Proceedings World Geothermal Congress 2026
Calgary, Canada, June 8 – 11, 2026

Design-Aware Prospecting for Enhanced Geothermal Systems in Southwestern USA

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Keywords: EGS, Drilling and Completions, Reservoir Quality, Barriers

INTRODUCTION

The viability of geothermal energy development is strongly dependent on physical, economic, and community factors. As of 2023, key technical barriers to artificial geothermal reservoirs are solved by Enhanced Geothermal Systems (EGS), Polycrystalline Compact (PDC) drilling, Organic Rankine Cycle (ORC) thermoelectric power conversion, and induced seismicity risk mitigation methods (Gringarten et al., 1975; Brown et al., 2012; Frash et al., 2020; DOE, 2024; Horne et al., 2025; Madenova et al., 2025). Now, the challenge is to identify where to develop new power plants. The most obvious first step for prospecting is to estimate thermal gradient and then classify locations according to their resource quality. This effort was already undertaken by several groups to produce temperature maps for the United States and elsewhere (Blackwell et al., 2011; Roberts et al., 2018; Aljubran et al., 2024; Kirkby et al., 2025). The less-obvious next step is to combine this information with crustal state-of-stress (Lundstern and Zoback, 2020), proximity to high-voltage transmission infrastructure (Esri, 2025), proximity to water sources (Stanton et al., 2017), proximity to required supply chains, local power pricing, and government incentives. With this information, we can begin to estimate investment metrics such as the Levelized Cost of Electricity (LCOE), Net Present Value (NPV), and the Internal Rate of Return (IRR). However, these parameters also depend on the EGS reservoir design which controls its cost and performance forecast. We complete this task using Geothermal Design Tool (GeoDT) to obtain design-aware prospecting maps.

1 GEOTHERMAL RESERVOIR DESIGN

Based on currently available technologies and existing supply chains, our work points to sand-propped multi-stage EGS as the most promising solution for low-cost scalable geothermal development. However, conventional geothermal will outperform EGS when the resource can deliver high-temperature water at economic flow rates that do not require reservoir stimulation. Therefore, we treat EGS as a risk mitigation strategy for resource development when geothermal wells fail to produce at economic rates. Following this line of thinking, we use Monte-Carlo ensembles to quantify performance uncertainty and its impact on development risk. Specifically, we use Geothermal Design Tool (GeoDT; Frash, 2025) with a multi-well multi-bench development plan that factors in the effects of geothermal gradient, in-situ stress, proppant performance, well spacing, lateral length, fracture spacing, and flow rate (Figure 1). The goal in this approach is to confront the reality of what can be done today and what the associated system performance would be. Field data from Blue Mountain Nevada, Fenton Hill New Mexico, Platteville Colorado, and Milford Utah provide some assurance that the performance we forecast is reasonable and achievable. However, we still lack field data to validate thermal decline over time because no project has yet operated at a high enough rate or long enough duration to see this decline in actual. Thermal decline is therefore validated using an analytical model (Gringarten et al., 1975).

2 OPTIMAL FLOW RATE

One of the most important aspects of EGS design stems from the fact that hot dry rock is thermal-conduction-limited. Lacking natural permeability to facilitate fluid convection, all heat extracted from the reservoir requires injection of a low-temperature fluid that absorbs heat by cooling the rock. The produced power depends on the surface area of this underground heat exchanger and the flow rate of the fluid through the reservoir (Figure 1). At a low flow rate, the fluid will cool excessively as it rises up the production wells since it is traveling through colder rock than the deeper resource. At a moderate flow rate, high temperatures will make it to the surface and circulation pressures will remain low and manageable. At high flow rate, the reservoir cools down faster which causes the produced fluid temperature to decline and the circulation pressures to rise over time as the fluid viscosity increases. At excessive flow rates, the fluid cools the rock but does not have time to heat up before coming back to the surface and the circulation pressure will also become extreme. Every EGS design has a single optimal flow rate that produces maximum net power at the lowest cost and for a suitably long duration, typically targeting 15 to 30 years. Key factors controlling this optimal flow rate include well cost, facility cost, pumping losses, well size, surface area, in-situ stress, and resource quality.

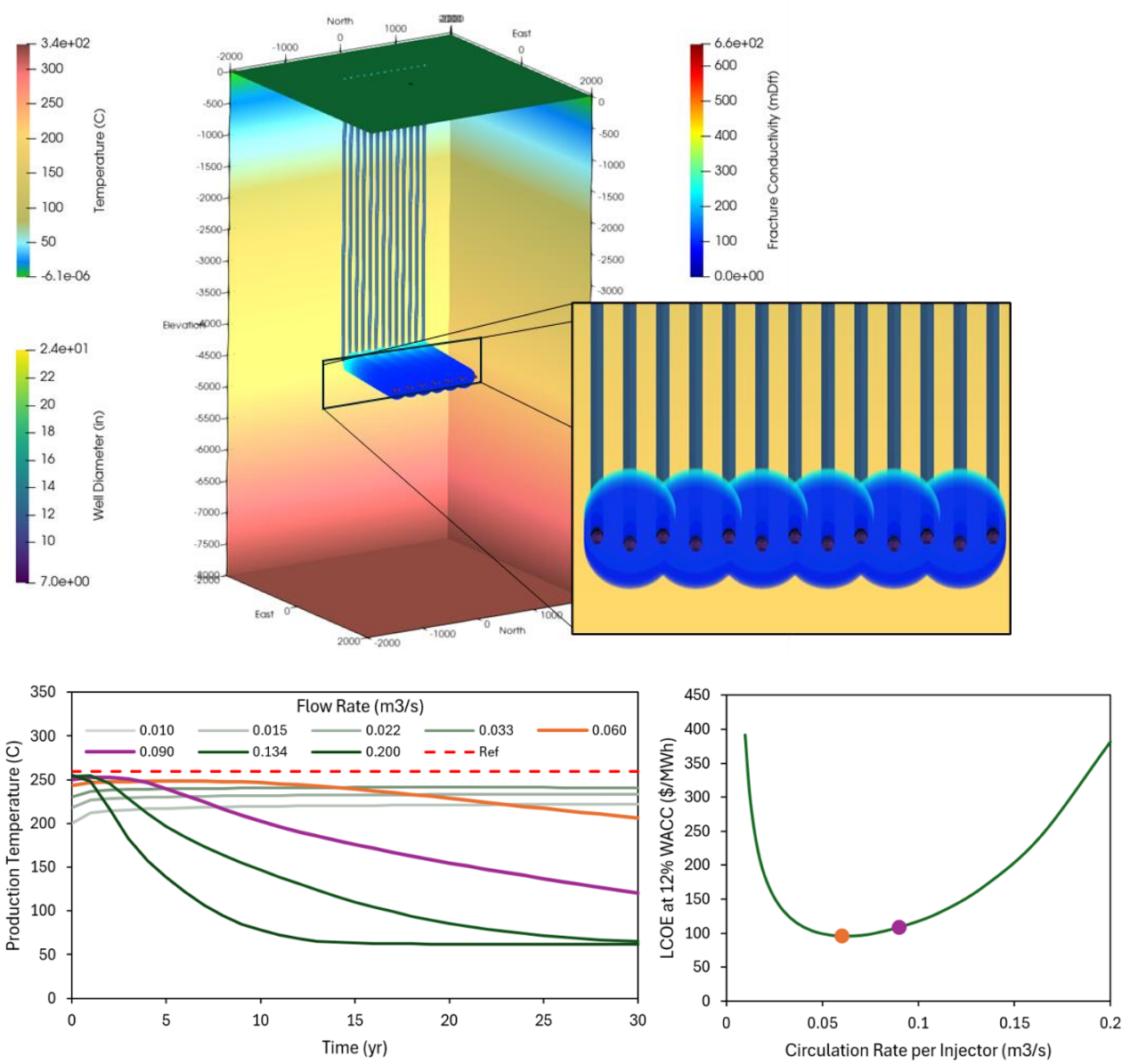


Figure 1. (Top) Scalable EGS reservoir design with directionally-drilled wells. Design variables include flow rate, well depth, well spacing, geothermal gradient, in-situ stress regime, rock properties, proppant properties, stimulation design, well diameter, number of wells, and surface working pressures. (Bottom) Effect of circulation rate on EGS performance with 9 wells (5 producers) cased with a 7" production liner. Flow has a heterogeneity factor of 0.75 through 1500 m laterals with 8 m facture spacing and 150 m well spacing. Fluid loss is estimated at 10% and weighted average cost of capital is 12%. Costs include drilling, casing, stimulation, facilities, site preparation, pumping losses, grid connection, and seismic risk. The orange line highlights the optimal flow rate for minimum LCOE. The magenta line highlights the optimal rate for IRR. Every EGS design will have its own optimal flow rate range that produces the highest assurance of a return on investment.

3 OPTIMAL DEPTH AND THERMAL GRADIENT

The mere basics of EGS prospecting is to find hot rock at shallow depth but economics reveal something much more interesting, where lower quality resources can be more attractive. The key is the fact that rock temperature generally increases with depth and that thermoelectric energy conversion efficiency increases with temperature. This means that EGS will perform better when drilling to a temperature, rather than a depth (Figure 2). Current technologies limit temperature to 300 °C (572 °F) and depth to around 7 km (23,000 ft) when the bottom hole size is 220 mm (8-5/8") when using a land-based rig. The result is that economic LCOE at $120/MWh can be achieved if the geothermal gradient is at least 45 °C/km in a normally faulted stress regime. This result holds when uncertainty in the reservoir properties is included (Frash and Lines, 2025). Thus, a 45 °C thermal gradient is a useful threshold for prospecting and drilling to temperatures above 200 °C is an economic design requirement.

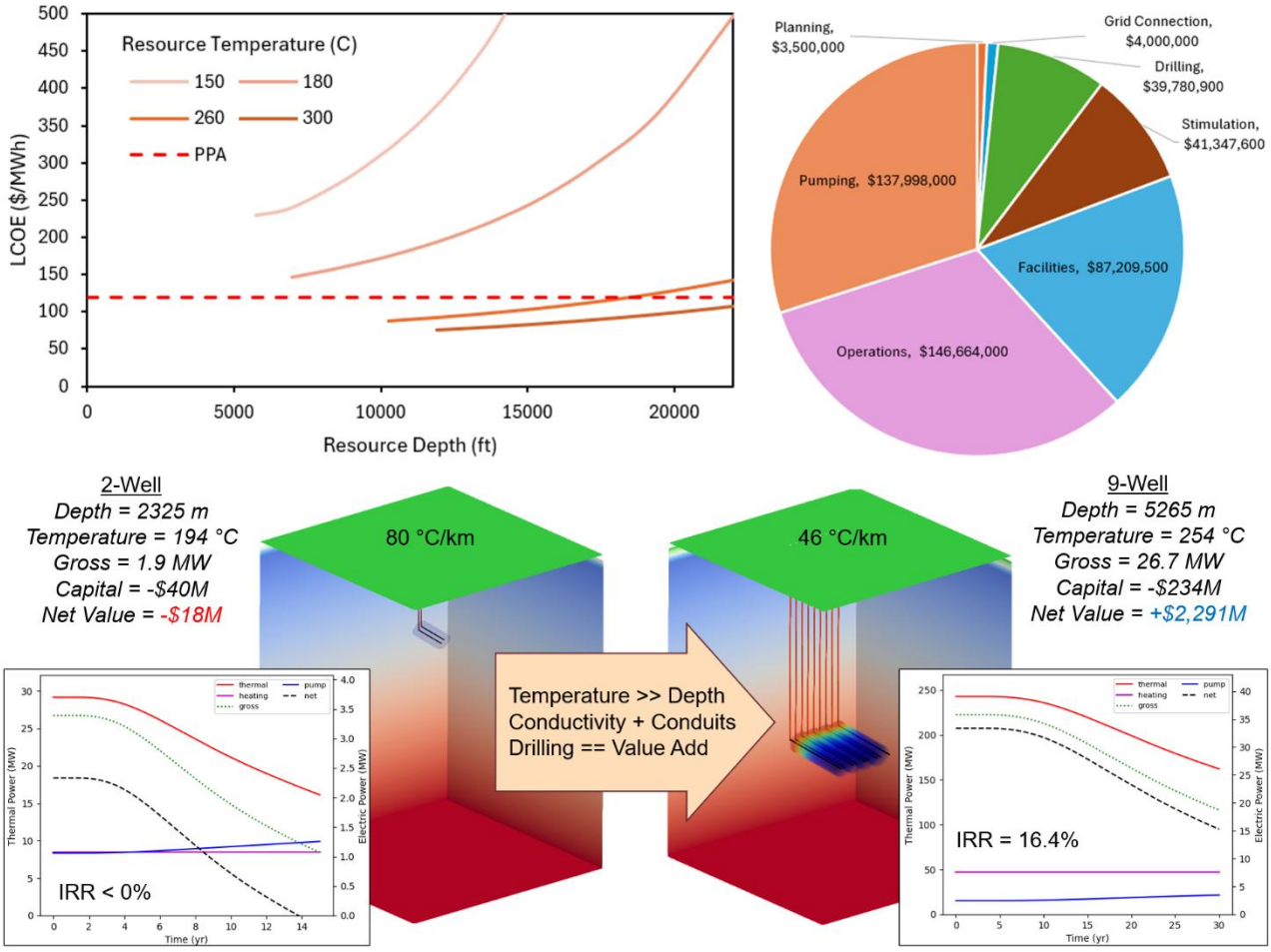


Figure 2. (Top Left) Levelized cost of electricity at 12% cost of capital as a function of resource depth and temperature. (Top Right) Final 30 yr project costs with 3% inflation for 9 wells drilled into a 260 °C resource with a 55 °C/km thermal gradient. Drilling cost is important, but less than 9% of the total project cost with depth being 4.5 km (14,800 ft). The cost of drilling deeper is exponential, but easily outweighed by the benefit of higher temperatures. (Bottom) Pilot scale 2 well project of the type used at Blue Mountain Nevada and Milford Utah and scale-up to a deeper 9 well commercial EGS in a lower quality resource. Design aware prospecting considers much more than the geothermal gradient when evaluating resource potential.

4 ECONOMY OF SCALE

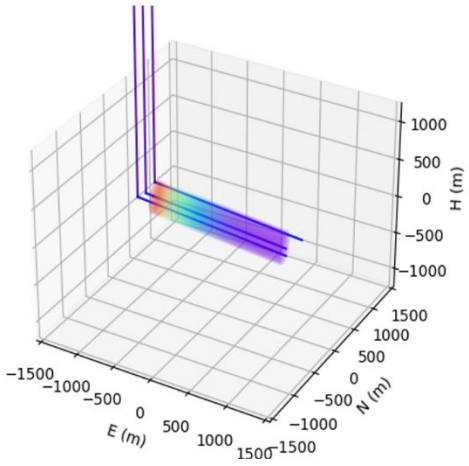
Increasing the target temperature (i.e., depth), the number of wells, and the diameter of wells improves the LCOE for a given resource (Figure 2). Drilling more wells also helps to assure against injection induced seismicity by increasing control of the perturbed reservoir volume. In general, the minimum viable project size tends to be a 3 well EGS system that produces at least 5 MW per production well. Smaller systems incur too much capital cost for too little production because of the penalty of lower temperatures in shallower wells. When drilled using one rig, an optimal unit size is in the range of 40 MW to 200 MW. Surging and choking production allows flow rate to range from -30% to +60% around the optimum for extended periods of time with a minor penalty on economic metrics (e.g., +/- 15% LCOE). Drilling more wells per campaign brings lower costs per well through learning and crew experience. Staged and multi-bench drilling can be used to get higher plateau production rates and better surface equipment utilization. Additionally, larger projects improve market leverage for tool development that would benefit the industry toward the goal of reduced cost of electricity and increased energy production. New tools are needed to enable larger diameter wells.

5 PROSPECT MAPPING

Focusing on the 3 well minimum viable EGS design, we use GeoDT to develop a multi-dimensional lookup table that brings together various site factors and design optimization for improved prospecting (Figure 3). We do not seek the shallowest heat, instead we seek the lowest LCOE or the highest IRR. Similar maps can be produced as a function of project scale, from 10 MW to 10,000 MW. When combined with the reservoir design, we estimate subsurface land use energy density at 4 to 14 MW/m^2, with higher density achieved by higher target reservoir

temperatures. This will increase when resources are developed in multiple benches. Land surface use is less than 10% of this value.

Geothermal Gradient °C/km	Anderson's Aphi Coefficient 0-1 = Normal, 1-2 = Strike-Slip, 2-3 = Thrust				
	0.25	0.75	1.25	1.75	2.25
0.025	217 $/MWh -170 $M 9 km	469 $/MWh -168 $M 9 km	404 $/MWh -163 $M 9 km	1455 $/MWh -169 $M 9 km	16032 $/MWh -165 $M 9 km
0.035	172 $/MWh -112 $M 7 km	180 $/MWh -116 $M 7 km	195 $/MWh -111 $M 7 km	325 $/MWh -118 $M 7 km	732 $/MWh -121 $M 7 km
0.045	148 $/MWh -94 $M 6 km	132 $/MWh -96 $M 6 km	150 $/MWh -93 $M 6 km	187 $/MWh -94 $M 6 km	257 $/MWh -95 $M 6 km
0.055	109 $/MWh -82 $M 4 km	120 $/MWh -84 $M 5 km	130 $/MWh -84 $M 5 km	168 $/MWh -84 $M 5 km	181 $/MWh -85 $M 5 km
0.065	107 $/MWh -79 $M 4 km	114 $/MWh -79 $M 4 km	121 $/MWh -79 $M 4 km	142 $/MWh -79 $M 4 km	150 $/MWh -79 $M 4 km
0.075	109 $/MWh -75 $M 3 km	113 $/MWh -76 $M 3 km	109 $/MWh -76 $M 3 km	123 $/MWh -76 $M 3 km	127 $/MWh -76 $M 3 km



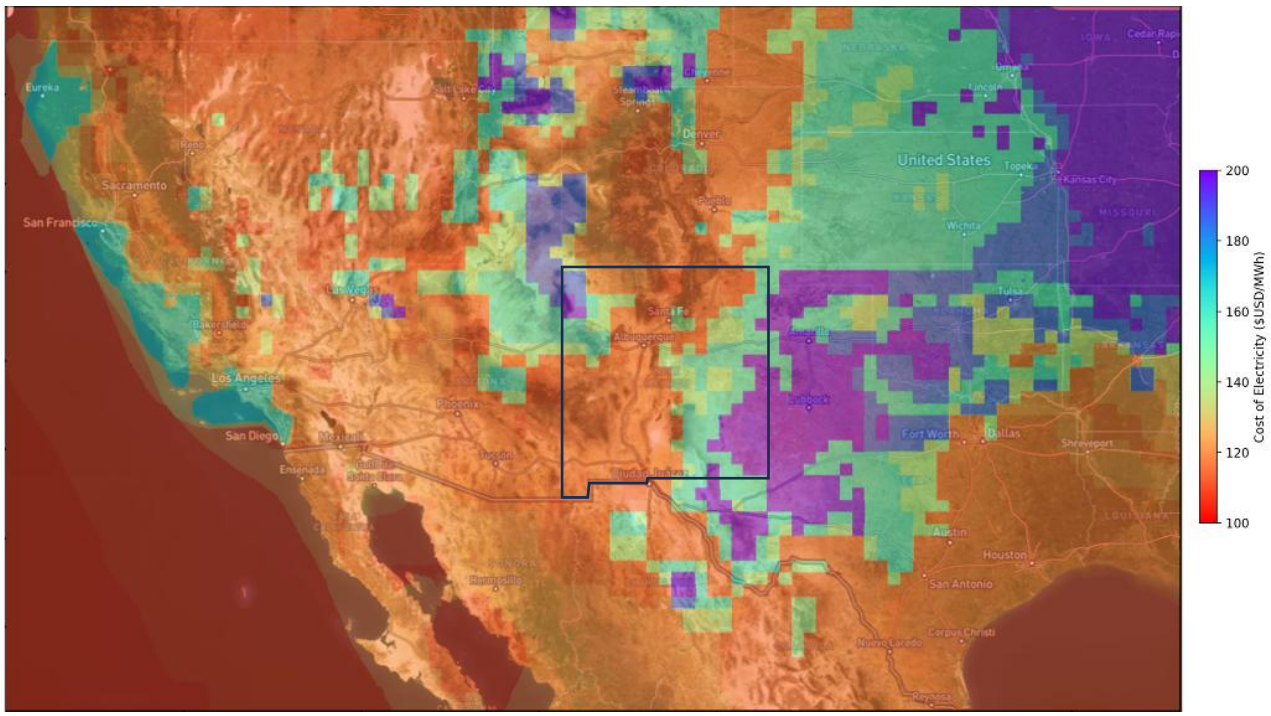


Figure 3. (Top) Lookup table combining geothermal gradient with in-situ stress conditions to get design-aware geothermal prospectivity from site characteristics. The same workflow can include effects such as proximity to the electric grid. This analysis assumes a reservoir temperature of 250 °C. (Top Right) A 3 well EGS design for reference. (Bottom) Map of LCOE for the Southwestern United States which factors in geothermal gradient and the in-situ stress regime. Costs include drilling, stimulation, facilities, pumping, and operations with a 12% cost of capital. Base data was interpreted from GeoMap Beta with modifications to correct for cold basins (e.g., the Permian Basin).

6 CONCLUSIONS

This document presents a work in progress where the goal is prospecting for EGS using more than basic temperature at depth maps. Our analysis reveals that geothermal gradients of 45 °C/km or higher are adequate for economic power production. Higher geothermal gradients do bring some benefit, but the key is being able to reach temperatures of 250 °C or more within 7 km of drilling depth so that currently available technologies can be used. Drilling is only about 10% of the total project cost, even for deep wells, with a similar cost for stimulation and a higher cost in the surface facilities (e.g., turbomachinery, transformers, and chillers). Pumping parasitic losses are a major component of the operational costs with losses of around 30% relative to gross production being observed in the field. Increased well sizes, improved fracture conductivity, and high-density fracture stimulation are key to reducing this pumping parasitic loss in EGS. Some of these improvements are possible today with adequate design, but larger wells that target higher temperatures will require more tool development. We hope that by presenting these results we can help show the value of investment into deep high-temperature

large-diameter tool development alongside the immense potential of EGS with currently available tools, as based on current cost estimates.

Acknowledgements

This work is supported by Department of Energy (DOE) Basic Energy Sciences LANLE3W1. Additional support was provided by the New Mexico Small Business Assistance program from the State of New Mexico which enables Los Alamos National Laboratory to provide R&D support to small businesses. Core capabilities enabling this effort were supported by Los Alamos National Laboratory's Directed Research and Development – Exploratory Research program under LDRD-ER-20220175ER and the DOE Geothermal Technologies Office's (GTO's) Geothermal Limitless Approach to Drilling Efficiencies (GLADE; DE-EE0010444) led by Oxy, Inc. We are grateful for this funding provided by DOE and LANL. The views expressed herein do not necessarily represent the views of the U.S. Department of Energy or the United States Government.

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