Deployment of Enhanced Geothermal System technology leads to rapid cost reductions and performance improvements

Jack Norbeck[a], Christian Gradl[a], and Timothy Latimer[a]

[a]Fervo Energy

910 Louisiana St., Ste. 4400, Houston, Texas, USA 77002

Corresponding Author: Jack H. Norbeck

Corresponding Author Email: jack.norbeck@fervoenergy.com

This manuscript is a non-peer reviewed preprint submitted to EarthArXiv.

RESEARCH ARTICLE

Deployment of Enhanced Geothermal System technology leads to rapid cost reductions and performance improvements

Received Date
Accepted Date

DOI: 00.0000/xxxxxxxxxx

Jack Norbeck[a], Christian Gradl[a], and Timothy Latimer[a]

Following successful production testing of the world's first horizontal well enhanced geothermal system in 2023, continued deployment and optimization of the technology across two commercial projects has resulted in significant cost reductions and performance improvements. In this paper, we present field results and updates from Fervo Energy's enhanced geothermal system projects in Nevada and Utah.

The Project Red system, located in northern Nevada, was fully commissioned over the summer of 2023 and began sending power to the grid in October 2023. The initial production temperature of the system came online at 341.7 °F, over 5 °F hotter than observed during the well testing phase several months before final commissioning. As of September 2024, the system is producing at 346.8 °F, confirming that no thermal decline has occurred over the first 6,200 hours of commercial operations.

The Project Cape site is located in southern Utah. The drilling campaign at Project Cape began in June 2023 with a deep vertical appraisal well drilled to a depth of 9,824 ft at which a maximum recorded temperature of 444 °F confirmed the presence of a high-quality geothermal resource. Following the initial appraisal well, a total of 15 horizontal wells have been drilled as of September 2024. We have achieved successful drilling results while drilling at up to 434 °F along the lateral. We have been able to demonstrate a 100% drilling success rate, as measured across various metrics including predicted vs. measured bottomhole temperature, target vs. actual total depth, and target vs. actual drilling cost.

A pad of three horizontal wells was stimulated successfully using a multistage, plug-and-perforate method. A total of 80 treatment stages were completed across the three wells. All stages were pumped at treating pressure below the rated design pressure and no screenouts occurred, giving a 100% completion success rate. In addition, 95% of the stages were completed with the designed proppant loading volumes. A 30-day production test was performed at the three-well pad in July and August 2024. The first production well at the Cape site achieved a peak output of over 12 MW and a sustained output of 8-10 MW. Production temperatures increased throughout the 30-day test with no indication of thermal decline. The maximum measured temperature of 383 °F meets the design criteria for the Cape Station organic Rankine cycle power plant.

In a first for enhanced geothermal system development, we have drilled an 8-well pad that targets two different formation benches, significantly increasing the power density and minimizing the surface disturbance at the site. A heat in place analysis indicates that by using a multi-bench development strategy at the Cape resource, the power capacity density is 9.1 MW per km^3, 5-10 times larger than previous estimates for EGS technology.

1 Introduction

Geothermal energy has been identified as a critical resource for meeting global decarbonization efforts due to its always-on, firm, weather independent nature as well as its widespread availability globally (Sepulveda et al. 2018; Ricks, Norbeck, and Jenkins 2022). Horizontal drilling and multistage completions have become the dominant methods for unconventional oil and gas development, and these technologies are now poised to unlock a paradigm shift in geothermal as well. Enhanced geothermal system (EGS) technology expands the resource potential beyond hydrothermal areas, significantly increasing the total size of geothermal resources (DOE 2019; Augustine et al. 2022). In the US alone, the Department of Energy estimates that over 100 GW

[a] *Fervo Energy, 910 Louisiana St., Ste. 4400, Houston, Texas, USA 77002*

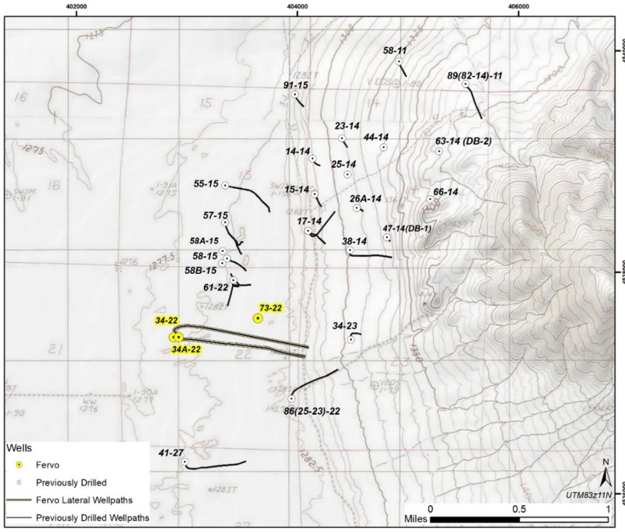

Fig. 1 Site map of the Project Red site.

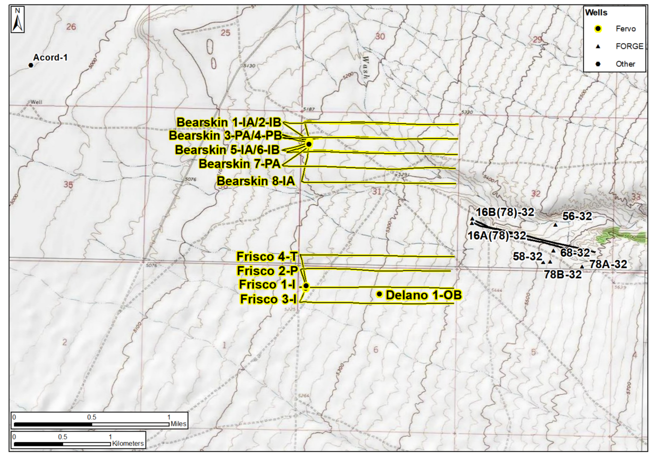

Fig. 2 Site map of the Project Cape site.

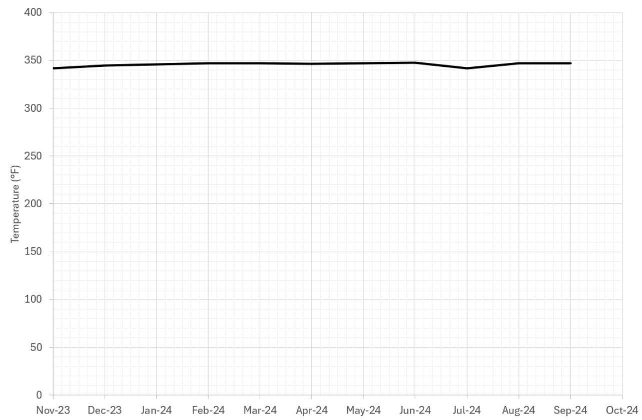

Fig. 3 Production temperature history of Production Well 34-22 at Project Red. The Project Red system has been under active commercial operations since October 31, 2023. Since coming online, the system has not experienced any thermal decline and continues to meet performance targets. The slight reduction in temperature in July 2024 is related to a downtime event and is not indicative of reservoir thermal decline.

of EGS resources will be economically recoverable by 2050 (DOE 2019). Moreover, in contrast to other emerging clean energy technologies, EGS has the advantage of being able to leverage existing geothermal, oil, and gas supply chains and technology, and is therefore able to be deployed at scale immediately. In their capacity expansion modeling, Ricks et al. (2024) found that if at least 500 MW of EGS is installed by 2030, then the compounding benefit of deployment-led learning curve cost reductions will likely result in EGS out-competing other firm energy sources in total installed capacity by 2050.

Fervo Energy has developed EGS projects across multiple project sites in different states and in areas with different geologies. Here, we present recent field results and updates from two projects (Norbeck, Latimer, and Gradl 2023; Fercho, Norbeck, and E. 2023; Fercho, Matson, and E. 2024). The Project Red site is located in northern Nevada and is representative of a near-field EGS site, as it is located at the margins of the Blue Mountain geothermal field and is connected to an existing power facility (see Fig. 1). Project Cape is located in southern Utah and is classified as a greenfield EGS site, where there are no existing geothermal facilities (see Fig. 2). Cape is located strategically adjacent to the Utah FORGE site, a Department of Energy project to test and validate EGS technology.

2 Project Red Results

Final commissioning of the Project Red system and tie-in with the existing Blue Mountain power plant occurred in October 2023. Geothermal fluid began flowing to the plant and the system began generating electricity on October 31, 2023. Since that time, the system has been operated commercially for over 6,200 hours. Successful commissioning of Project Red has confirmed that all of the key technical challenges related to EGS development - including drilling horizontal wells in high-temperature, hard rock formations, stimulating the reservoir to enhance permeability, and successfully creating a high-conductivity hydraulic connection between injection and production wells - have been retired. The primary risk that remains is related to understanding the long-term thermal longevity of the system.

As shown in Fig. 3, the Production Well 34-22 came online initially producing fluid at approximately 341 °F. Prior to starting production, the reservoir continued to heat up following the drilling and completions process, as the initial production temperature was over 5 °F hotter than the maximum flowing temperature measured during the well testing phase 6 months earlier. The well then continued to gradually heat up as expected due to near-wellbore heating effects. A steady flowing temperature of approximately 347 °F was ultimately achieved, and as of September 2024 the system has shown no evidence for thermal decline.

The lack of thermal decline is in-line with analytical and numerical modeling forecasts for horizontal well EGS systems, which are characterized by an initial flow regime with no thermal decline. The strong thermal performance at Project Red indicates that the subsurface formation that was created during the stimulation process has sufficient heat transfer surface area to support long-term thermal sustainability.

3 Project Cape Results

Project Cape builds upon the success and lessons learned from Project Red, with significantly more ambitious drilling, completions, and production design targets. The development strategy at Cape has been designed to create a step-change in project economics over Red, and generally involves drilling to deeper depths, targeting hotter reservoir temperatures, drilling longer lateral lengths, and achieving higher flow rates. Here, we present an overview of the drilling, completions, well testing, and reservoir characterization results from the initial phase of the development campaign (El-Sadi et al. 2024).

3.1 Drilling Results

A typical cross-section of the Cape wellfield is shown in Fig. 4. The wellfield design at Cape is driven predominantly by two factors: 1) we are targeting the Granitic Basement formation for development to leverage the high level of derisking that has already been achieved through previous work at the Utah FORGE project, and 2) we are targeting producing geothermal fluid at 390 °F to achieve optimal power conversion efficiency with modern organic Rankine cycle (ORC) geothermal power plant technology. These design constraints require targeting formation depths of approximately 8,000 ft to 9,000 ft true vertical depth.

The first well drilled at Cape was Delano 1-OB, designed as a vertical observation well. The purpose of this well was to confirm the temperature gradient at the greenfield site, confirm the lithologic structure of the subsurface, and to host permanent and temporary data acquisition equipment. The well was drilled successfully to a depth of 9,824 ft. Permanent distributed fiber optic sensing equipment was installed behind the casing. Both distributed acoustic sensing (DAS) and distributed temperature sensing (DTS) fibers were installed to enable real-time temperature and seismic monitoring. In addition, a permanent downhole pressure and temperature gauge was installed behind casing at a depth of 8,365 ft. Using the DTS cable, the maximum recorded temperature was measured as 444 °F, confirming a high-quality EGS resource. The temperature gauge provided secondary confirmation of the formation temperature.

The geologic and temperature data from Delano 1-OB was used to finalize the design of the first three horizontal wells at Cape. These wells were drilled from a single pad called Frisco and formed a triplet system, with a central production well offset by two injection wells. The wells were designed with lateral lengths of approximately 4,700 ft and targeted an average temperature of 395 °F. In comparison to Red, the laterals are over 1,700 ft longer and the maximum formation temperature is over 50 °F higher.

Since the drilling campaign began in June 2023, we have drilled 14 horizontal wells at Cape. The drilling performance has continued to improve throughout the campaign. Compared to Red, where the two horizontal wells were drilled in 71 and 58 days, respectively, the first horizontal well at Cape was drilled in 35 days. Successful implementation of drill bit optimization, drilling fluids optimization, and well construction design optimization, more recent wells have been drilled in under 20 days.

The reduction in drilling days along with other supply chain and engineering improvements have resulted in significant well-over-well drilling cost reductions. In Fig. 5, we show a comparison of the budgeted drilling costs (called authorization for expenditure or AFE) to the actual incurred costs over the first 14 horizontal wells at Cape. The drilling costs have come in significantly under budget across this initial drilling campaign. In addition, the measured temperatures have met or exceeded the predicted temperatures (see Fig. 6). Based on both of these economic and technical metrics, the Cape drilling campaign has achieved a 100% drilling success rate.

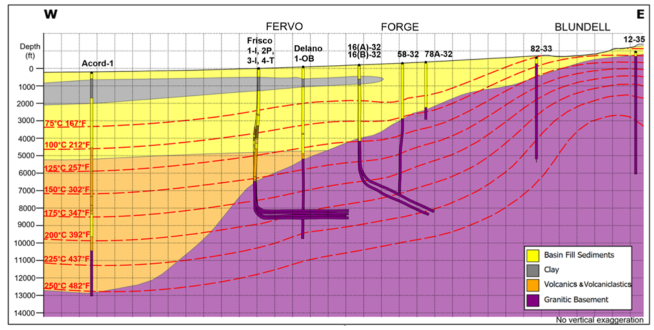

Fig. 4 Cross-section view of the Project Cape resource. The red dashed lines indicate temperature isotherms in the subsurface. The target play concept is to develop the Granitic Basement formation.

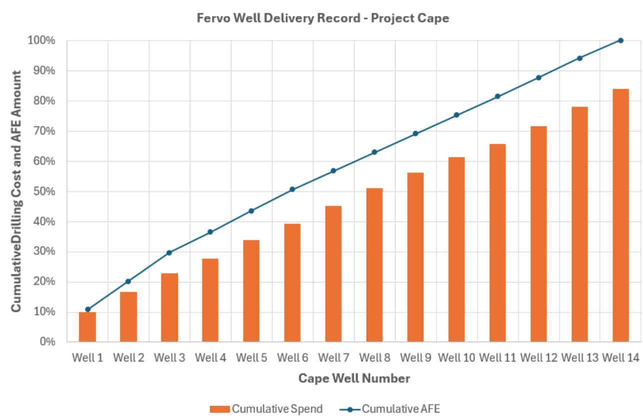

Fig. 5 Comparison of the cumulative authorization for expenditures (AFE) and the actual drilling costs for the horizontal drilling program at Cape. The project has exhibited 100% drilling success rate based on the metric of budget vs. actual drilling costs.

3.2 Stimulation Results

The first batch of completions at Cape commenced once the drilling rig was fully moved off the well pad. The initial completions batch consisted of 80 individual stages in the cased and cemented horizontal sections of 3 wells.

The completion design at Cape is built upon the highly successful stimulation design at Red. Leveraging the extensive subsurface data sets across both the Fervo and Utah FORGE sites and incorporating many lessons from project Red, Cape's completion design was optimized for highest project returns. The most significant changes in well completion design from Red to Cape were the increase in average stimulated lateral length from 3,000 ft at

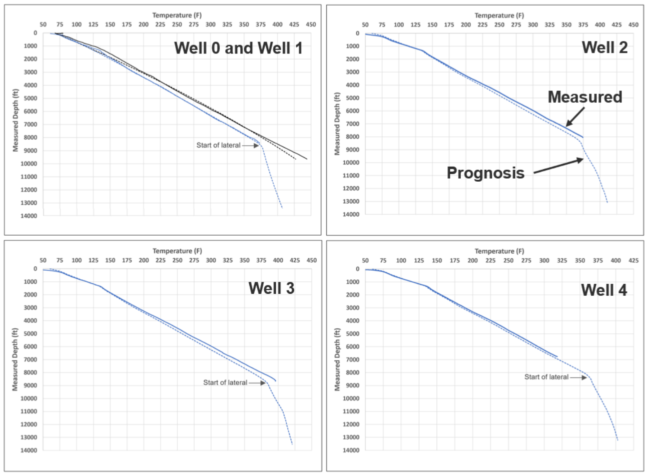

Fig. 6 Comparison of predicted temperature profiles prior to drilling to actual measured temperature profiles for the first five wells drilled at Cape. Each of the wells met or exceeded the target maximum bottomhole temperature, demonstrating minimal geologic risk.

Red to 4,700 ft at Cape and a higher intensity stimulation design when measured in gal/ft of stimulation fluid and lbs/ft of proppant loading.

Zonal isolation was achieved through a combination of the external cement sheath of the 7” casing and sequentially installed internal stimulation plugs. A combination of composite stimulation plugs with an aluminum mandrel and a newly developed fully composite stimulation plug were utilized. The fully composite stimulation plug exhibited improved drillabillity, resulting in a drill-out time improvement of approximately 50% compared to plugs with a higher metal content.

Out of 80 stages, only one stage exhibited signs of a potential plug leak during the stimulation treatment. This excellent reliability, despite maximum formation temperatures that were 50 °F higher than at project Red, again confirms the suitability of composite plugs as a zonal isolation device in EGS wells.

All 3 wells at Cape were stimulated from the same well pad, allowing for significantly improved operational efficiencies compared to traditional geothermal developments. Fervo also introduced zipper operations to geothermal stimulation, where sequential stages pumped alternate between wells. This has contributed to significant operational efficiency improvements and reduction in non-productive time in unconventional oil and gas completions.

All stages were successfully initiated and propagated with no screenouts. On 3 stages out of 80, a combination of treatment pressure characteristics and operations considerations resulted in less than the the planned proppant volume being placed in the formation 7. Average treatment pressures for 80% of stages was between 7000 psi and 9000 psi (see Fig. 8). In general, treatment pressures were highly predictable and in line with anticipated values. Based upon screenout rate, achieved proppant loading, and treating pressures, we have achieved a stimulation success rate of 95 to 100%.

Fig. 7 Design vs. actual proppant placed for each stage across a three-well pad completed with a plug-and-perforate stimulation treatment design. The designed proppant volumes were pumped on 95% of the stages.

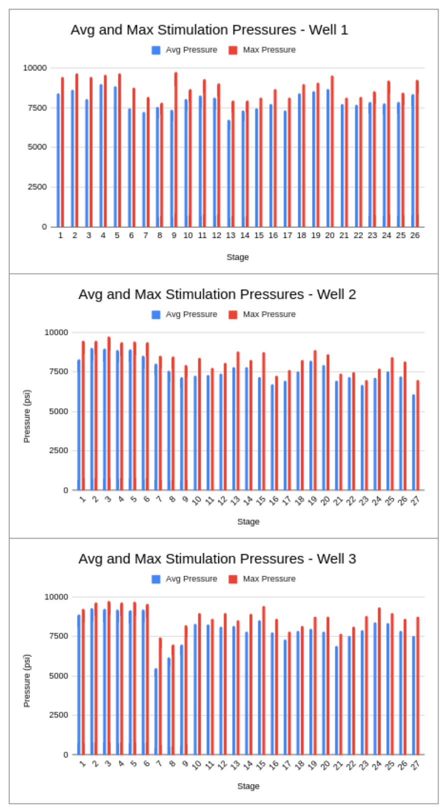

Fig. 8 Average and maximum treating pressures during stimulation operations across three wells at Cape. All stages were completed without any screenouts and treatment pressures were maintained below the maximum design pressure of 10,000 psi.

3.3 Production Well Test Results

Following successful completions operations on the Frisco well pad, we conducted a 30-day well test to evaluate the performance of the triplet well system. The well test operations consisted of injecting simultaneously into both injection wells while producing fluid from the production well. The wellhead operating conditions were set to mimic the design point operating conditions of the Cape Station power plant facility. Injection pressures were maintained between 2000 to 2300 psi and the production wellhead pressure was maintained at 300 to 350 psi. Throughout the entire test the production well sustained self-flowing conditions without the need for artificial lift.

The operating conditions of the production well were measured upstream of the flow control valve that was used to maintain backpressure on the system, therefore temperature, pressure, and flow rate were measured under single-phase conditions. These measurements provided all information necessary to directly measure the thermal energy output of the well as well as to estimate the electric power capacity of the system.

The initial production rate on Frisco 2-P was 120 kg/s, which is indicative of what the well is capable of producing (see Fig. 9). Initial transient effects resulted in the well leveling out at approximately 93 kg/s after the first day of production. Using a brine effectiveness of 94 kWe per kg/s, the electric power output is estimated at 12.0 MWe while flowing at 120 kg/s and 9.5 MWe while flowing at 93 kg/s (see Fig. 10). The initial production fluid temperature was 369 °F. Production temperature increased throughout the well test, showing no evidence for thermal decline. The maximum production fluid temperature measured during the well test was 382.9 °F, which is well within the operating range for the Cape Station power plant design (see Fig. 11). Similar to the behavior observed at Red, the production temperature is expected to increase in subsequent testing and commissioning.

The 30-day well test on the Frisco well pad has provided valuable insights into the operational performance and potential of the triplet well system. The successful management of injection pressures and the self-sustaining flow of the production well underscore the system's robust design. The ability to maintain stable production rates, accompanied by increasing fluid temperatures, indicates a strong likelihood of sustained thermal efficiency, which is crucial for the projected energy output. The first phase of production testing at Cape has confirmed the resource potential at the site as well as the technical viability of the EGS design at the site. As the testing phase progresses, the anticipation of further temperature increases suggests that the well's performance could exceed initial expectations.

3.4 Heat in Place for a Multibench EGS System

Similar to oil and gas resource characterization and reserves estimation, evaluating the potential of geothermal leases requires an integrated assessment of resource quality, geologic uncertainty, recovery mechanism, reservoir management strategy, drilling costs, and market conditions. Our resource classification approach mirrors the reserves estimation techniques and standard practices established for the oil and gas industry by the Society

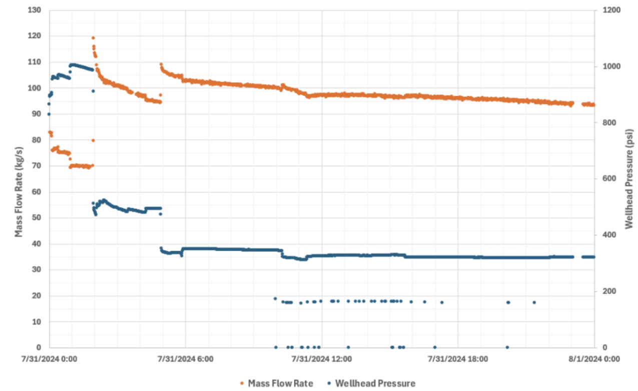

Fig. 9 Initial production data from a 30-day well test at the Cape site.

Fig. 10 Initial power production data from a 30-day well test at the Cape site. This power output is from a single production well and is estimated using the measured thermal power output and the anticipated power plant efficiency.

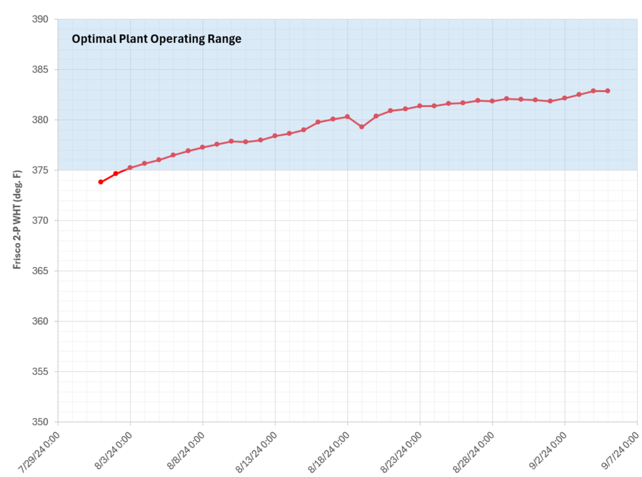

Fig. 11 Production fluid temperature throughout the 30-day well test. Temperature continued to increase as expected due to wellbore warmup effects. The test demonstrated no thermal decline or thermal short-circuit behavior.

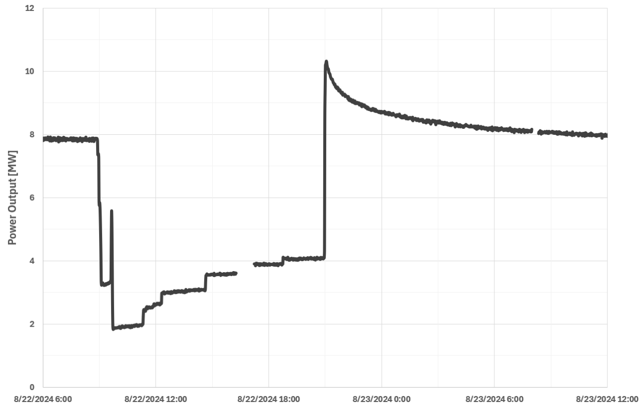

Fig. 12 Production data observed during a cycle in which the Cape system was operated in a flexible, dispatchable mode.

of Petroleum Engineers (Ross 2001), modified where necessary following geothermal reservoir engineering methodologies established by National Renewable Energy Laboratory, US Geological Survey, and geothermal industry best practices (Augustine 2016; Grant and Bixley 2011; Williams et al. 2008).

The overall resource evaluation methodology involves estimating the total heat initially in place at commercially recoverable temperature and depth conditions, applying a thermal recovery factor, and then converting thermal energy production to electric power assuming a geothermal power plant efficiency factor. Key steps in the process include offset well review, resource-specific geologic modeling, and physics based reservoir simulation production forecasts. An integrated Monte Carlo method is applied throughout each phase of the analysis in order to incorporate key uncertainties and risk factors appropriately.

For each prospect, we first perform a rigorous offset well review, literature review, and gather key geologic and/or geophysical datasets that pertain to the resource, such as seismic and gravity surveys. We construct a three-dimensional geologic model that is constrained with available offset well data and geophysical data. The geologic model is populated with key geologic properties such as lithology, temperature, heat capacity, fluid saturation, and rock density. In areas where deep well data is sparse, we use geostatistical methods to extrapolate key properties.

For the purposes of reserves estimation, the most influential property in the geologic model is the distribution of reservoir temperature. We compiled a proprietary database of deep wells (including both oil and gas and geothermal wells) with conductive temperature gradients and calculated an empirical distribution of geothermal gradients throughout the Basin and Range province. Wells located in hydrothermal upflow or outflow zones with anomalously high temperature gradients in the basin fill were removed from the analysis so as not to overestimate temperatures at depth.

We generate a set of realizations of the geologic model, where each model is tied to the deep well temperature measurements where they exist. In areas further from well control, the temperature at each point in the model is calculated using the depth to basement contact and the respective thermal gradients. Each geologic model realization represents the result of a random draw from the empirical distribution of thermal gradients. In this way, we are able to build an empirical cumulative distribution function of the resource volume that meets the criteria for reserves. These volumes are used to calculate the heat initially in place for each resource.

Heat in place is defined as:

$$H_{tot} = V\rho_r c_r \left(T_r - T_{inj}\right), \tag{1}$$

where V is the total reservoir volume, ρ_r is the density of the rock, c_r is the heat capacity of the rock and $\left(T_r - T_{inj}\right)$ is the temperature difference between the reservoir temperature and the reinjection temperature of the fluid after going through the plant. This represents the useful energy originally in place and represents the maximum amount of thermal energy that can be recovered for energy production.

The electric power capacity of the resource can then be estimated as (Grant and Bixley 2011):

$$P = \frac{\eta r H_{tot}}{\Delta t}, \tag{2}$$

where *eta* is the thermal-to-electric power conversion efficiency of the power plant, r is the thermal recovery factor, and Δt is the total project life. This represents the gross electric power capacity of a resource. This represents the average electric power capacity that can be sustained over a projects life.

At Project Cape, we have designed a multibench development campaign, where thermal energy is recovered from several discrete benches of the Granitic Basement formation (see Fig. 13). The Granitic Basement has a large thickness that presents a relatively uniform play concept in which temperature only increases with depth. This has resulted in significantly increasing the technically proven resource potential at the site. Normalizing Eq. 2 by the volume V gives the power density of a resource.

Previous department of Energy estimates for power density for EGS technology - assuming a target temperature ranging from 175 to 300 °C - have ranged from 0.7 to 0.9 MWe per km^3 (Augustine 2016; Williams et al. 2008). Assuming a project life of $\Delta t = 30$ years and a conservative thermal recovery factor of $r = 0.2$, applying Eqs. 1 and 2 to the Cape reservoir, we have determined that the power density of the resource is 8.4 MWe per km^3, demonstrating the massive upside potential that is unlocked from the multibench development strategy.

4 Concluding Remarks

The results from the Project Red and Project Cape enhanced geothermal system (EGS) projects underscore the transformative potential of applying advanced oil and gas technologies, such as horizontal drilling and multistage completions, to geothermal energy. At Project Red, the consistent production temperatures observed over the first year of commercial operations validate the long-term viability of horizontal well EGS designs. Similarly, Project Cape has demonstrated the feasibility of drilling and completing horizontal wells in high-temperature geothermal environments, achieving significant cost reductions and operational effi-

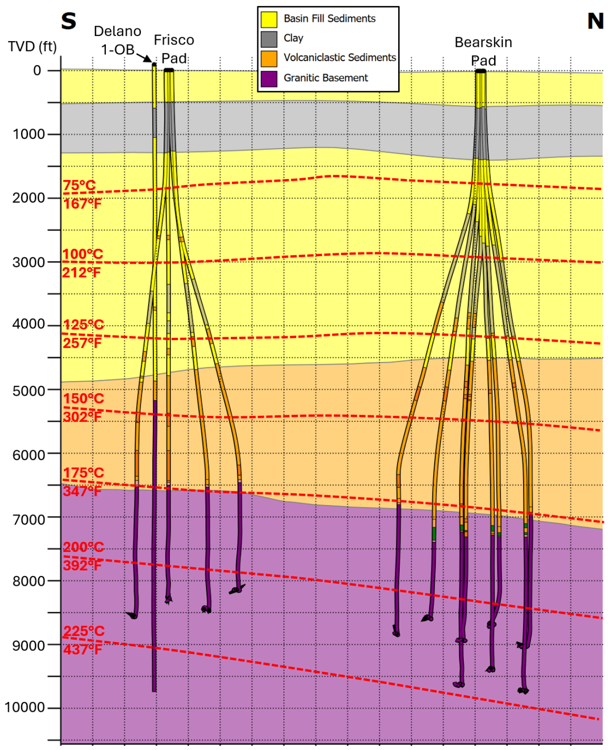

Fig. 13 North-south cross-section view of the Project Cape site. The view is looking down the lateral sections of the horizontal wells. The Bearskin pad was developed as an 8-well pad that targets two benches of the Granitic Basement formation.

ciencies. The success of the multistage stimulation and the unprecedented power density achieved through the multi-bench development strategy highlight the potential for these technologies to drastically improve the economics of geothermal energy while minimizing the environmental footprint of EGS technology.

The ability to achieve and maintain high production temperatures without thermal decline, as demonstrated in both projects, is a significant milestone for the geothermal industry. Furthermore, the success of the first multi-bench development indicates that future EGS projects could achieve even greater power outputs from smaller surface footprints. These advancements not only enhance the commercial viability of EGS but also position geothermal energy as a key player in the global transition to clean, reliable, and sustainable energy sources.

Overall, the findings from these projects suggest that the integration of oil and gas technologies into geothermal development could catalyze a new era for the industry, with the potential to unlock vast, untapped geothermal resources both in the United States and globally. Continued innovation and learning from ongoing and future projects will be crucial in refining these methods and expanding their application, ultimately contributing to a more sustainable and resilient energy future.

References

Augustine, C. 2016. “Update to enhanced geothermal system resource potential estimate.” Geothermal Resources Council.

Augustine, C., S. Fisher, J. Ho, I. Warren, and E. Witter. 2022. *Enhanced Geothermal Shot Analysis for the Geothermal Technologies Office.* Technical report NREL/TP-5700-84822. National Renewable Energy Laboratory.

DOE. 2019. *GeoVision: Harnessing the Heat Beneath our Feet.* Technical report. U.S. Department of Energy (DOE).

Fercho, S., G. Matson, and McConville E. 2024. “Geology, temperature, geophysics, stress orientations, and natural fracturing in the Milford Valley, UT.” 49th Workshop on Geothermal Reservoir Engineering, Stanford, California, USA.

Fercho, S., J. Norbeck, and McConville E. 2023. “Geology, state of stress, and heat in place for a horizontal well geothermal development project at Blue Mountain, Nevada.” 48th Workshop on Geothermal Reservoir Engineering, Stanford, California, USA.

Grant, M.A., and P.F. Bixley. 2011. *Geothermal Reservoir Engineering.* Academic Press.

Norbeck, J., T. Latimer, and C. Gradl. 2023. “A review of drilling, completions, and stimulation of a horizontal geothermal well system in north-central Nevada.” 48th Workshop on Geothermal Reservoir Engineering, Stanford, California, USA.

Ricks, W., K. Voller, J.H. Norbeck, J.D. Jenkins, F.J. de Sisternes, and R.K. Lester. 2014. “The role of flexible geothermal power in decarbonized electricity systems.” *Nature Energy,* https://doi.org/10.1038/s41560-023-01437-y.

Ricks, Wilson, Jack Norbeck, and Jesse Jenkins. 2022. “The value of in-reservoir energy storage for flexible dispatch of geothermal power.” *Applied Energy* 313:118807. ISSN: 0306-2619. https://doi.org/https://doi.org/10.1016/j.apenergy.2022.118807.

Ross, J.G. 2001. *Guidelines for the Evaluation of Petroleum Reserves and Resources.* Society of Petroleum Engineers.

El-Sadi, K., B. Gierke, E. Howard, and C. Gradl. 2024. “Review of drilling performance in a horizontal EGS development.” 49th Workshop on Geothermal Reservoir Engineering, Stanford, California, USA.

Sepulveda, N.A., J.D. Jenkins, F.J. de Sisternes, and R.K. Lester. 2018. “The Role of Firm Low-Carbon Electricity Resources in Deep Decarbonization of Power Generation” [in English (US)]. *Joule* 2 (11): 2403–2420. ISSN: 2542-4351. https://doi.org/10.1016/j.joule.2018.08.006.

Williams, C.F., M.J. Reed, R.H. Mariner, J. DeAngelo, and S.P.J. Galanis. 2008. *Assessment of moderate- and high-temperature geothermal resources in the United States.* Technical report. US Geological Survey, number=USGS Fact Sheet 2008-3082.