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Hot Dry Rock Geothermal Power Generation Estimates for the USA (L48) Using Reduced Order Physical Models

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ABSTRACT

Emerging Hot Dry Rock (HDR) technologies such as Geopressured Geothermal Systems (GGS), Enhanced Geothermal Systems (EGS), and Advanced (closed-loop) Geothermal systems (AGS) offer promising pathways for electricity production, particularly in areas without significant subsurface aquifers. GGS is a variant of HDR geothermal systems, which involves injecting water into a well, creating a fracture system and operating wells in a "huff-and-puff" manner in low-permeability, low-porosity rock. For HDR power generation, two key requirements are: (1) access to rock formations exceeding 150°C and (2) engineering fracture systems that can work as downhole heat exchangers.

This study presents updated resource estimates for HDR power generation potential in the contiguous United States, focusing on depths of 3, 4, 5, and 6 km. The estimates are based on recent data for subsurface temperatures up to 180°C and consider heat conduction, convection, and depletion physical models to assess the energy extractable over a 30-year plant lifespan. The analysis excludes areas unavailable for industrial development (e.g., national and state parks, conservation zones, and mountainous regions). Our findings indicate a geothermal generation potential of over 5 TW for resources shallower than 5 km and 13 TW for resources less than 6 km.

We also provide Levelized Cost of Electricity (LCOE) estimates at each depth in the explored interval. Our analysis shows that LCOE increases with depth, with surface equipment costs becoming the dominant driving force of capital expenditures (CAPEX) over drilling costs. Beyond 6 km, HDR projects encounter challenges with current technologies, highlighting a need for innovation in drilling, completion, and surface technology to unlock the potential of deeper HDR geothermal resources.

1. INTRODUCTION

Recent advances in oil and gas technology have lowered previous estimates for capital costs and considerably improved the returns on investment of subsurface drilling and completion-related projects in the United States (Nadimi et al., (2020); Beard & Jones (2023). At the same time, novel techniques for subsurface development in existing geothermal fields using pressure-propped fractures (Simpkins et al., 2023; Rivas et al., 2024) as well as proppant-propped fracture systems (Nadimi et al, 2020) have led to commercial-scale field demonstrations of man-made subsurface connectivity in "hot dry rock" (HDR) environments.

Traditional hydrothermal-geothermal energy is already a mature renewable resource in terms in the United States, where 17 billion kWh are produced each year (IEA 2023). The United States has the most installed geothermal capacity in the world, at approximately ~4 GW. (NREL, 2021). At the same time, geothermal power production remains less than 1% of the US power supply (IEA 2023). Emerging hot dry rock or aquifer-independent geothermal systems offer a pathway to develop geothermal potential in broader geographies and closer to population centers, in addition to a relatively small surface footprint (Beard & Jones, 2023).

Previous studies of the resource base for 'next generation geothermal' development in the United States have varied considerably, incorporating different approaches to estimating depth to subsurface heat, as well as different approaches to estimating surface power generation and capital expenses. Estimates have varied as widely as 150 TW of economical, recoverable geothermal power potential (USGS, 2008; Augustine et al., 2023; Blankship et al., 2024). More recently, supply chain constraints have developed in the aftermath of post-COVID19 pandemic global economic conditions. In this context, we provide here an updated perspective on the techno-economics of 'next generation' geothermal systems, with specific approaches in terms of subsurface resource estimates, surface project development costs, and overall expected levelized cost of electricity (LCOE).

Subsurface characterization for enhanced or man-made subsurface heat exchange engineered geothermal resources builds on decades of research, especially work at Fenton Hill (U.S. Department of Energy (DOE, as summarized in Brown (2009)), Pleasant Bayou (Gulf Coast Geopressured-Geothermal Program, DOE; as summarized in John (1998) and (Riney (1991)), Utah FORGE (FORGE, 2020) and the GeneSys Project of Hannover Germany (Jung et al. (2005; Tischner, 2010). Research from Southern Methodist University (SMU) labs and the Bureau of Economic Geology of The University of Texas have also provided detailed studies of the resource base (Blackwell et al., 2011; Batir & Richards, 2021). More recently, Stanford University researchers have updated resource estimates using more advanced techniques for the Lower 48 states (Aljubran & Horne, 2024a,b,c). At the same time, advanced surface power plant designs (Bronicki et al., 2007) provide critical surface kit for efficient and increasingly economic heat transfer and power production. This study integrates updated analyses of all of these factors.

2. DATA & METHODS

This interpretation builds on Aljubran and Horne's Subsurface Thermal Model (STM) (2024b), a tool for predicting temperature-at-depth, surface heat flow, and rock thermal conductivity across the contiguous United States (L48). The STM incorporates over 400,000 bottomhole temperature (BHT) measurements, sediment thickness, magnetic and gravity anomalies, gamma-ray flux of radioactive elements, seismicity, elevation, and electrical conductivity into a high-resolution 3D model with national scale. One of the STM's key advantages over previous models is its fine spatial grid. Each grid cell represents an area of 18 km^2 in the STM while the SMU model (Blackwell et al., 2011) was gridded in roughly 64 km^2 cells. The SMU model relies on BHT measurements, depth, surface coordinates, rock thermal conductivity, sediment and basement heat flow, and radioactive heat generation for temperature-at-depth predictions. The STM benefits from broad inclusion of geophysical and geochemical variables, enabling it to deliver more comprehensive predictions than previous models. Pending additional revisions to other holistic physics-based resource models, we selected the STM and methods it incorporates.

For this paper, the 180°C isotherm is assumed to be the target of HDR development as a reference for temperatures likely to exceed 150°C at surface and provide some degree of economic return on investment using current mid-enthalpy geothermal heat conversion technologies. In each 18km^2 grid cell, the depth to 180°C is estimated and binned by kilometer according to its depth to 180°C (1-2 km, 2-3 km, etc.). The outputs of the STM are the foundation for our estimates of geothermal generation capacity potential across the continuous United States. Cells where the depth to 180°C is greater than 6 km are excluded due to technical constraints that will be covered in the discussion section of this paper. Similar to previous studies, we remove areas where environmental, social and/or governmental factors would prevent HDR geothermal development, including national and state parks, wilderness and tribal lands. Mountainous terrain, defined as having a slope greater than 15 degrees, was also removed from the binned areas.

To estimate the HDR power generation potential in the contiguous United States, we adopted a techno-economic modeling approach informed by recent studies, resource maps, and engineering assumptions. HDR projects where the desired heat resource is deep will require significantly greater capital to execute higher pressure requirements for the surface equipment. Past methodologies have argued that higher efficiency of heat to electricity conversion found in hotter reservoirs offset the CAPEX requirement to drill deeper. This concept is revaluated in our study.

We refined these previous methodologies to estimate practical HDR power generation potential. Our analysis targeted depths of 3, 4, 5, and 6 km and focused on achieving subsurface temperatures of 180°C and binary power plants with heat exchanger inlet temperatures at 150-160°C. This thermal loss aligns with observations from past HDR projects (Tischner et. al, 2010) (Hogarth, 2013). Our techno-economic model assumes a horizontal well design inspired by the geothermal industry's advancements (Norbeck & Latimer, 2023). Specifically, we considered a 2,000 meter horizontal well length with 120 meter lateral spacing to avoid thermal interference between fractures.

In the past, a few publications estimated geothermal resources for HDR based on calculating heat in place and multiplying by recovery factor and power plant efficiency term (Tester, 2006).

$$P = \boldsymbol{\eta_{th}} \mathrm{Q_{rec}} \tag{1}$$

Where P is electric-generating capacity, $\boldsymbol{\eta_{th}}$ is cycle thermal efficiency, and $\mathrm{Q_{rec}}$ is recoverable heat,

$$\mathrm{Q_{rec}} = \mathrm{F_r} \rho \mathrm{V_{total}} \mathrm{C_{p,r}} \left(T_{\mathrm{r,i}} - T_{\mathrm{o}}\right) \tag{2}$$

where $\mathrm{F_r}$ is recovery factor, ρ is density, $\mathrm{V_{total}}$ is total volume, $\mathrm{C_r}$ is specific heat capacity, $T_{\mathrm{r,i}}$ is initial fluid temperature, and T_{o} is shut-in temperature.

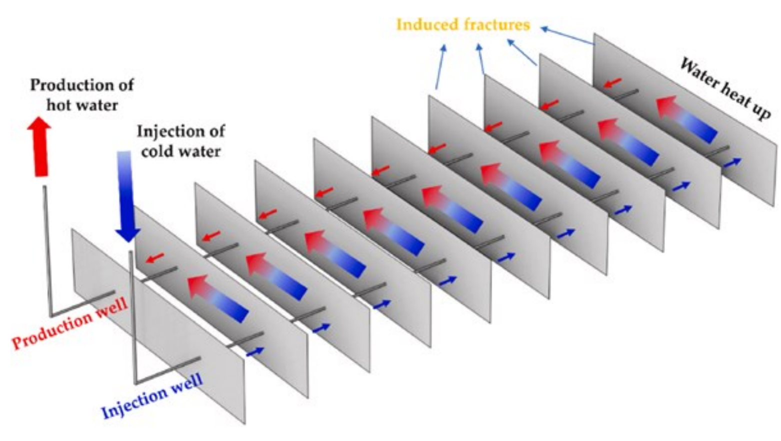

Figure 1: Diagram of multifractured horizontal well for HDR energy production (Zhang & Taleghani, 2024)

For hydrothermal systems in permeable formations, recovery factors can be estimated using known methods. Similar techniques are employed by Sanyal and Butler (2005) for HDR designs relying on circulating water through natural or artificial fracture network in otherwise impermeable formation. They estimated that 34-47% of heat can be recovered from a stimulated volume, while Tester (2006) assumed recovery factor of 2-20% of the total heat in place. Potential generation capacity was calculated in a 1 km thick slice. The 2% recovery factor case effectively assumes that 5% of the total volume is stimulated.

In our approach we will not use any empirical estimations of the recovery factor. Instead, we will use a simple HDR model described in (Ricks, et. al., 2022) and use models described by Gringarten and Witherspoon (1973) to estimate rate of heat extraction by circulating water between injector and producer wells through the system of parallel fractures (Figure 1). We will assume that the length of horizontal section is 2,000 meters and effective area of each fracture to be 72,000 m^2.

Table 1: Parameters for power output per doublet system

Parameter	Value	Unit
η_{th}	0.1	-
$\dot{m_w}$	100	kg/s
$C_{p,w}$	4,176	$\frac{J}{kg \cdot K}$
$C_{\mathrm{p,r}}$	1,050	$\frac{J}{kg \cdot K}$
k_{r}	2.5	$\frac{W}{m \cdot K}$
ρ_{r}	2,650	kg
ρ_f	976	kg/m^3
T_{r}	180	°C
T_{inj}	80	°C
$\mathrm{A_f}$	72,000	m^2
w_f	0.4	mm

Assuming 100 kg/s of flow is evenly split across 100 fractures spaced 20 meters apart, the power output over time from a binary system with 10% efficiency is given by Equation 3. It is adapted from Tester & Smith (1977) to account for flow into both directions of a bi-wing fracture and displacement of fluid initially within the fracture. We assume that fluid is recovered at the surface at the same rate at which it was injected. A more rigorous model would account for temperature dependent material properties of water.

$$P_{\mathrm{plant}}(t) = \boldsymbol{\eta_{th}} \cdot \dot{m_w} \cdot C_{p,w} \cdot \left(T_{\mathrm{r}} - T_{\mathrm{inj}}\right) \cdot \left(1 - erfc\left(\sqrt{\frac{k_{\mathrm{r}} \cdot C_{\mathrm{p,r}} \cdot \rho_{\mathrm{r}}}{t - t_\ell}} \cdot \frac{n_f \cdot \mathrm{A_f}}{2\dot{m_w} \cdot C_{p,w}}\right) \mathcal{H}(\mathrm{t} - \mathrm{t}_\ell)\right) \tag{3}$$

where $\boldsymbol{\eta_{th}}$ is cycle thermal efficiency, $\dot{m_w}$ is mass flow rate, $C_{p,w}$ is water heat capacity at T_{inj}, T_{r} is formation temperature, T_{inj} is injection temperature, k_{r} is formation thermal conductivity, $C_{\mathrm{p,r}}$ is formation specific heat capacity, ρ_{r} is formation density, t is time, $\mathrm{A_f}$ is area of a single fracture, n_f is number of fractures, t_ℓ is lag time, which describes the volume of fluid in all fractures divided by the volumetric flowrate through all fractures or:

$$t_\ell = \frac{\rho_f \cdot w_f \cdot A_f \cdot n_f}{\dot{m_w}} \tag{4}$$

where ρ_f is fluid density at T_{inj} and w_f is the width of each fracture. Injection pumps are nessecary to offset wellbore and fracture friction and to maintaing desired flowrate. Differential pressure across the injection pump is 8.25 MPa, and it operates at 0.85 efficiency. A parasitic term for injection pump power is calculated as:

$$P_{pump} = \frac{\dot{m}_w}{\rho_w \cdot \eta_{pump}} \cdot p_{diff} \tag{5}$$

Where p_{diff} is differntial pressure applied by the injection pump and η_{pump} is pump efficiency. Injection pumps are powered by the power plant. Therefore, net power output, P_{net}, can be found by:

$$P_{net} = P_{\text{plant}}(t) - P_{pump} \tag{6}$$

Figure 2 shows the effect of thermal depletion and parasitic load on net electric generation over a 30-year project life.

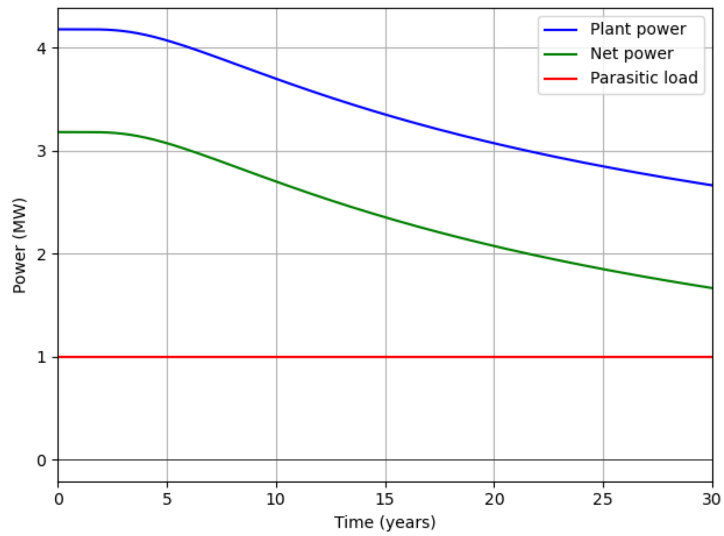

Figure 2: Estimated power decline over time

This configuration yields an estimated net production capacity of 3 MW per doublet. Each well has legs extending 2,000 m horizontally that are spaced 120m apart. The next doublet will be spaced another 120 meters away.

$$A_{\text{MW}} = \frac{2\, L_{\text{h}} \cdot d_{\text{leg}}}{P} \tag{7}$$

Where A_{MW} is area per MW of HDR net generation capacity, L_{h} is length of each horizontal leg, d_{leg} distance between each leg, and P is power delivered per doublet. With the above assumptions, the required area per MW was calculated to be 0.16 km^2/MW. This number will be used to model power generation potential of 180°C heat resource at variable depth across the United States.

In each 18 km^2 grid, only one horizon is produced for its heat resource, though deeper horizons would have superior heat resource. Two scenarios will be considered: one assuming all HDR resources are developed and another where only 30% of the land suitable for development is used for energy production. Physical models of conduction and thermal depletion were employed to estimate the cumulative energy recoverable over a 30-year plant lifespan.

3. RESULTS

Figure 3 displays the depth to 180°C in areas where it is less than 6 km deep. We removed conservation areas such as national and state parks, wilderness areas, national monuments. Mountainous regions, defined as a 200-acre grid containing a maximum slope of 15 degrees, were removed. Values are sourced from temperature, heat flow and thermal conductivity predictions by the STM (Stanford University, 2024).

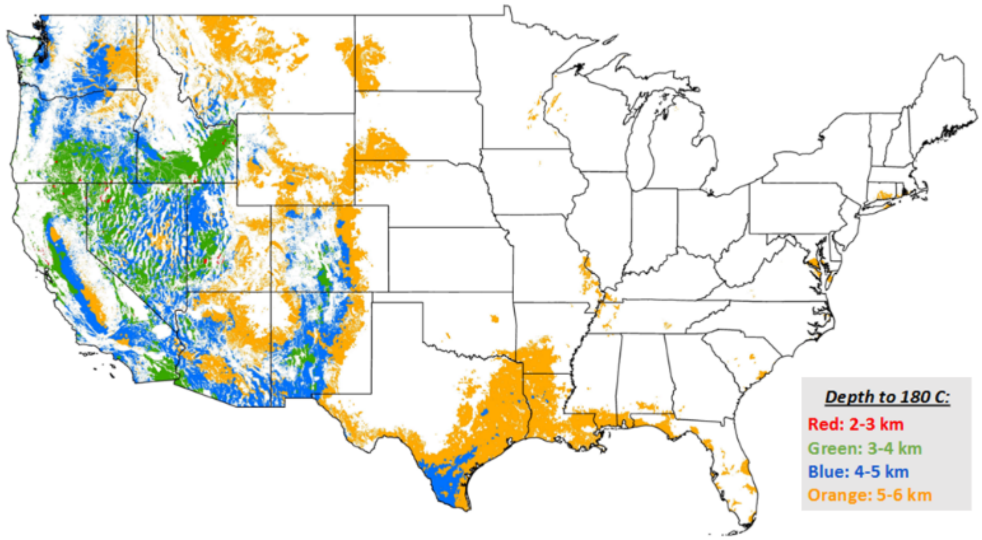

Figure 3: Depth to 180° Celsius within the L48 USA.

The bulk of geothermal potential lies in the western United States and in the Gulf Coast region. Specifically, the states with the largest HDR capacity are Texas, California, Nevada, Arizona, and New Mexico when accounting for mountainous and protected lands. Western states typically have better geothermal resources although they also host large portions of land deemed unusable for geothermal development due to social and ecological exclusions. HDR resource is sparsely accessible less than 3 km deep, highlighting that drilling deeper will be required to produce economic projects. HDR can be accessed across wide geographies, if operators are prepared to drill deep enough to reach it. The surface area where 180°C formation temperature can be reached within a depth slice is calculated. Each km^2 of land could produce 6.25 MW. Therefore, we determined the HDR power generation potential to be 13,286 GW when accounting for resource shallower than 6 km. The generation capacity potential of 180°C HDR resource is broken out across 1 km depth slices (Figure 4). Capacity in shallower slices is not included in the capacity for any deeper depth slice.

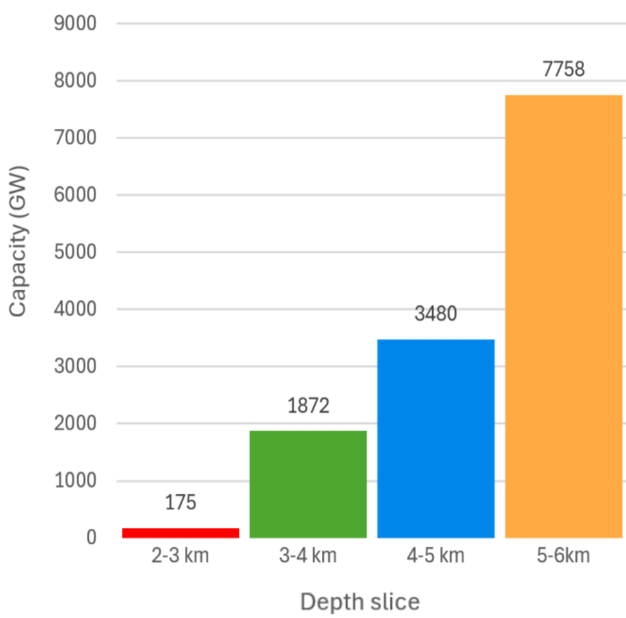

Figure 4: HDR geothermal power generation potential with depth

Our analysis builds on prior assessments of HDR capacity. If only 30% of possible HDR resource were to be developed, generation capacity would still be 3,985 GW. Figure 4 displays how potential capacity is distributed across various depth slices.

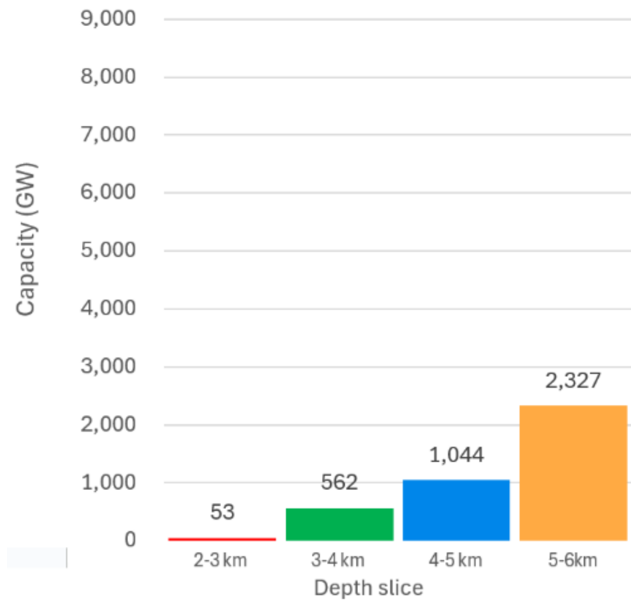

Figure 5: HDR geothermal power generation potential with depth; 30% subsurface utilization

Tester (2006) estimated that 1,249 GW could be produced, assuming a 2% recovery factor on thermal energy. Lopez et al. (2012) estimated a theoretical HDR capacity of 4,000 GW for the United States, relying on geothermal gradients informed by SMU data. Augustine (2023) updated these estimates by incorporating regional studies of the Cascades, Snake River Plain, and Basin and Range, bringing the total HDR capacity potential to 7,497 GW. Aljubran (2024a) provided an even higher theoretical capacity of 35,808 GW of HDR capacity between 1 and 7 km depths. All studies, including this one, have excluded multi-TW of energy capacity due to technical or economic infeasibility.

Significant differences lie between each study's power generation potential because they were each calibrated to a set of subsurface, surface, and economic parameters. For example, 78% of Aljubran's HDR power potential resides below 6 km. This study did not consider HDR resources deeper than 6 km due to technical and economic constraints. Aljubran also estimated that each km^2 of land, on average, could house an 11 MW facility by including resources up to 350°C, which contain a high heat density. His study targeted deeper, hotter reservoirs than are considered in this study. This study is focused primarily on the effect of depth to heat resource has on economic HDR projects.

4. DISCUSSION

Past studies have utilized the Geothermal Electricity Technology Evaluation Model (GETEM) to determine the depth at which LCOE is at a minimum (Augustine, 2011). The model operates under the assumption that drilling costs increase, and power plant costs decrease with depth due to increased powerplant efficiency. Aljubran and Horne (2024c) calculated LCOE using Flexible Enhanced Geothermal Model (FEGM), which found projects can minimize LCOE by drilling to the deepest viable point in most regions. Their analysis determined that drilling to 7 km was optimal in 90% of the United States (Aljubran, 2024a), as deeper wells provide access to higher-temperature resources. However, drilling costs were identified as the primary driver of capital expenditure (CAPEX) increases at these depths, reflecting both the technical challenges of reaching deeper heat resources and the associated operational costs. While pump costs were included in their model, they did not significantly contribute to overall costs compared to drilling expenditures.

We calculated LCOE based on current drilling and well construction costs as well as reasonable heat-to-power conversion efficiencies. These represent market estimates of Levelized Cost of Energy (LCOE) without accounting for the benefits of scale. In practice, optimization of drilling, powerplant design and manufacturing processes will further reduce costs.

A base LCOE was established between 3-4 km with qualitative LCOE provided for other depth slices referencing this value (Table 2). At 3 km, LCOE estimates are at a minimum while growing almost exponentially with each kilometer of depth added. These estimates incorporate both capital expenditures and operational costs, reflecting the economic feasibility of HDR power generation under present-day technological conditions.

Table 2: LCOE Variance by Depth.

Depth to 180°C	Incremental LCOE ($/MWh)	Generation Capacity (GW)
2-3 km	-$5	53
3-4 km	Base	562
4-5 km	+$5	1,044
5-6 km	+$35	2,327

Our analysis identifies a trend of increasing LCOE with depth. In shallow regions, CAPEX increases are driven primarily by drilling and completion costs. Below 5 km, high-pressure equipment is used in plant designs, so surface equipment CAPEX becomes the dominant cost driver over well CAPEX. These costs are related to the increased operating pressures required to operate deep wells. Beyond 6 km, surface equipment specification—including injection pumps, pressure exchangers, and heat exchangers—exceed technical capabilities of ‘off-the-shelf’ equipment, making such depths economically infeasible with current technologies. Existing cost models have well costs due to drilling and completion costs increasing predictively with depth, though do not significantly account for elevated surface equipment costs. Furthermore, standard oil and gas drilling rigs, which we assume for this analysis, are generally not rated to operate at the pressures and depths required for wells exceeding 6 km. Thus, 6 km represents a practical economic cutoff point for HDR geothermal development under existing conditions.

5. CONCLUSIONS

This study confirms massive HDR generation potential in USA and highlights market economics will be the limiting factor in HDR development in the United States. Shallow HDR resource enables projects with low LCOE, though these are sparsely available across the United States compared to wide-ranging availability of deep heat resource. Deeper targets will have comparatively higher costs due to CAPEX requirements to satisfy surface and subsurface constraints. Resource accessibility will be balanced by economic feasibility, and the criticality of economic thresholds with respect to depth-related resource quality and costs. HDR geothermal systems show immense promise, while cost considerations (particularly at depths exceeding 5 km) highlight the need for continued innovation in drilling, completion, and surface technology.

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