Carbon Heat Study – Phase 1; Department for Energy Security and Net Zero (2025), Quarterly Energy Prices



- **GSHP deployment at scale can have higher system benefits than ASHPs in systems with high heating or cooling demand: Their high COP means they reduce peak power demand and drive efficient grid buildout.** The higher efficiency of GSHP means less peak power capacity is needed for heating in winter (driving annual



peak demand in e.g., Northern Europe) and cooling in summer (driving annual peak demand in e.g., Southern US), and with that lower overall grid capacity is required. US Department of Energy (DoE) modelling shows high GSHP adoption (reaching around 15% of residential and 5% of commercial buildings) could reduce power capacity needs by ~10% by 2050 (~120 GW-e) and transmission capacity by 20% (~100 TW-km). This could result in \$77 billion per year consumer savings by 2050, compared to low-GSHP electrification scenarios.¹⁹ This principle can be applied across many temperate regions to maximise the energy services delivered to consumers in expanding power systems. When individual GSHP systems are connected to a shared underground loop (through thermal energy networks), buildings requiring heating and those requiring cooling can exchange thermal loads directly, improving system efficiency. Gas utilities in multiple markets are piloting thermal energy networks as a pathway to replace gas distribution lines.²⁰

- **Despite their benefits, GSHPs are only 10% of total heat pump capacity worldwide.** There were about ~6.5 million GSHP units installed in 2020 in North America, China and Europe (~78 GW), together supplying ~70% of total geothermal heat delivered today.²¹ The vast majority of GSHP installations are in residential and commercial buildings. Around two-thirds of global capacity is in China, where GSHPs are built into new developments and shared district networks across some 841 million m² of buildings.²² GSHPs make up less than 10% of total heat pump capacity, with ASHPs making up ~920 GW-th.²³ This discrepancy can be explained by the relatively high upfront costs as well as the fact that ASHPs require less space, so are more suitable for much of the existing and urban house stock.

GSHPs have significant system benefits relative to gas-based heating and ASHPs – policymakers should act to unlock scale. GSHPs should be prioritised over fossil incumbent technologies and air-source heat pumps where they can be deployed at scale, especially in colder climates. They are specifically relevant for district heating networks and industrial applications due to impact of economics of scale on delivered heating and cooling costs, potential integration with UTES and typically less installation or siting constraints. Capturing their potential requires policy that addresses the upfront cost

¹⁹ US DoE (2025), *Pathways to Commercial Liftoff: Geothermal Heating and Cooling*; Oak Ridge National Laboratory (2023), *Grid Cost and Total Emissions Reductions Through Mass Deployment of Geothermal Heat Pumps for Building Heating and Cooling Electrification in the United States*.

²⁰ Eversource (n.d.) *Our First-of-its-Kind Pilot Uses Utility-Scale, Networked Geothermal*. Available at: <<https://www.eversource.com/residential/save-money-energy/clean-energy-options/geothermal-energy/geothermal-pilot-framingham>> [Accessed June 2026].

²¹ Kearney Energy Transition Institute (2025), *Geothermal Energy, Turning Up the Heat*.

²² J. Zhao (2021), *Application and development of ground source heat pump technology in China*.

²³ Assuming 12 kW per GSHP; this is under 10% of total heat pump capacity worldwide, with air source heat pumps making up ~920 GW-th in 2021 and potentially rising to 2,600 by 2030. J. Lund (2020), *Direct Utilization of Geothermal Energy 2020 Worldwide Review*; H. Maghrabie (2023), *Ground-source heat pumps (GSHPs): Materials, models, applications, and sustainability*; IEA (2021), *The Future of Heat Pumps*.



barrier through e.g., targeted capital subsidies (for industrial applications) and/or building-code mandates for new-builds.

2.2 Underground thermal energy storage (UTES) is a seasonal storage technology. It captures surplus heat in summer (typically charged to <25°C)²⁴ and cold in winter and stores it underground, typically in aquifers or boreholes, for release as heating in winter or cooling in summer at low cost and high round-trip efficiency. This provides strong system value in increasingly wind power-dominated, seasonal-demand markets where long duration storage – either fossil- or low-carbon gas-based – will be required to cover sustained lulls in renewable energy output. Although the technology is mature, its role is emerging: seasonal heat storage becomes specifically valuable once a system has electrified heat and runs on high shares of variable renewables. UTES could provide seasonal balancing at 2–8x lower cost than the low-utilisation fossil or low-carbon gas assets it would replace. Yet deployment remains marginal today, held back by institutional rather than geological barriers:

- **UTES is a family of technologies that stores surplus summer heat that can be used in winter.** They collect summer heat (from solar collectors, renewables via heat pumps or industrial waste heat) and store this underground in either groundwater aquifers or in boreholes.
 - Aquifer thermal energy storage (ATES) uses open-loop paired wells to store heat in a permeable aquifer at 20–500 m of depth. ATES is operated bidirectionally: it can store summer heat for winter use as well as winter cold for summer use. The latter is considered "free cooling", as it's done via direct heat exchange without a compressor (the only meaningful electricity draw is groundwater pumping), and is therefore among the lowest-energy cooling inputs available. Modelled system COP for ATES cooling reach ~40 – about four times those of equivalent open-loop systems without storage (~10) – and far above conventional electric chillers.²⁵
 - Borehole thermal energy storage (BTES) uses arrays of closed-loop 30–200 m boreholes to store thermal energy in the soil or bedrock itself.²⁶
 - UTES are typically connected to district heating networks or large buildings (individually or in clusters) to improve economics.
- **Installed capacity is limited today.** There are around ~3,000 active (ATES) sites globally – 85% of which are in the Netherlands.²⁷ The total 2.9 GW-th of installed ATES charge/discharge capacity delivers ~2.5 TWh of heating and cooling per year, reflecting seasonal cycling utilisation rates of ~10%.²⁸ Most operational ATES schemes, therefore, serve combined heating and cooling loads. BTES configured for seasonal storage is currently more limited, with only a handful of demonstration projects globally.²⁹

²⁴ Low-temperature UTES systems <25 °C are most common, and injection temperatures are typically regulated to less than 25°C for environmental reasons, however. However, high-temperature ATES up to ~85 °C has been demonstrated in the Netherlands. M. Herrmann (2025), *Capital costs of aquifer thermal energy storage (ATES): a review*.

²⁵ Modelled UK Monte-Carlo values for balanced, well-operated systems supplying direct cooling without a heat pump; achieved performance in operating systems is lower. Jackson, M.D. (2024), *Aquifer Thermal Energy Storage for low carbon heating and cooling in the United Kingdom: Current status and future prospects*.

²⁶ Mine thermal energy storage (MTES) – storing heat in flooded abandoned mine workings where present – is a further open-loop UTES option operating on the same seasonal store-and-reuse principle. M. Herrmann (2025), *Capital costs of aquifer thermal energy storage (ATES): a review*; IEA (2024), *The Future of Geothermal Energy*.

²⁷ Kearney Energy Transition Institute (2025), *Geothermal Energy, Turning Up the Heat*.

²⁸ Fleuchaus et al. (2018), *Worldwide application of aquifer thermal energy storage – A review*.

²⁹ The 1 million BTES systems worldwide reflect closed-loop GSHP borefields that exchange heat with the natural ground temperature, very few currently actively store seasonal thermal energy. F. Guo (2020), *Large-scale living laboratory of seasonal borehole thermal energy storage system for urban district heating*; *Renewable and Sustainable Energy Reviews*, 94: 861–876; P. Fleuchaus (2018), *Worldwide application of aquifer thermal energy storage – A review*. Available at: <https://doi.org/10.1016/j.rser.2018.06.057> [assessed 05 2026]



- Aquifer TES offers a cheaper route to clean seasonal energy storage than alternatives due to high efficiency and low CAPEX, whereas Borehole TES is more scalable but at higher costs and lower efficiency:**³⁰ ATES achieves low estimated seasonal levelised cost of heat (LCOH) of ~\$30–90 per MWh-th (assuming one cycle per year), due to low construction costs to access naturally occurring aquifers and high round-trip efficiency of 60–80%.³¹ BTES is more scalable as it is viable in most ground types (where aquifers are absent), but it has a higher estimated LCOH of ~\$140–260 per MWh-th, due to the hundreds of boreholes required to create sufficient storage volume and lower efficiency of 30–60%.³² ATES could be 2–6x cheaper per unit of heat delivered by heat pumps via seasonal energy storage from a new natural gas peaking plant at ~\$170 per MWh-th, 3–8x cheaper than clean alternatives such as green hydrogen at ~\$250 per MWh-th, and 2–5x cheaper than heat delivered by new natural gas boilers. This is driven by ATES's low CAPEX and high efficiency, against alternatives with higher CAPEX spread over very few cycles per year – compounded by low efficiency for green hydrogen.³³
- UTES can create high system value by reducing firm/back-up power needs – especially in wind-dominated systems. [Exhibit 3]** As the share of renewables in power systems increases and heat electrifies, the relevance of seasonal storage increases. In the UK, a “windbelt” country, 20 TWh-th of seasonal UTES, offsetting ~5% of annual power demand for heat in 2050, could cut peak winter power demand by over 10% and save up to \$5 per MWh-e in system costs compared to relying on natural gas or alternative seasonal storage options. Solar-dominated systems in the global “sunbelt” will typically be less seasonal, meaning that the benefits of seasonal storage are lower.³⁴

³⁰ Throughout this report, thermal capacity and energy units are identified using “-th” (e.g., kW-th and MWh-th) and electrical capacity and energy units are identified using “-e” (e.g., kW-e and MWh-e).

³¹ Achieved efficiency is geology-dependent, with homogeneous sands (e.g., in the Netherlands) at the upper end and fractured, heterogeneous aquifers (e.g., UK Chalk and Sherwood Sandstone) recovering materially less, placing real-world performance toward the lower end of this range Jackson, M.D. (2024), *Aquifer Thermal Energy Storage for low carbon heating and cooling in the United Kingdom: Current status and future prospects*.

³² M. Janiszewski (2019), *Techno-economic aspects of seasonal underground storage of solar thermal energy in hard crystalline rocks*; M. Herrmann (2025), *Capital costs of aquifer thermal energy storage (ATES): a review*.

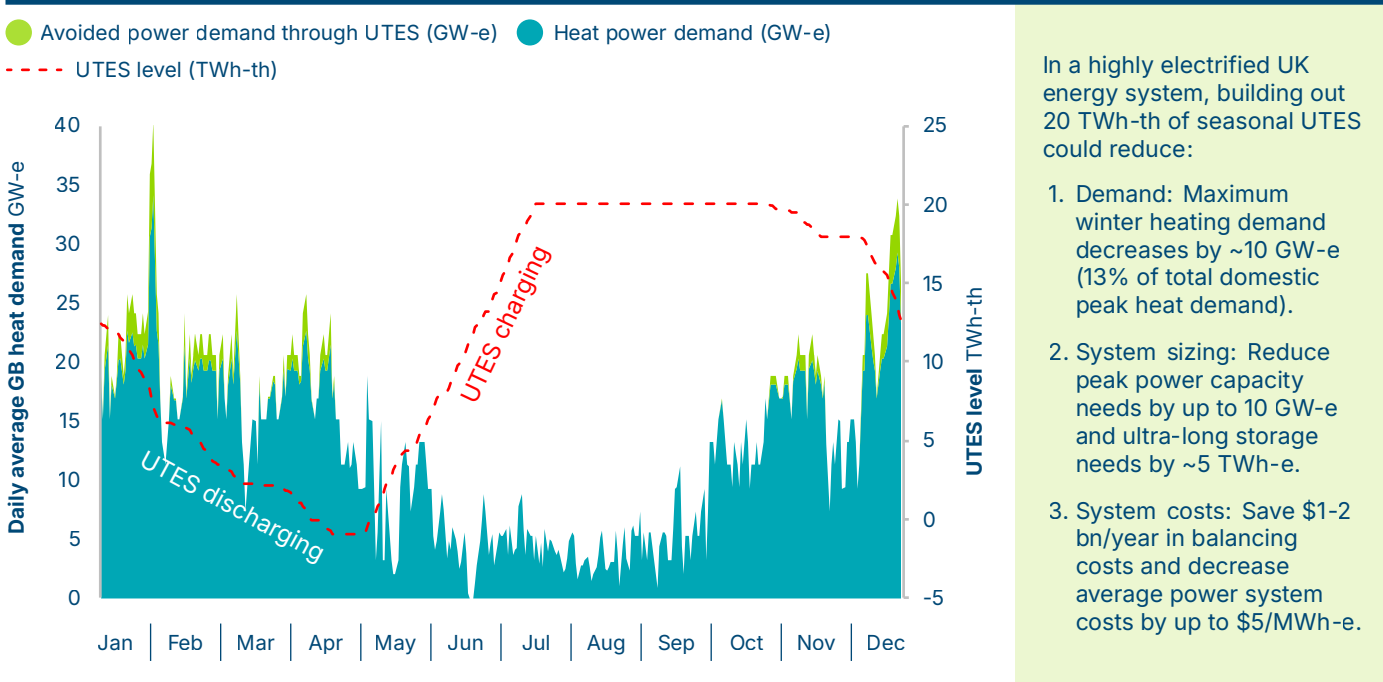
³³ Systemiq analysis for the ETC (2026), Seasonal storage economics assume 1.5% utilisation: new natural gas peaker LCOE estimated to be ~\$520 per MWh-e (or ~\$170 per MWh-th if reconverted to heat via heat pumps with COP 3) and green hydrogen LCOS estimated to be ~\$740 per MWh-e (or ~\$250 per MWh-th reconverted). Assumptions are aligned with Exhibit 1.42 in ETC (2025), *Power Systems Transformation: Delivering Competitive, Resilient Electricity in High-Renewable Systems*.

³⁴ Systemiq analysis for the ETC (2026); ETC (2025), *Power Systems Transformation: Delivering Competitive, Resilient Electricity in High-Renewable Systems*; NESO (2022), *Future Energy Scenarios 2022 (FES 2022)*; Brown C.S. (2024), *Assessing the technical potential for underground thermal energy storage in the UK*.



Underground thermal energy storage (UTES) can materially decrease seasonal demand peaks, system sizing and total system costs if deployed at scale

EXHIBIT 3 **Hypothetical underground TES impact on Great Britain (GB) 2050 clean electrified heating demand** Daily average GB heat demand GW-e; TES level – TWh-th



Note: 20 TWh-th of storage is 13% of the UK's 2050 annual heat demand. 70% round-trip efficiency and 6% real WACC assumed, alongside average heat-pump COPs of 3 in winter and 4 in summer. UTES is charged May–September from excess renewables. Discharge is optimised for peak-shaving: the store discharges whenever national heating demand exceeds 30 GW-e, at up to 10 GW-e, cutting maximum winter demand by 10 GW-e (75 → 65 GW-e) across ~840 hours while cycling ~75% of the store (within its physical capacity). Peak reduction is limited by discharge power, not stored energy; demand-side flexibility would reduce the residual peak further. Demand is modelled for one weather year, therefore a wide range of variations is not accounted for. System cost savings span energy value through avoided ultra-long electricity storage (\$400/MWh-e assumed) and peaker capacity cost (\$50/kW-e/year assumed), net of additional UTES levelised cost of thermal storage. System cost impact range calculated using 7 GW-e discharge as the lower bound.

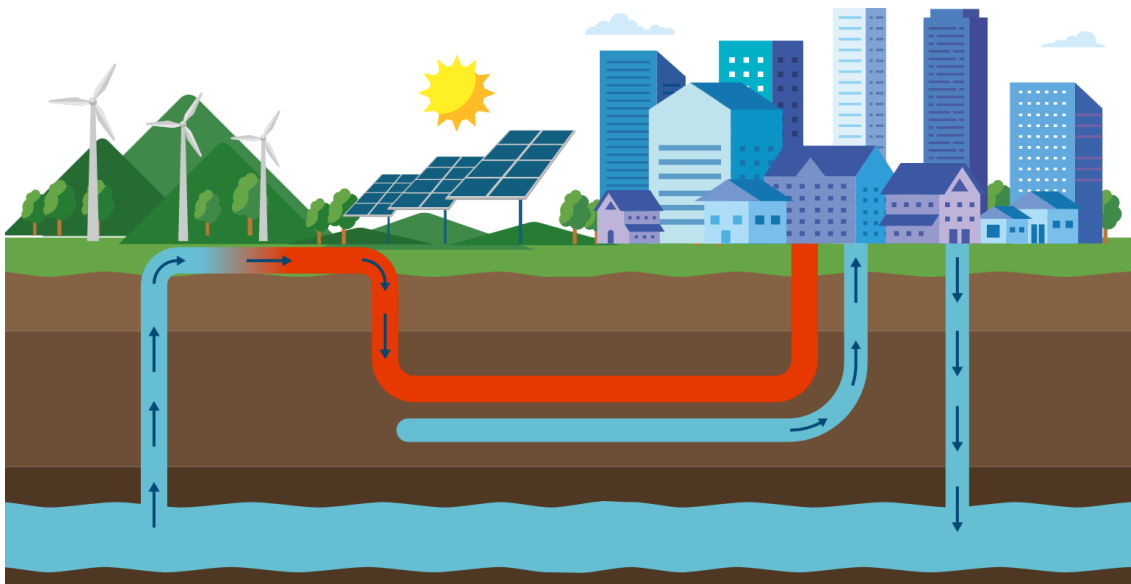
Source: Systemiq analysis for the ETC (2026); ETC (2025), Power Systems Transformation: Delivering Competitive, Resilient Electricity in High-Renewable Systems; NESO (2022), Future Energy Scenarios 2022 (FES 2022); Brown C.S. (2024), Assessing the technical potential for underground thermal energy storage in the UK.



- **Regulatory barriers are holding UTES potential back:** UTES is often indistinguishable from non-storage open-loop systems in regulatory databases, lacks dedicated permitting policy and a domestic installer base, and is largely absent from national heat strategies. These barriers are, therefore, addressable through policy and regulation.

UTES offer a much cheaper and technically unconstrained alternative for seasonal storage than many clean alternatives – policymakers should address financing and roll-out barriers to unlock scale.

Markets most suited to UTES buildout are high-latitude “windbelt” systems, with rising seasonal balancing challenges as the share of wind in electricity generation increases, and countries with existing or planned heat networks. Suitable hydrogeology (for ATES) is unevenly distributed, high upfront costs deter developers, and the district-heating infrastructure needed to anchor projects is absent in most markets. Enabling UTES potential, therefore, requires policies that address subsurface permitting barriers, de-risk project finance for long-duration storage, support development of a domestic installer base and embed seasonal UTES into district-heating planning.



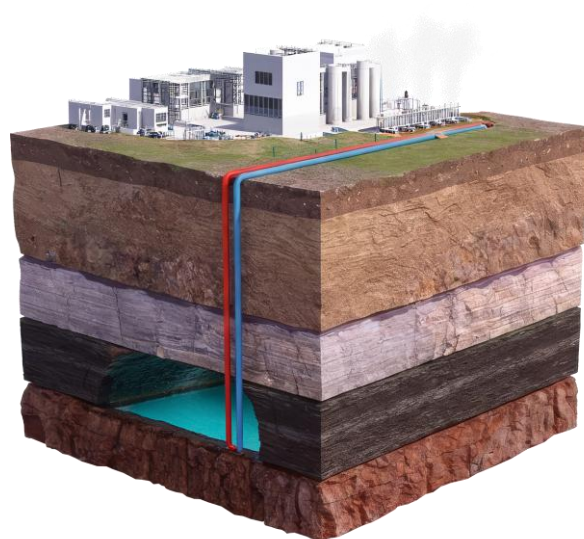
Aquifer thermal energy storage (ATES) uses naturally occurring underground water to store thermal energy over seasons to heat and cool buildings.



3

Conventional hydrothermal is mature and cost-competitive where geology allows, but geological constraints will keep its contribution below 1% of global heat consumption and power generation in 2050, with an emerging role in cooling.

Conventional hydrothermal is relevant for three energy system needs: it can displace gas for district and industrial heat, provide district-scale cooling and providing firm, dispatchable clean power using steam or binary turbines, to complement variable renewables. Its application is bound to places where naturally hot, permeable aquifers exist, but is mature and cost-competitive where such a resource is present. It currently meets ~0.2% (~140 TWh-th) of global final heat consumption and 0.3% of global electricity (~100 TWh-e).³⁵ The binding constraint for further scale is, therefore, geology and exploration risk rather than cost.



Heat is set to remain the broader role of the three roles, with direct-use potentially increasing 3–5x to 400–700 TWh-th per year by 2050, meeting up to 1% of global final heat consumption.³⁶ It typically needs at least 40°C resource, and district heating is the dominant application, which typically uses 90–140°C heat.³⁷ This level is available across far more geographies, avoids the 70–90% conversion losses resulting from power generation, and can plug into existing district heating networks. Geothermal cooling from hydrothermal resources is an emerging, not-yet-quantified geothermal application which could meet rising cooling demand globally. Geothermal power capacity can increase by 1.5–4x but is expected to remain under 80 GW-e (up to 1% of global electricity generation).³⁸ Power generation needs hotter, permeable reservoirs found only in volcanic or tectonically active regions, limiting its potential.

- **Conventional hydrothermal is a mature technology that draws water from hot, permeable aquifers at depths of typically less than 3.5 km.** The water temperature largely varies by depth (ranging from

³⁵ 70% of direct-heat use (excluding GSHPs) is through district heating and the remainder in direct space and water heating, bathing, agriculture and fishing, and industry. IEA (2024), *The Future of Geothermal Energy*

³⁶ Systemiq back-calculations based on the IEA's Stated Policies and Announced Pledges scenarios. IEA (2024), *The Future of Geothermal Energy*.

³⁷ Temperatures as low as 10 °C can be used in aquaculture. Combined heat and power systems or "co-generation" can also make use of lower-temperature working fluids when collocated with geothermal electricity-generation cycles. Kearney Energy Transition Institute (2025), *Geothermal Energy, Turning Up the Heat*.

³⁸ Systemiq back-calculations based on the IEA's Stated Policies and Announced Pledges scenarios, assuming an average capacity factor of 85%. IEA (2024), *The Future of Geothermal Energy*



~0.2–3.5 km),³⁹ and accessible depths and temperatures vary by location globally. These reservoirs fall into two settings: fault and fracture-hosted convective systems in volcanic or tectonically active regions, which can be used for heat or power and hot sedimentary aquifers (HSA), where heat from the regional geothermal gradient accumulates in deep permeable sedimentary formations. The water needs to be at least 50°C to use it for heat consumption directly (or ~60°C via heat exchangers) but needs temperatures of >180°C to generate electricity via steam turbines or >80°C for binary Organic Rankine Cycle (ORC) turbines for low temperatures.⁴⁰ The aquifer also needs to have high permeability – meaning fluid can easily move through. It's a mature technology that has been at technology readiness level (TRL) 9 since the early 20th century. The mechanism is essentially unchanged. Gains over the past century have come from better drilling, reservoir management and binary cycles for lower-temperature resources.⁴¹

- **Installed capacity today is highly geographically concentrated – driven by geological requirements to deploy [Exhibit 4].** The specific temperatures, depth and high permeability requirements constrain conventional hydrothermal to a limited number of regions. There is currently ~30 GW-th of direct heat use capacity producing ~140 TWh-th per year (~0.2% of global heat demand). Most of this is heat used in district heating networks (~70% of conventional hydrothermal heat output), and 60% of capacity is concentrated in four countries: the US, Türkiye, Iceland and Japan. Power capacity is currently ~17 GW-e, generating ~100 TWh-e per year (~0.3% of global electricity generation) and is concentrated in the US, Indonesia, the Philippines and Türkiye. Around 4% of power plants are also configured for heat output.⁴²



³⁹ Kearney Energy Transition Institute (2025), *Geothermal Energy, Turning Up the Heat*.

⁴⁰ Either binary Organic Rankine Cycle for ~80–200°C or single / double flash for 180–300°C. In an Organic Rankine Cycle, a low-boiling-point organic fluid (e.g., isobutane or pentane) is vaporized by geothermal heat, drives a turbine, and is condensed and recycled (subcritical operates below critical pressure and supercritical operates at a supercritical pressure). A single flash steam system is where high-pressure geothermal water from the reservoir is depressurised ("flashed") to produce steam that drives a turbine. In a double flash system, after the first flash and turbine stage, the remaining liquid is flashed again at lower pressure, increasing energy extraction by about 15–25%. Source: Koenraad F. Beckers (2019), *GEOPHIRES v2.0: Updated Geothermal Techno-economic Simulation Tool*.

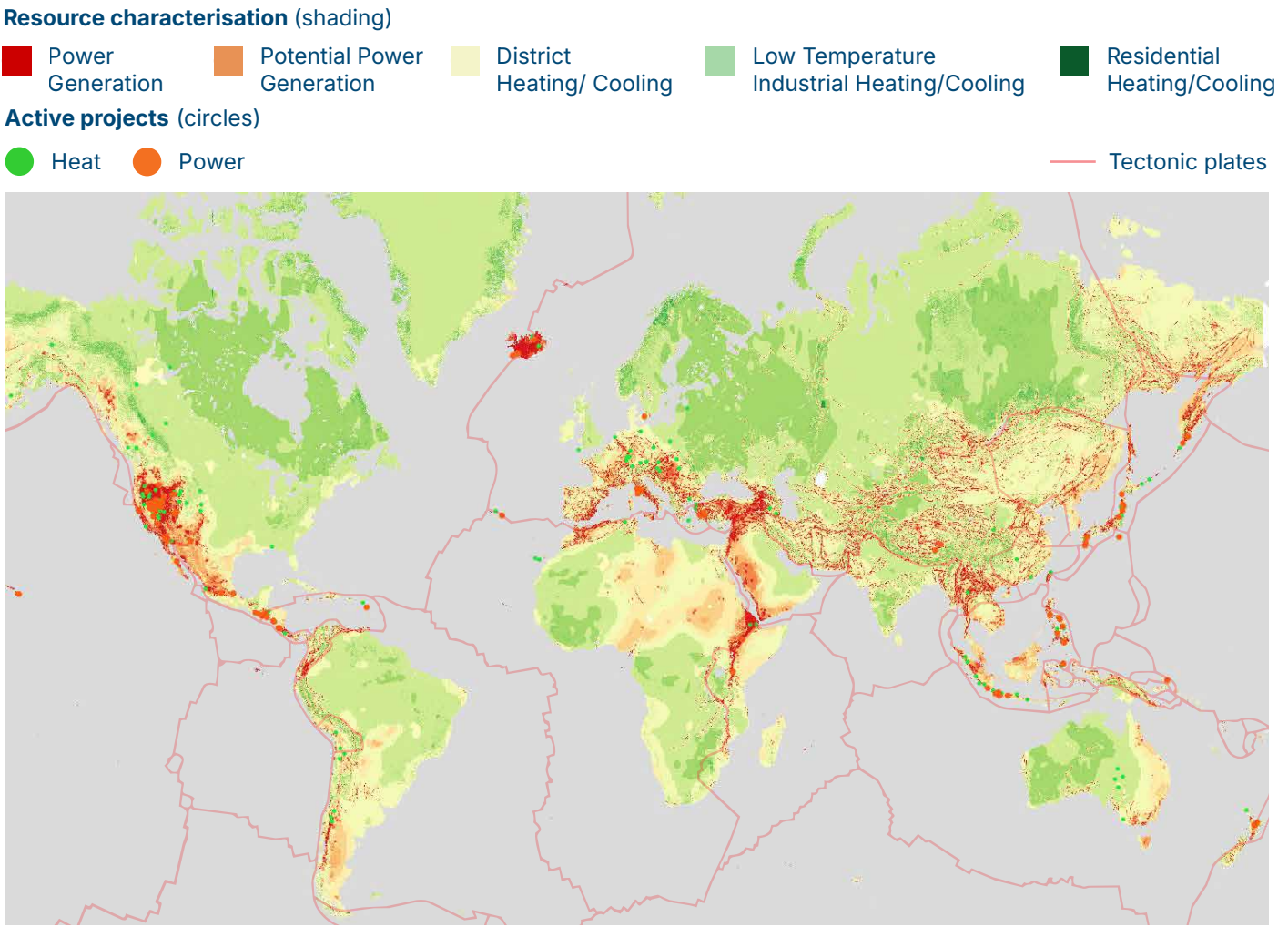
⁴¹ Kearney Energy Transition Institute (2025), *Geothermal Energy, Turning Up the Heat*.

⁴² IEA (2024), *The Future of Geothermal Energy*.



Conventional hydrothermal power potential is concentrated in tectonically active regions; district, residential and low-temperature industry heating/cooling potential is ubiquitous

EXHIBIT 4 **Global resource characterisation for power, heating and cooling**
(Project Innerspace)



Note: Resource characterisation uses Project InnerSpace's Subsurface Favourability Map, developed through a Weighted Overlay Analysis, a Geographic Information System -based technique that integrates multiple spatial data layers while assigning varying weights based on their relevance and significance for a specific objective. Source: Project InnerSpace (2025), GeoMap Beta; Coro et al. (2020), Predicting Geographical Suitability of Geothermal Power Plants; World Resources Institute (2019), A Global Database of Power Plants; National Geographic (n.d.) Mapmaker, Plate Boundaries. Available at <<https://www.arcgis.com/apps/instant/atlas/index.html>> [Accessed 07 2026].



- **The lifetime costs of direct-heat use and power generation are competitive with alternatives in viable locations, but vary geographically.** CAPEX for direct-heat use is ~30–50% lower than those for power generation due to the avoidance of an electricity generation plant.⁴³ The typical levelised cost of heat (LCOH) is \$20–110 per MWh-th in locations with suitable geological settings.⁴⁴ This is competitive against European gas, which has been highly volatile since 2022, when it exceeded \$200 per MWh-th then since settled to a ~\$50 per MWh-th baseline (compared to a pre-2022 norm of ~\$20–25 per MWh-th).⁴⁵ But this LCOH remains uncompetitive against US gas at ~\$10 per MWh-th.⁴⁶ For power use, the global average levelised cost of electricity (LCOE) in 2025 was ~\$90 per MWh, which has increased from ~\$60 per MWh-e since 2010.⁴⁷ This LCOE range is comparable to nuclear and large-scale hydropower, and at the lower end of the range competitive with hybrid 24/7 renewable configurations (solar, wind and storage), which are expected to deliver firm power at \$80–120 per MWh in favourable locations. [Exhibit 5]
- **Key cost drivers are the same for conventional heat and power – drilling depth, resource temperature, permeability and flow rates and weighted average cost of capital (WACC) – with distance to end users adding a further driver for heat.** CAPEX dominates levelised costs, at ~80% of lifetime cost for power, and varies by 5x across sites (typically \$1,200–6,000 per kW-e for power).⁴⁸ This range is determined by site characteristics – reservoir depth and temperature, permeability, flow rates and achievable utilisation – and compounded by local drilling costs, supply-chain maturity and project scale. Deeper, hotter resources raise per-well output and lower surface-plant cost per unit – creating a depth–temperature trade-off. Drilling is the largest cost component and rises non-linearly with depth, with per-well costs roughly doubling between 2 and 4 km and again between 4 and 6 km.⁴⁹ Usable output per well (typically 10–50 MW-th or ~3–10 MW-e in high-gradient fields) is determined by permeability and flow rates and the reinjection temperature differential. This sets the number of wells needed per kW, which translates directly into CAPEX per kW. The high share of upfront costs means levelised costs are highly sensitive to the WACC. Exploration risk keeps the initial WACC high, falling from ~16% at exploration to ~6% for mature operating assets as projects de-risk.⁵⁰ For direct-heat projects, distance to demand is an additional cost driver and projects are typically located near demand (e.g., under 10 km); extending a heat pipeline from 1 to 25 km could raise delivered LCOH by ~50%, driven mainly by pipe CAPEX and additional pumping.⁵¹ Combined heat and power can improve project economics by spreading CAPEX over more output (heat and electricity). Two emerging factors could improve the cost outlook and unlock new locations: AI-based exploration (e.g., Zanskar) is uncovering new conventional resources, potentially widening deployment;⁵² and co-production of minerals such as lithium or helium could add revenue in select basins.

⁴³ IEA (2024), *The Future of Geothermal Energy*.

⁴⁴ IEA (2024), *The Future of Geothermal Energy*.

⁴⁵ International Monetary Fund (2026), *Global Price of Natural Gas, EU [PNGASEUUSD]*. Available at: <<https://fred.stlouisfed.org/series/PNGASEUUSD>> [Accessed April 2026]

⁴⁶ International Monetary Fund (2026), *Global Price of Natural Gas, Natural Gas, US Henry Hub Gas [PNGASUSUSD]*. Available at: <<https://fred.stlouisfed.org/series/PNGASEUUSD>> [Accessed April 2026]

⁴⁷ LCOEs expressed in real 2025 \$/MWh-e. IRENA (2026), *Renewable Power Generation Costs in 2025*.

⁴⁸ IEA (2024), *The Future of Geothermal Energy*.

⁴⁹ NREL (2025), *Geothermal Drilling Cost Curves Update*; US DoE (2024), *Pathways to Commercial Liftoff: Next-Generation Geothermal Power*.

⁵⁰ 15–20% hurdle rates are typically required for conventional geothermal investment due to high project risk during early stages. This is higher than is typically achievable, meaning that more conventional projects have been cancelled than commissioned over the past decade. US DoE (2024), *Pathways to Commercial Liftoff: Next-Generation Geothermal Power*. True North Institute (2026), *Next-Generation Geothermal Energy*.

⁵¹ Pipeline temperature loss depends on pipe size, material, insulation class and condition, burial depth, fluid mass flow rate and velocity, and fluid temperature. LCOH calculations assume: a 90°C supply temperature and 50°C return temperature; 30 MW-th average delivered heat with 65% utilisation; 0.3 m diameter pipeline with \$1,500 per m CAPEX and 20 W per m heat loss, pumping requirements calculated using the Darcy–Weisbach pressure loss equation. Systemiq analysis for the ETC (2026); Aquatherm (2025), *Heat loss in district heating: causes, calculation & solutions*.

⁵² MIT Technology Review (2025), *How AI is uncovering hidden geothermal energy resources*.



Where resource quality is high, conventional hydrothermal is cost-competitive for firm power and can scale with policy support – particularly in Sub-Saharan Africa, Indonesia and Japan

EXHIBIT 5A **Global levelised cost of electricity (LCOE) ranges for key clean energy technologies in 2025** \$/MWh (real 2024)

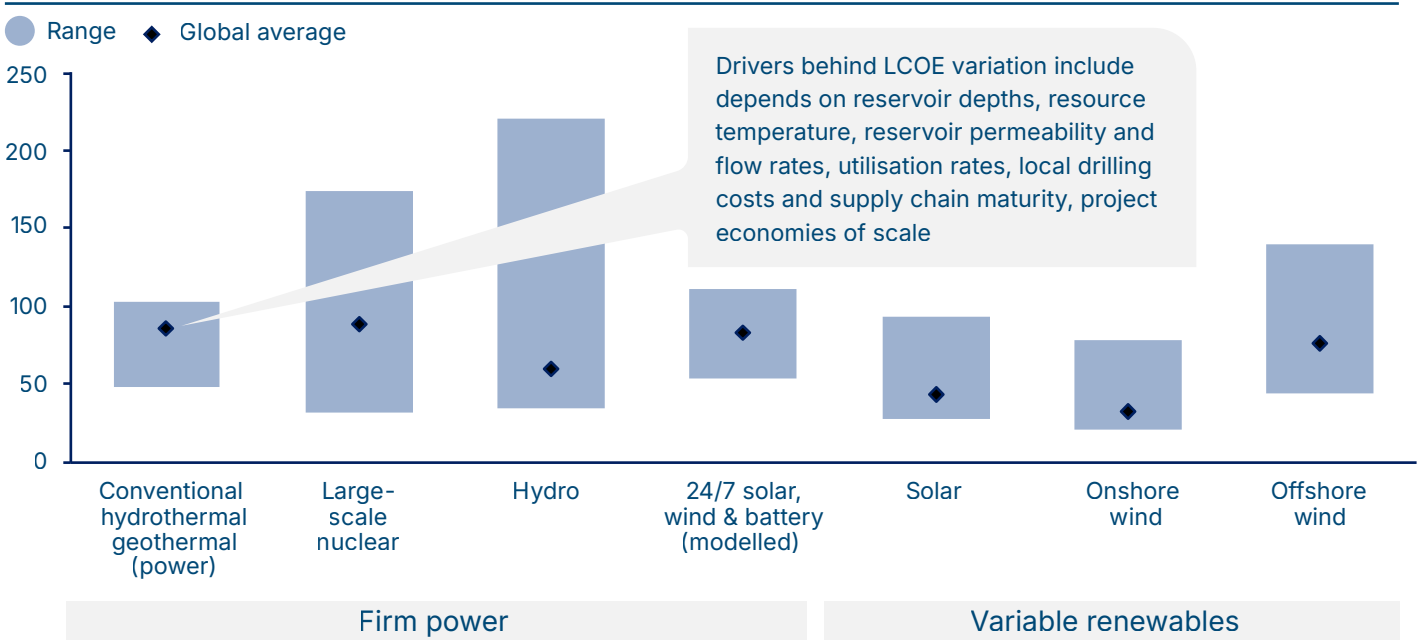
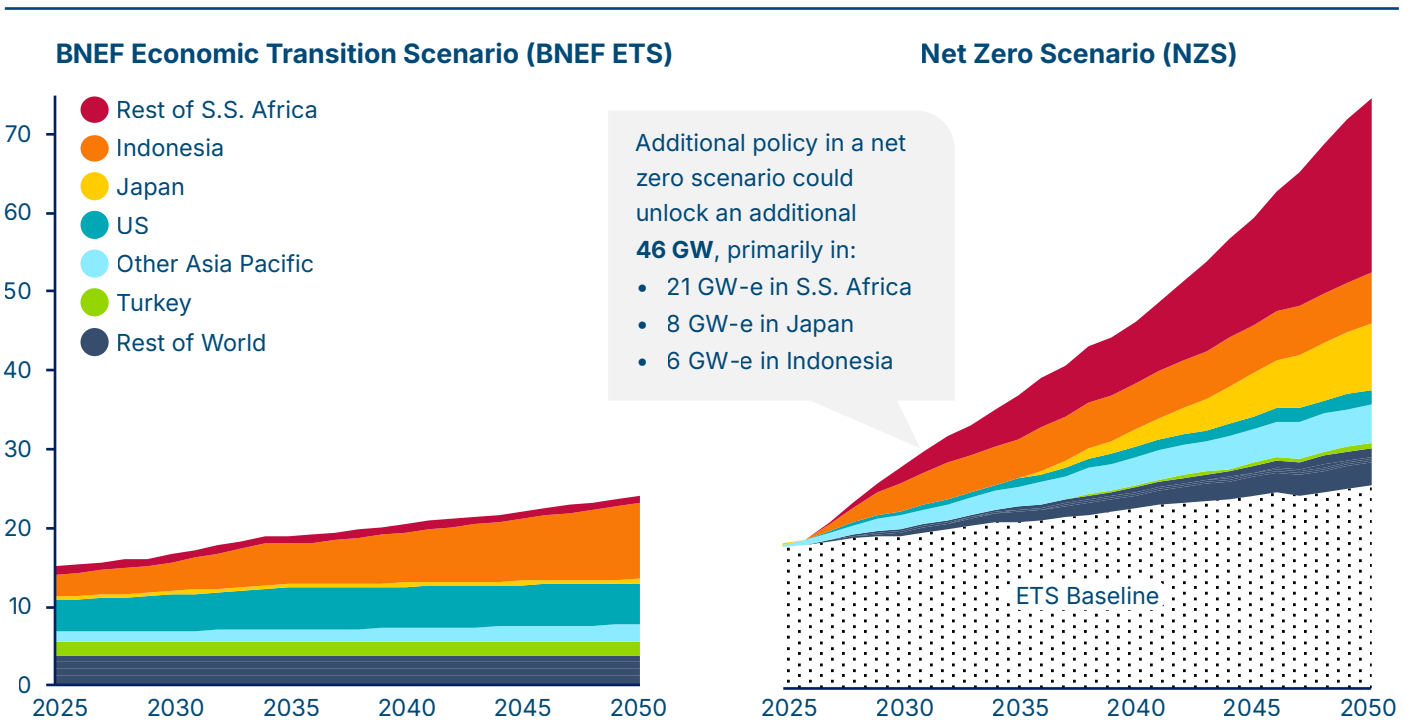


EXHIBIT 5B **Conventional hydrothermal power capacity by country/region (BNEF ETS vs NZS)**, GW-e



Notes: LCOE ranges are IRENA 5th to 95th percentiles and midpoints are IRENA's weighted averages, except for nuclear and 24/7 solar, wind & battery which are the range midpoints due to limited data availability. 24/7 solar, wind & battery LCOE represents IRENA modelling for solar and battery energy storage at 95% reliability. NZS = Net Zero Scenario; ETS = Economic Transition Scenario; "NZS 5" refers to the additional capacity in NZS, "ETS Baseline" refers to the overlapping demand in both. Rest of S.S. Africa = Rest of Sub-Saharan Africa (including all countries except South Africa); Rest of Latin America includes Argentina, Belize, Bolivia, Colombia, Costa Rica, Cuba, Ecuador, El Salvador, Guatemala, Haiti, Honduras, Jamaica, Nicaragua, Panama, Paraguay, Peru, Uruguay, Trinidad and Tobago, Venezuela; Rest of Europe includes Austria, Belgium, Bulgaria, Croatia, Cyprus, Czechia, Greece, Hungary, Ireland, Luxembourg, Malta, Netherlands, Romania, Slovakia, Slovenia, Switzerland.

Sources: KEARNEY Energy Transition Institute (2025), *Geothermal energy, turning up the heat*; IRENA (2026), *Renewable Power Generation Costs in 2025*; IRENA (2026), *24/7 Renewables: the economics of firm solar and wind*; IEA (2024), *The Future of Geothermal Energy*; BNEF (2026), *New Energy Outlook*

- **Cooling has significant untapped potential, particularly in developing economies:** Hot sedimentary aquifers can be used to provide cooling at district scale through absorption cooling. Where conventional air conditioning requires electricity to cool air, an absorption chiller requires hot water or steam, typically 80–100°C, to drive the refrigeration cycle. For countries facing acute cooling demand growth across the global “sunbelt”, absorption cooling is among the fastest and most capital-efficient geothermal applications, requiring neither the high-temperature resources needed for power generation nor the deep drilling that next-generation electricity projects demand. A key additional benefit is avoiding air-conditioning (AC) efficiency declines in densely populated areas, in which AC heat output, to produce cooling, increases ambient temperatures in the external environment. This, in turn, increases the electricity input needed to surrounding units to maintain desired temperatures. In the United Arab Emirates (UAE), a pilot plant in Masdar City already covers ~10% of the city’s cooling needs from ~90°C geothermal water.⁵³ High potential has been identified in large cities across the Philippines, Indonesia, Mexico, India and China.⁵⁴
- **Conventional hydrothermal power system value rests on the balancing and grid costs that other renewables would incur, as well as land constraints:** For power generation, conventional hydrothermal plants operate at capacity factors of 60–90% (maximised within thermal recharging constraints) – comparable to “baseload” fossil generation and materially higher than variable renewables on a firm-capacity basis. Firm low-carbon generation with higher capacity factors than variable renewables can decrease total system costs relative to 100% wind and solar systems by providing capacity when wind and solar output is low (reducing balancing and back-up costs) and enabling higher utilisation of grid assets. However, this benefit is limited by the fact wind and solar are steadily meeting increasing shares of demand in many systems,⁵⁵ a trend which is set to continue. Systems with high population density are likely to benefit the most from the lower land footprint.

Conventional hydrothermal can scale where geology, local off-take and appropriate financing coincide, but will be limited to low shares of global heat and power: Heat deployment can scale in regions with productive aquifers and available district-heating infrastructure or suitable industrial offtake, notably China, Germany, the Netherlands, France, Hungary, Türkiye, Iceland, Denmark and Italy.⁵⁶ The International Energy Agency (IEA) expects heat capacity could increase 3–5x to 400–700 TWh-th per year by 2050 but is likely to remain <1% of total heat demand in 2050.⁵⁷ BloombergNEF (BNEF) estimates that power deployment could increase by 1.5–4x to 25–80 GW-e by 2050 but will remain limited to <1% of global generation.⁵⁸ It will continue to be concentrated in tectonically active regions with high-grade resource and growing firm-power demand, including Kenya, Indonesia, Japan, the US, the Philippines, and Türkiye. [Exhibit 5]

⁵³ ADNOC (2023), *ADNOC and Tabreed Commence Operations at Region’s First Geothermal Cooling Plant in Masdar City*.

⁵⁴ IEA (2024), *The Future of Geothermal Energy*, using Project InnerSpace calculations for hot sedimentary aquifer systems based on GeoMap™ data with a cost threshold of \$40 per MWh; Project Innerspace (2026), *The Future of Geothermal in India. Powering economic growth and prosperity with abundant domestic energy*; Project Innerspace (2025), *The Future of Geothermal in Indonesia*.

⁵⁵ In the past five years, global annual generation from solar and wind has increased by 3,000 TWh per year, which is 8,600x the geothermal generation additions in the same period (~370 GWh per year). Analysis by ETC and others demonstrates how solar and wind can potentially reach over 60,000 TWh (75% of total) in a net-zero 2050 system, enabled by storage, flexibility and backup generation. Ember (2026), *Electricity Data Explorer*; ETC (2025), *Power Systems Transformation: Delivering Competitive, Resilient Electricity in High-Renewable Systems*; BNEF (2026), *New Energy Outlook*; IEA (2024), *Integrating Solar and Wind Global experience and emerging challenges*.

⁵⁶ IEA (2024), *The Future of Geothermal Energy*.

⁵⁷ IEA (2024), *The Future of Geothermal Energy*.

⁵⁸ BNEF (2026), *New Energy Outlook*; IEA (2024), *The Future of Geothermal Energy*.



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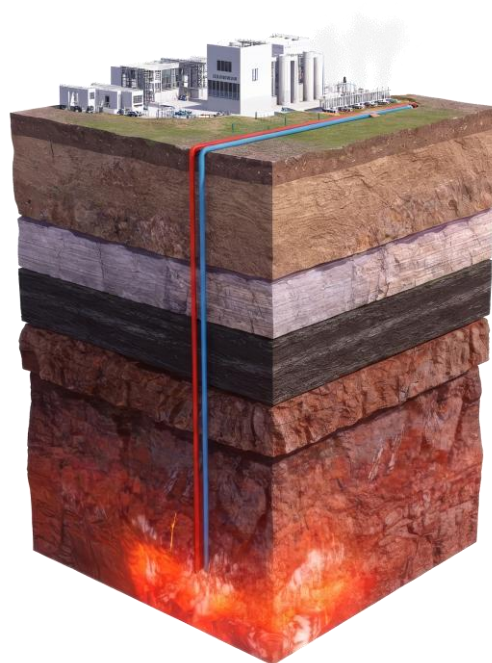
Next-generation geothermal can overcome geographic resource constraints, but current costs vary significantly depending on technology and location. These cost uncertainties will define the gap between optimism and reality.

Next-generation geothermal – enhanced geothermal systems (EGS), closed-loop geothermal systems (CLGS), and superhot rock (SHR) – use oil and gas (O&G) drilling techniques to access heat and power applications almost anywhere. This removes the geographical constraint that limits conventional geothermal to a narrow set of countries.

Next-generation geothermal technology has attracted substantial investment in the US, driven by its potential to supply round-the-clock clean power that data centre developers urgently seek. Initial results from Fervo Energy's Cape Station in Utah are technically promising, but remain to be proven at commercial scale. It could grow to meet ~0.2–5% of global final heat consumption and 0.4–8% of global electricity generation by 2050, from ~0% of both today, with the wide range reflecting high uncertainty around scalability.⁵⁹

The trade-off is maturity and cost: first-of-a-kind costs significantly across technologies and locations. Key uncertainties are whether the US cost declines (from \$15,000 per kW-e in 2023 to ~\$7,000 per kW-e today)⁶⁰ and reservoir performance now being demonstrated can transfer to other geologies.

For power, the global technical potential is large, but realistic 2050 deployment estimates range from 30 to 800 GW-e (generating ~200–6,000 TWh-e per year meeting ~0.4–8% of the IEA's estimated 60,000–70,000 TWh-e/year global electricity generation in 2050).⁶¹ This ~27-fold range reflects the same core uncertainties: the pace and extent of cost declines, whether successful reservoir performance is demonstrated, and how far US results transfer elsewhere.



⁵⁹ Systemiq back-calculations based on the IEA's Stated Policies and Announced Pledges scenarios. IEA (2024), *The Future of Geothermal Energy*.

⁶⁰ US DoE (2024), *Pathways to Commercial Liftoff: Next-Generation Geothermal Power – Updated*.

⁶¹ Estimated using a cap of 250°C. Higher temperature resources could expand this potential, particularly if SHR commercialises. IEA (2024), *The Future of Geothermal Energy*.



For heat, the potential is also substantial: ~0.2–5% of global final heat consumption through 150–4,200 TWh-th per year, meeting 4% of district heat (~1,400 TWh-th per year) and 9% of industrial heat (~2,800 TWh-th per year) by 2050.⁶²

Understanding the drivers of the cost range, and uncertainty around it, requires looking at how each technology works and how far each has travelled towards commercial maturity.

- **Next-generation technologies expand the accessible resource by engineering reservoirs (EGS, SHR) or constructing sealed wells (CLGS) but are still at low maturity:** Using O&G-derived horizontal drilling technologies, they can reach greater depths and higher temperatures at more locations. This reduces dependence on a naturally viable resource and reduces the exploration risk. This is because conventional hydrothermal requires all three conditions of high temperatures, natural permeability and water at drillable depth to be in place, which can only be confirmed during drilling. Next-generation technologies, by contrast, require only sufficient temperature, which is far more predictable from regional gradient data. Each technique is different, but each is at low maturity with EGS at TRL 7, CLGS at TRL 6 and SHR at TRL 3–5.⁶³
- **Next-generation geothermal can overcome geographic resource constraints, but costs vary widely by technology and location – closing that uncertainty will define the gap between optimism and reality.** As with conventional hydrothermal, next-generation projects are CAPEX-dominated, with upfront costs driven by drilling depth, resource temperature and achievable flow rates – and levelised costs highly sensitive to WACC. EGS drilling in hard rock has built on the optimisation of hundreds of thousands of unconventional oil and gas wells, and requires a skilled workforce with drilling expertise concentrated in the US.⁶⁴ In the near term, delivery risk is higher than for mature O&G drilling: with small well fleets, bespoke and site-specific wells offer less scope to average out underperformance, so a small number of poor wells can threaten overall project viability.⁶⁵ While project-level learning rates have been observed in demonstration projects (29% cost decline per doubling of wells drilled at Fervo's Cape Station), learning transferability to locations with different subsurface conditions is still unproven.⁶⁶ Mature heavy-infrastructure technologies (including conventional geothermal) typically show learning rates of ~5% per doubling of installed capacity; EGS is assumed to achieve a higher 5–10% rate, reflecting transfer from unconventional drilling



⁶² Systemiq back-calculations based on the IEA's Stated Policies and Announced Pledges scenarios. IEA (2024), *The Future of Geothermal Energy*.

⁶³ Additional innovations at low TRL today are the use of supercritical carbon dioxide as fluid instead of brine, laser-based drilling techniques for deeper wells (>5 km) and potential for combined carbon dioxide sequestration and geothermal heat extraction from saline aquifers.

⁶⁴ NREL (2025), *2025 Geothermal Drilling Cost Curves Update*; US DoE (2024), *Pathways to Commercial Liftoff: Next-Generation Geothermal Power – Updated*.

⁶⁵ M. Barnard (2025), *Beyond the Hype: Geothermal in Context Separating viable heat solutions from speculative drilling dreams*.

⁶⁶ True North Institute (2026), *Next-Generation Geothermal Energy*.



and early demonstrated gains.⁶⁷ With 7–10-year project cycles⁶⁸ and bespoke, site-specific designs, EGS could see ~4–5 capacity doublings by 2050, potentially yielding 20–40% CAPEX declines from early commercial deployment levels in the 2020s.⁶⁹ It is, therefore, uncertain whether cost declines will deliver next-generation power in low-temperature gradient locations, which could still cost over \$150 per MWh-e in 2035. [Exhibit 6] By contrast, more modular and standardised technologies like solar saw 11 doublings from 1975–2000 then another 11 doublings from 2000–2024 (decreasing module cost by 95% during each interval).⁷⁰

- Long-term reservoir performance is unproven – thermal drawdown and parasitic loads are uncertain but critical for commercial viability.** If reservoirs cool faster than expected (through thermal drawdown), LCOH or LCOE will increase regardless of drilling costs, as CAPEX is spread over lower output volumes. Pre-Fervo pilots (Hijori in Japan, Rosemanowes in the UK and Beowawe in the US) showed steep thermal drawdown within five to ten years of first production.⁷¹ In addition, parasitic loads – the energy required to pump cool water down thousands of metres into dense rock – can materially reduce net power output of EGS. This has made up ~30% of gross power production in early Fervo Cape Station data.⁷² The next 3–5 years of Cape Station operating data will be key evidence to resolve these operational uncertainties in a US high-temperature resource setting. However, a wider demonstration project evidence base across regions with other subsurface characteristics will be needed to inform broader scalability potential.
- In the near term, next-generation technologies are likely to scale in high-temperature gradient locations, where early deployment costs are tracking modelled declines.** Fervo Energy’s Cape Station EGS project (Utah, US) achieved ~\$7,000 per kW-e but is targeting \$3,000 per kW-e. This is materially lower than the costs of European first-of-a-kind (FOAK) projects that span \$26,000 per kW-e (United Downs, UK) to \$760,000 per kW-e (Eavor Geretsried). Eavor has already exhausted its \$380m CAPEX budget and delivered only 0.5 MW-e of a planned 8.2 MW-e (or 12 MW-th out of a planned 64 MW-th), equivalent to ~\$30,000 per kW-th.⁷³ While Cape Station built on Fervo’s previous EGS demonstration projects, this is a first demonstration of Eavor’s CLGS technology and costs closer to the Geretsried target, \$46,000 per kW-e or \$6,000 per kW-th, are likely to be achieved in future iterations. The IEA’s optimistic \$50 per MWh-e by 2035 trajectory likely reflects high-gradient conditions; low-gradient sites are not on track to reach it, largely because of the larger number of deeper wells needed, which drive up CAPEX [Exhibit 6].⁷⁴

⁶⁷ A. Malhotra (2020), *Accelerating Low-Carbon Innovation*.

⁶⁸ US DoE (2024), *Pathways to Commercial Liftoff: Next-Generation Geothermal Power – Updated*.

⁶⁹ Assuming 5–10% learning rate, and 4–5 doublings, from an initial “nth of a kind” capacity of 3.6 GW. US DoE (2024), *Pathways to Commercial Liftoff: Next-Generation Geothermal Power – Updated*.

⁷⁰ Our World in Data (2025), *Solar Photovoltaic Module Prices vs. Cumulative Capacity*.

⁷¹ Thunder Said Energy (2026), *Advanced Geothermal: Modelling the Reservoir?*; Thunder Said Energy (2026), *Modelling Geothermal: Energy Source or Magic Thermal Battery?*

⁷² GEO ExPro (2026), *World’s Largest Geothermal Reserves?* Available at: <https://geoexpro.com/worlds-largest-geothermal-reserves/> [Accessed June 2026]

⁷³ €350 million budget converted to \$380 million using 2024 average exchange rate: €1 = \$1.0822. Eavor (2026), *Technical Update from Geretsried: What We Built, What We Learned, and What Comes Next*; GEOExPro (2026), *Eavor Stepping Away from Operator Role in Geretsried*; Exchange Rates (n.d.), *Euro to US Dollar History: 2024*.

⁷⁴ Systemiq analysis for the ETC (2026); IEA (2024), *The Future of Geothermal Energy*.



Next-generation levelised cost of electricity (LCOE) will be highly dependent on temperature gradients

EXHIBIT 6A **Illustrative EGS cost variation by depth and temperature** 2035 cost estimates Heatmap LCOE – \$/MWh-e, real 2024

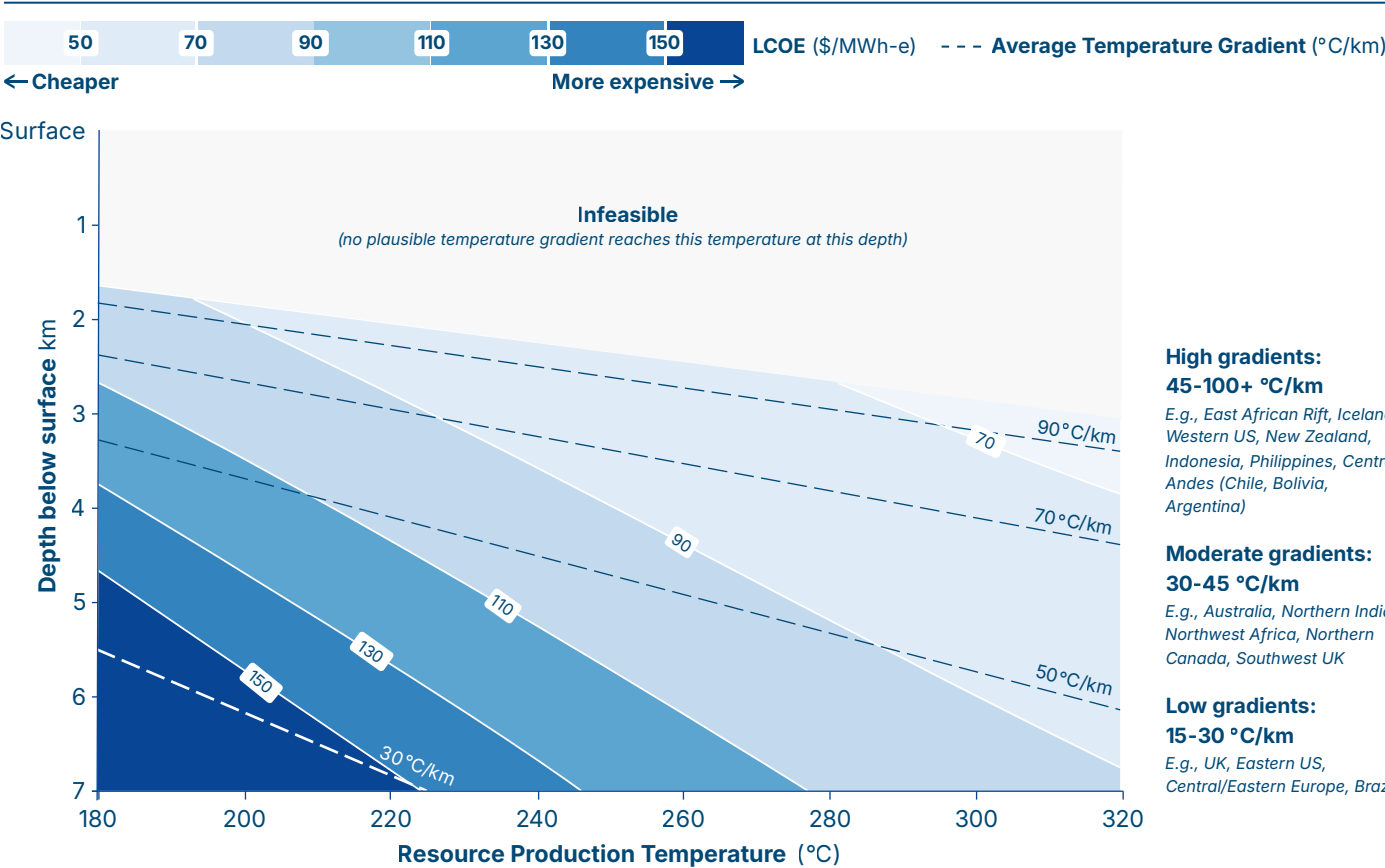
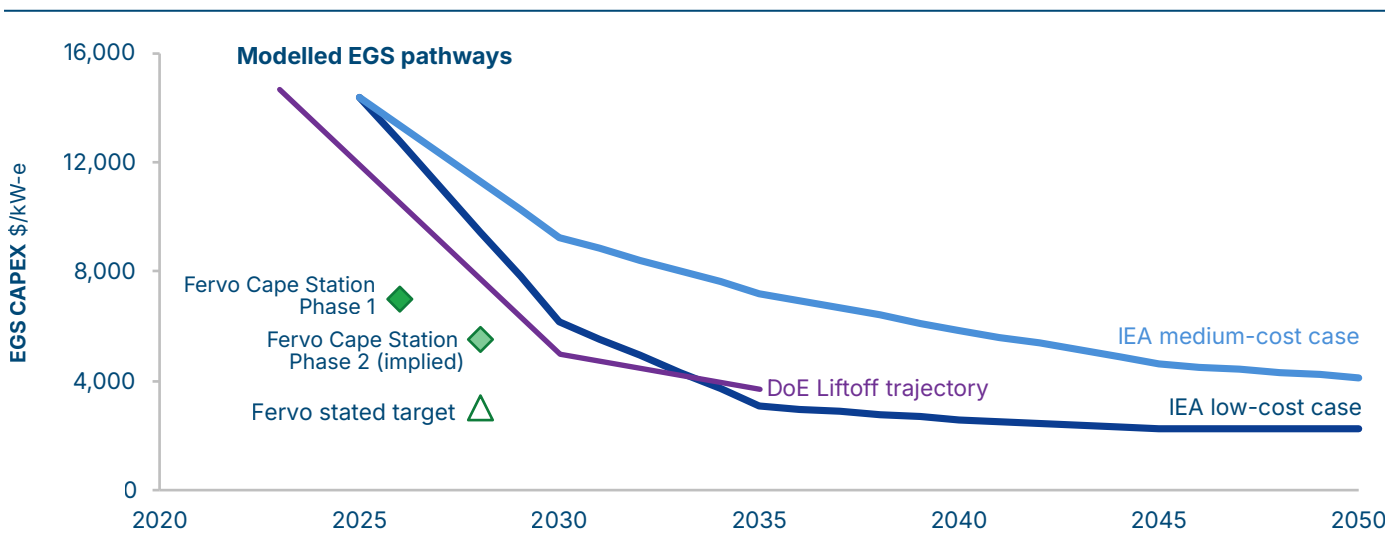


EXHIBIT 6B **Enhanced geothermal systems (EGS) disclosed vs. modelled EGS CAPEX data points, 2023 – 2050** \$/kW-e, real 2024



Notes: IEA modelled costs for 300 MW project, 3 km depth, 200°C in suitable conditions. DoE Liftoff anchored on 2023 FOAK (\$14,700 per kW-e) and 2035 Earthshot (\$3,700 per kW-e). Fervo Cape Station CAPEX range from April 2026 IPO filing; IEA series originally in 2023 MER USD; converted to real 2024 USD using ~2.5% deflator. EGS = Enhanced Geothermal Systems, WACC = Weighted Average Cost of Capital, LCOE = Levelised Cost Of Energy. Discounted-energy basis (7% real discount rate, 25-year life). RHS assumptions: 6 production + 2 reinjection wells; 80% capacity factor. CAPEX: temperature-dependent surface plant cost plus depth-dependent drilling cost (vertical large-diameter wells), DEVEX, other CAPEX, and OPEX in line with IEA and GEOPHIRES. Thermal drawdown of 1%/yr applied to production temperature (mature-technology end of the modelled 1–2%/yr EGS range; output assumed to track the design-temperature curve, an upper bound on late-life output, not yet demonstrated at commercial scale).

Sources: Systemiq analysis for the ETC (2026), drawing on IEA (2024), *The Future of Geothermal Energy*; US DoE (2024), *Pathways to Commercial Liftoff: Next-Generation Geothermal Power Updated*; Fervo Energy Inc. (2026), *Form S-1 Registration Statement*, filed with the US Securities and Exchange Commission. Available at <https://www.sec.gov/Archives/edgar/data/1853868/000162828026025821/fervoenergy-sx1.htm> [Accessed 05 2026]; NREL (2025), *2025 Geothermal Drilling Cost Curves Update*; Beckers (2019), *GEOPHIRES v2.0: updated geothermal techno-economic simulation tool*; US DoE (2024), *Pathways to Commercial Liftoff: Next-Generation Geothermal Power Updated*; Kolawole (2023), *Global distribution of geothermal gradients in sedimentary basins*; Limberger (2017), *Geothermal energy in deep aquifers: A global assessment of the resource base for direct heat utilization*.

- **Big tech is paying a premium for 24/7 carbon-free power co-located with data centres, and private capital is now validating next-generation bankability in the US.** Fervo and Google have signed a power purchase agreement (PPA) for the 3.5 MW Project Red and a clean transition tariff for the 115 MW Corsac demonstration projects, anchoring the EGS and data-centre product-market fit.⁷⁵ Fervo's 2026 initial public offering (IPO) raised ~\$2.2 billion at a ~\$10 billion open-day market capitalisation (the largest clean-energy listing on record), led by BofA Securities, Barclays, J.P. Morgan and RBC Capital Markets.⁷⁶ Fervo's March 2026 \$421m Cape Station financing facility, underwritten by Barclays, RBC, HSBC, and J.P. Morgan, was the first of its kind by not having DoE Loan Programs Office backing.⁷⁷
- **The power system-value case for EGS could be improved by flexible dispatch rather than "baseload" operation – if costs decline sufficiently:** Engineered EGS reservoirs can store pressurised geofluid and shift output across hours to seasons. This could allow the technology to serve the flexible-dispatch role created by solar- and wind-dominated systems. In-reservoir energy storage could enable multi-day load-following, providing maximum system benefits in solar-dominated systems with short-duration balancing needs. This can extend to cost-efficient seasonal storage, by oversizing the surface generation plant to capture peak power demand with relatively low additional capacity cost.⁷⁸ Modelled round-trip efficiencies of ~60–90% compare favourably to lithium-ion batteries at the high end and exceed most ultra long-duration storage alternatives (including metal-air and green hydrogen options).⁷⁹ The flexibility case still requires demonstration and will be conditional on continued cost declines to enable economic oversizing, which could limit impacts to the US in the medium-term.
- **If technical feasibility is proven in appropriate settings, next-generation heat applications could have strong potential where energy security needs push away from gas imports and high power prices and grid constraints limit cost-competitiveness and scalability of alternatives:** EGS and CLGS can deliver heat at up to 300°C and can, therefore, provide low- to medium-temperature heat to the food, beverage, paper and pulp and select chemical industries. They face competition from high-temperature heat pumps and e-boilers in most contexts, but a near-term market exists in regions with high power prices, constrained electricity supply or grid capacity, or gas-import dependent regions (e.g., Europe, Japan and South Korea). Their LCOH could decline from \$80–150 per MWh-th at first-of-a-kind to \$20–80 per MWh-th by 2035.^{80,81} This future cost range overlaps with that of industrial heat pumps (\$30–100 per MWh-th), electric boilers (\$50–150 per MWh-th) and natural gas boilers (\$10–100 per MWh-th) [Exhibit 7]. Competitiveness depends on where projects land within these ranges, which reflects local geology (and technical/economic derisking), gas and power prices and the availability of sufficient co-located heat demand (due to high cost of heat transport, driven by pipeline costs). Where electricity is cheap and process temperatures are below ~150°C, electrified alternatives will generally be cheaper than geothermal; where power is expensive or constrained and temperatures exceed heat pump limits, next-generation geothermal could become a more competitive option. Energy security could be a key driver for adoption: next-generation geothermal heat would be a fully sovereign industrial input, with no ongoing fuel or electricity input.

⁷⁵ Clean Technica (2024), *Google Agrees to Buy 115 MW of Geothermal Power from Fervo & NV Energy*.

⁷⁶ The IPO raised 1.9bn as the base offering; total proceeds were ~\$2.2bn with the over-allotment. Fervo (2026), *Fervo Energy Announces Upsized Proposed Initial Public Offering*.

⁷⁷ Cleantech Group (2026), *Fervo's IPO Establishes Enhanced Geothermal Baselines, Presents New Competition to Fission, and Adds a New LDES Class*.

⁷⁸ Ricks et al. (2024), *The Role of Flexible Geothermal Power in Decarbonized Electricity Systems*, Nature Energy.

⁷⁹ Ricks et al. (2024), *The Role of Flexible Geothermal Power in Decarbonized Electricity Systems*, Nature Energy.

⁸⁰ Systemiq (2024), *Global opportunities for Electrothermal Energy Storage*.

⁸¹ In the IEA's Announced Pledges Scenario, on modelled assumptions of subsurface costs \$1,000–3,000 per kW-th, plant costs \$150 per kW-th. IEA (2024), *The Future of Geothermal Energy*.



Next-generation geothermal could become competitive for low-temperature industrial heat in regions with high gas prices in the 2030s

EXHIBIT 7A **LCOH for direct heat use in low-temperature industrial heat (<200°C) in the IEA's Announced Pledges Scenario (APS), 2035**
\$/MWh-th (real 2024)

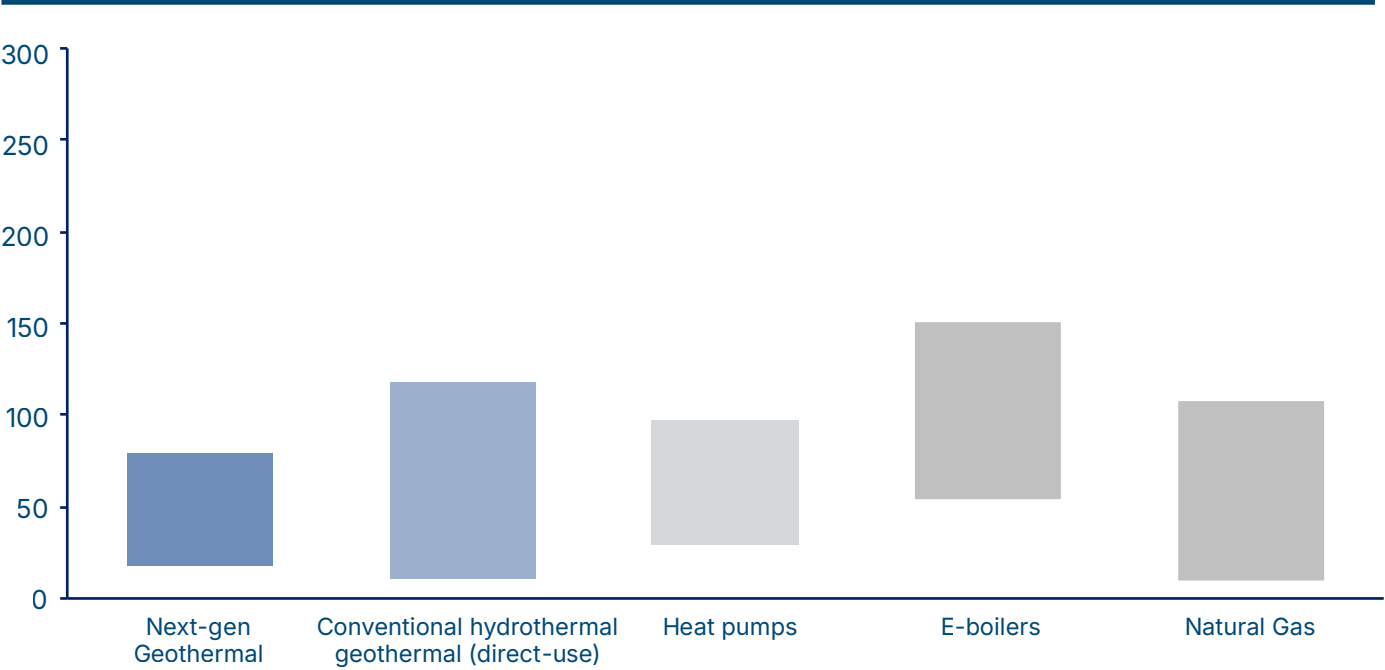
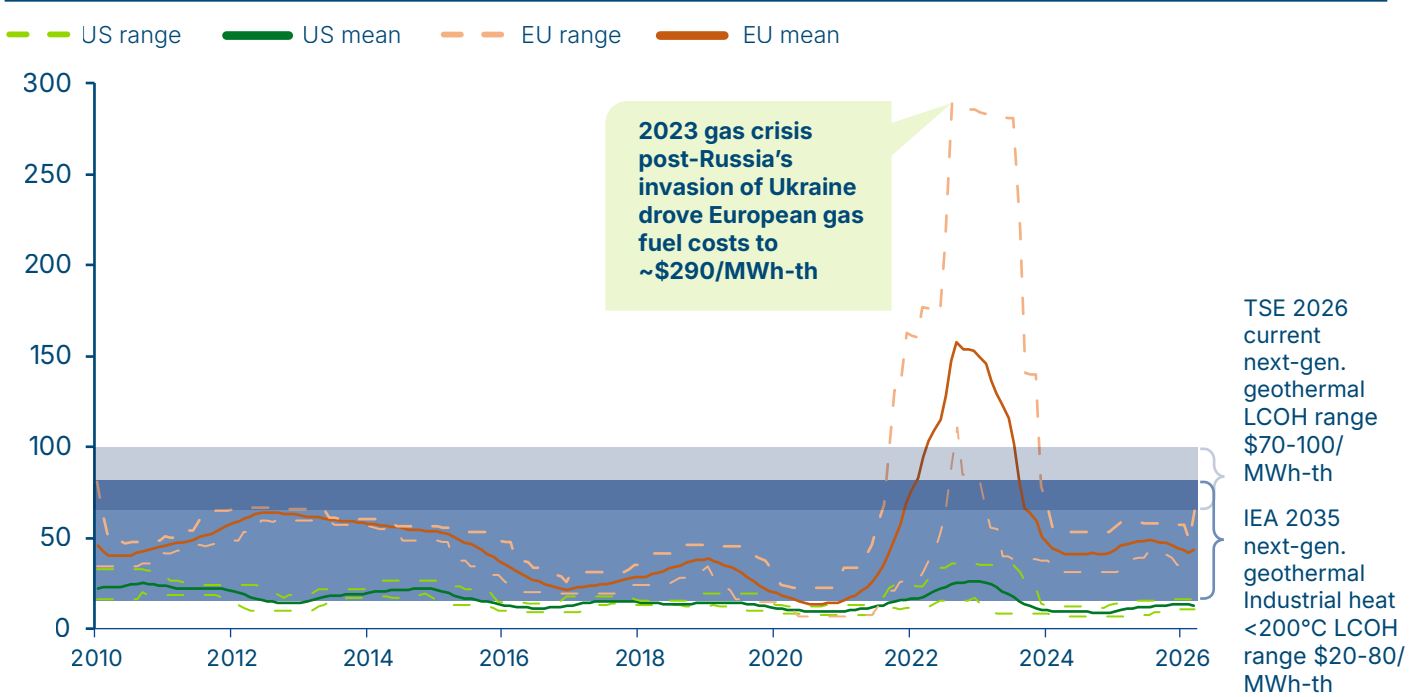


EXHIBIT 7B **Gas fuel cost per MWh-th delivered in US vs EU (rolling 12-month mean and ranges) and next-generation geothermal ranges**
\$/MWh-th (real 2024)



Notes: Natural gas prices converted from \$ per MMBtu to \$ per MWh-th using 1 MWh-th = 3.412 MMBtu, then converted to delivered cost of heat using an assumed modern industrial gas boiler efficiency of 90% and deflated to Real 2024 USD using US CPI. Range reflects the monthly high-low within the rolling 12-month window. Series tracks the IMF's European natural gas benchmark, historically anchored on Russian-German border pipeline prices and tracking closer to TTF spot prices from 2022 onwards. US series: Henry Hub.

Source: IEA (2024), *The Future of Geothermal Energy*; International Monetary Fund (2026), Global price of Natural gas, EU [PNGASEUUSD], Available at: <https://fred.stlouisfed.org/series/PNGASEUUSD> [Accessed 04 2026]; International Monetary Fund (2026), Global price of Natural gas, Natural Gas, US Henry Hub Gas [PNGASUSUSD], Available at: <https://fred.stlouisfed.org/series/PNGASEUUSD> [Accessed 04 2026]; IEA (2024), *The Future of Geothermal Energy*; Thunder Said Energy (2026), *Next-gen geothermal: progress update*.



Geothermal has lower environmental impacts than fossil alternatives, but environmental and social risks have halted a small minority of projects in various countries. Community consent and the avoidance of sensitive sites can determine both how and whether a project proceeds.

Like all infrastructure projects, geothermal projects must be appropriately sited to minimise surface and subsurface environmental damage and go through appropriate community engagement. Geothermal projects typically do not cause higher levels of surface-level damage than other energy projects and its high energy density means it typically requires a small land footprint relative to the power or heat delivered.

The environmental risk profile varies significantly by technology. Shallow systems carry limited risk: low drilling depths and operating pressures mean no geofluid emissions and no induced seismicity risk (i.e. earthquakes and tremors directly caused by human activities). Deep geothermal (conventional hydrothermal and next-generation systems) carries more fundamental risks if not properly designed or operated, spanning man-made earthquakes, groundwater contamination and emissions of hydrogen sulphide (H₂S) and carbon dioxide (CO₂). However, boreholes can be designed and constructed to mitigate for this, and across most risk categories, geothermal technologies are lower risk than O&G hydraulic fracturing [Exhibit 8].

- **Shallow geothermal carries substantially lower environmental risk than deep geothermal:** Low drilling depths, low operating pressures and no hydraulic stimulation mean no induced-seismicity (man-made earthquake) exposure and no geofluid emissions risk. The most material residual concern is aquifer thermal disturbance in ATEs projects, where seasonal heat injection and extraction can alter local groundwater temperatures and microbiology – managed through standard permitting and operating practice.
- **Conventional hydrothermal and EGS face the highest risks, but each is technology-specific:**
 - The key trigger mechanisms for seismicity are the high pressure associated with hydraulic fracturing (for EGS) or large fluid flow through geothermal production in naturally stressed reservoirs (for conventional hydrothermal).
 - Groundwater contamination applies to both, driven by well-integrity and fracture-propagation concerns; addressed through sealed casing and cementing standards.
 - Small-scale emissions of H₂S and CO₂ occur when native reservoir fluids are vented. Emissions are low where abatement and monitoring are enforced, but poorly managed



venting has caused fatalities – as at Sorik Marapi, Indonesia.⁸² Closed-loop systems eliminate this risk.

- **CLGS avoids both seismicity and emissions risks by design:** The working fluid circulates through a sealed wellbore without contacting the host rock, avoiding hydraulic stimulation and venting of native geofluids. Groundwater protection is still required – comparable to deep O&G drilling – and is addressed through standard casing practice.
- **Deep geothermal environmental risks have halted past projects, though these make up a small share of the ~200 conventional hydrothermal fields in operation across more than 30 countries:**⁸³ Projects were cancelled or suspended in Basel in 2009 after hydraulic stimulation triggered a 3.4 magnitude earthquake in 2006, and Pohang in 2017 following a 5.4 magnitude event linked to EGS activity.⁸⁴ These risks are managed through established protocols – seismic monitoring, staged stimulation and well-integrity standards – that allow operators to detect and respond to signs of geological stress before they escalate.
- **Community consent is an important consideration for all large-scale geothermal developments.** In Indonesia, attempted development on Flores had inadequate community engagement and the World Bank withdrew from the development in December 2023.⁸⁵ Development had been stalled by significant local opposition driven by environmental degradation, displacement from ancestral lands and loss of livelihoods. Disruption to local communities and ecosystems should be avoided through early, transparent community engagement, including Free, Prior and Informed Consent (FPIC) guidelines where projects affect indigenous or customary land or rights. Responsible operators should also screen out environmentally and culturally sensitive sites at the siting stage, and apply environmental safeguards and benefit-sharing mechanisms throughout the project.
- **Community acceptance, appropriate site selection, and avoidance of environmentally and culturally sensitive areas** are, therefore, critical determinants of project viability. Alongside these, key technical mitigations for deep geothermal include: traffic-light protocols to monitor induced seismicity and pause operations if a threshold event is observed (e.g., the US DoE's Protocol for Addressing Induced Seismicity Associated with Enhanced Geothermal Systems, operational at Cape Station); reporting of water use; ensuring wellbore integrity including sealed casing standards to prevent contamination of shallow aquifers drilled through to reach deeper hot zones; voluntary reporting of drilling-related chemicals; and closed-loop fluid management to eliminate emissions of H₂S and CO₂ from native geofluids.⁸⁶



⁸² Human Rights Monitor (2022), *Dozens poisoned with hydrogen sulfide gas due to PT SMGP's operations in North Sumatra*. Available at: <<https://humanrightsmonitor.org/case/dozens-poisoned-with-hydrogen-sulfide-gas-due-to-pt-smgps-operations-in-north-sumatra/>> [Accessed June 2026]

⁸³ Over 30 countries currently have geothermal power capacity installed. Conventional Geothermal Energy Gutiérrez-Negrín, L. A. (2024), *Evolution of worldwide geothermal power 2020–2023*.

⁸⁴ AnotherDay (2023), *The Pohang Earthquake and the Implications for Geothermal Energy*. The Guardian (2009), *Swiss Geothermal Power Plan Abandoned After Quakes Hit Basel*.

⁸⁵ Carnegie (2025), *The Paradox in Southeast Asia's Decarbonization Agenda*. Available at: <<https://carnegieendowment.org/research/2025/09/southeast-asia-decarbonization-geothermal-backlash-protest>> [Accessed June 2026]

⁸⁶ US DoE (2012), *Protocol for Addressing Induced Seismicity Associated with Enhanced Geothermal Systems*; US DoE (2024), *Pathways to Commercial Liftoff: Next-Generation Geothermal Power*; Fervo (2024), *Fervo's Approach to Induced Seismicity Management*.



Geothermal environmental risks are technology- and site-specific, manageable with modern practices and lower risk than oil and gas

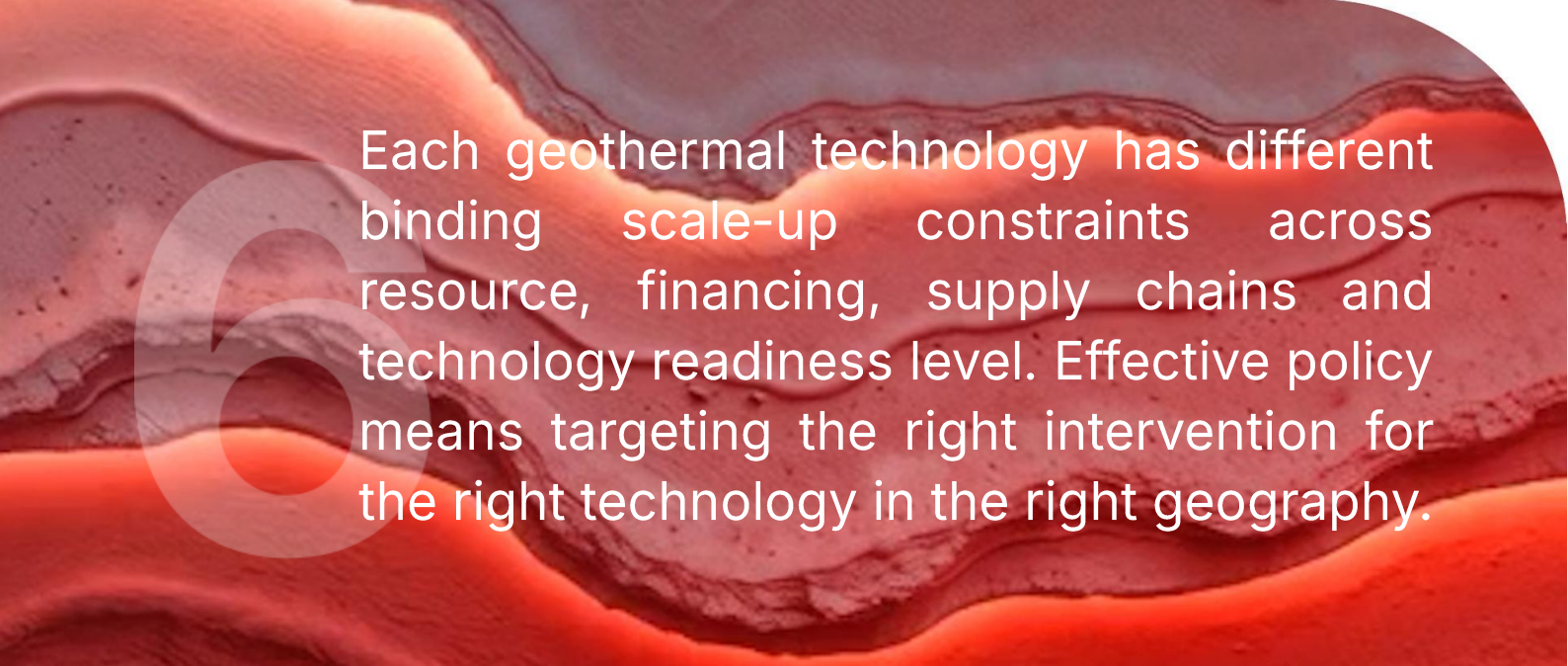
EXHIBIT 8 **Comparison of environmental risks across geothermal technologies and oil and gas**

		Risk level				
Risk	Description	Shallow (GSHP and UTES)	Convent- ional hydro- thermal	Next-generation		Oil and gas hydraulic fracturing
				CLGS	EGS and SHR	
Induced seismicity	Earthquakes from injection/ extraction: small tremors triggered by fluid movement.	None	Medium	Low	Medium	Low
Groundwater contamination	Water quality impacts from substances entering supply: leakage of drilling fluids, chemicals, arsenic, boron or hydrogen sulfide.	Low	Low-Medium	Low	Low-Medium	Medium
Disruption of local water supply	Water quantity impacts from extraction: alteration or depletion of aquifers.	Low (none for closed-loop systems)	Low-Medium	None	Low-Medium	High
Relative emission of gases	Gases into atmosphere: emission of CO ₂ , methane, hydrogen sulfide and other trace gases during development or operation.	None	Medium	None	Low	High
Land subsidence	Surface compaction from pressure changes: ground deformation from fluid withdrawal.	None	Low-Medium	Low	Low	Low-Medium
Other local impacts	Noise, visual impact or surface disturbance.	Low	Low-medium	Low	Low	High

Notes: Ground-source heat pumps (GSHP), underground thermal energy storage (UTES), conventional hydrothermal, closed-loop geothermal systems (CLGS), enhanced geothermal systems (EGS), superhot rock (SHR). Risk levels reflect published reviews and regulatory assessments. Actual impacts depend on geology, design, regulation and operator practice.

Sources: U.S. Department of Energy (n.d.), *Geothermal – Environmental Analysis*; Clean Air Task Force (2025), *Introduction to the Next Clean Energy Frontier: Superhot Rock Opportunities and Responsible Development*; Union of Concerned Scientists (2024), *Environmental Impacts of Geothermal Energy*; BKV Energy (2024), *Environmental Impact of Geothermal Energy*; Fiveable (2024) *Environmental Impacts of Geothermal Energy*; International Energy Agency (2013), *Golden Rules for a Golden Age of Gas*.





Each geothermal technology has different binding scale-up constraints across resource, financing, supply chains and technology readiness level. Effective policy means targeting the right intervention for the right technology in the right geography.

Heat and electricity supplied by geothermal technologies could increase by 4–20x and 6–65x respectively based on current estimates, raising geothermal's share of final heat consumption to 1–8% and of electricity generation to 1–9%. The potential for scale of each geothermal technology group varies per region: [Exhibit 9]

- **Shallow geothermal** can scale in all countries with seasonally varying heating- and/or cooling-demand.
- **Conventional hydrothermal** will grow in a subsection of countries but remain limited globally.
- **Next-generation geothermal** is likely to commercialise in the US but expansion beyond remains uncertain.

The extent to which the potential can materialise globally will depend on whether supportive policy is adopted to unlock investment and, above all, on whether next-generation technology costs fall significantly. The growth of conventional hydrothermal and next-generation technologies could be concentrated in locations with high temperature gradients (including the East African Great Rift Valley and Pacific Ring of Fire), making the lower end of the overall growth potential most likely. This development needs to be carefully managed, integrating social justice and land use concerns.



Geothermal meets under 1% of heat and power today, but could rise to between 1–9% by 2050 for each, depending on whether next-gen. scales

EXHIBIT 9A **Heat – Estimated 2024 and 2050 geothermal global heat supply by technology type and total share of final heat consumption**

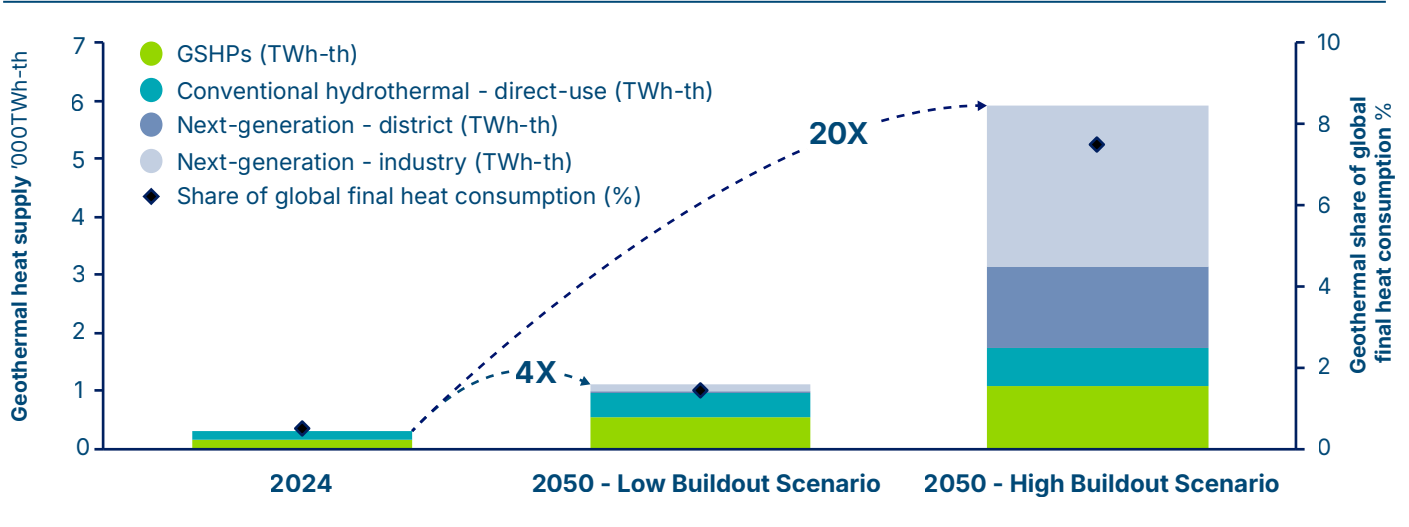
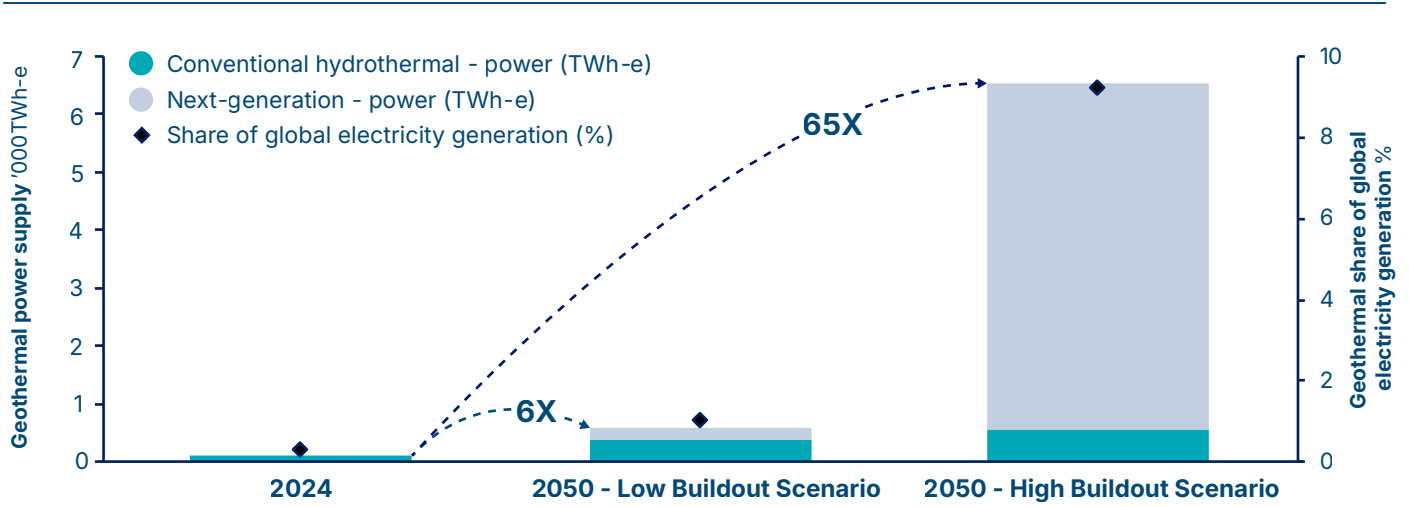


EXHIBIT 9B **Power – Estimated 2024 and 2050 geothermal global electricity supply by technology type and total share of electricity generation**



Notes: GSHP = ground-source heat pump. Today represents the most recent capacity/generation estimates available (2024). 2050 low and high estimates reflect IEA Stated Policies Scenario and Announced Pledges Scenario estimates, respectively, apart from: the low cases for next-generation - district & industry, which reflect Systemiq estimates assuming the same low to high ratio as IEA's next-generation power estimates, and GSHPs, which uses IEA's SP as the low case and ETC assumptions based on GSHPs meeting 5% of heat pump growth in BNEF's Net Zero scenario as the high case. Share of global final heat consumption in 2024 estimated using IEA Renewables 2025 global heat consumption data. Next-generation - district refers to next-gen co-generation. Power estimates for 2050 are based on IEA's low to high range of 30 – 800 GW and an assumed capacity factor of 85%. UTES time-shifts heat sourced elsewhere rather than representing an independent delivered-heat resource.

Sources: Systemiq analysis for the ETC (2026); IEA (2024), *The Future of Geothermal Energy*; IEA (2024) *Renewables 2025*; BNEF (2026), *New Energy Outlook*



Policy priorities to unlock scale follow from that split: each technology has a different binding constraint, and progress in the coming decades depends on key policy support:

- **For shallow geothermal**, the long-term economics already work – the binding constraints are financial and institutional. Policy focus should be on addressing the upfront ~\$20k cost barrier for households through targeted capital subsidies, stamp-duty differentials, building-code mandates for new-builds, asset-linked concessional loans, and creating the regulatory framework to incentivise (private sector) mortgage integration and on-bill repayment systems. GSHPs make up ~10% of heat pump capacity today, and a focused effort to scale them in appropriate cold-climate locations (likely concentrated in China, the US and Northern/Eastern Europe). Current trends suggest a ~1% share of global heat demand share as heating systems continue to electrify around the world, increasing deployment by 4–6x to 20–40 million units by 2050 based on current trends. Similarly, a reasonable threshold for UTES in systems with seasonal supply and demand swings could be ~10% of heating demand.
- **For conventional hydrothermal**, the binding constraint is resource and drilling risk, and the policy template is well established. Policymakers should focus on public de-risking of exploration and drilling through state-backed exploration vehicles and drilling-risk insurance schemes and better regulatory and permitting predictability. District-scale cooling should be a key emerging focus in many “sunbelt” countries around the world. Targeted support could increase direct-heat use by 3–5x to 400–700 TWh-th per year by 2050 and unlock 80 GW-e of new power capacity (from 17 GW-e today) in resource-rich locations (notably Indonesia and Kenya). However, conventional hydrothermal is unlikely to exceed 1% of global final heat consumption and power supply.
- **For next-generation geothermal**, the key question is whether the cost declines and operating performance now being demonstrated in the US prove transferable, and policy can shape that answer in two ways. The first lever is through supporting test centres in different settings to demonstrate next-generation systems across geologies, FOAK risk-sharing with exploration grants, drilling-risk insurance, contracts-for-difference and public co-investment. The second is purpose-built regulatory frameworks for novel subsurface activity: induced-seismicity management for EGS and clear permitting categories for EGS and CLGS, neither of which fit existing geothermal codes. Next-generation heat could reach 4,000 TWh-th per year by 2050, providing up to 5% of global final heat consumption (though district industrial heat). Realistic next-generation power capacity by 2050 is still highly uncertain and could range from 30–800 GW-e, providing 0.4–9% of an expanded, highly electrified global power system.

Across the three technology families, the pattern is consistent: geothermal has a growing role in heating, cooling and power. For all three, the upper bound is significant but highly uncertain given required cost reductions in next-generation technologies and successful policy implementation. Shallow systems can decarbonise building heating and cooling almost anywhere, and conventional hydrothermal and next-generation can supply industrial process heat where the resource or the economics allow. Power applications will stay confined to hot hydrothermal reservoirs and, potentially, next-generation if US cost declines prove transferable. Geothermal will not be a universally applicable technology, but where geology, demand and supportive policy align, geothermal offers something few clean energy technologies can match: clean heating and cooling, firm power and seasonal storage, from a secure domestic resource.



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The team that developed this briefing comprised:

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