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Can Next-Generation Enhanced Geothermal Systems Succeed in Deep Sedimentary Basins?

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ABSTRACT

Deep sedimentary basins contain significant geothermal resources for power generation, and these regions often benefit from existing oil and gas infrastructure, subsurface data, an experienced workforce, permitting regulations, and growing power demand. Despite these advantages, field demonstrations and commercial development of the latest styles of Enhanced Geothermal Systems (EGS) have predominantly focused on crystalline basement reservoirs in the western US. In deep sedimentary basins, such as the US Gulf Coast, potential EGS target temperatures (for power generation) are typically located at depths of 4 to 6 kilometers due to modest temperature gradients. Compared to EGS in high-heat flow areas in the western US, these greater target depths result in higher drilling and completions costs, making geothermal power generation less competitive compared to existing natural gas and renewable energy markets. Yet, with novel cost-efficient development and production strategies, geothermal could be attractive for baseload power generation. This study discusses similarities and differences between crystalline basement and deep sedimentary rocks, such as tight sand and shale. What can be done to make EGS at scale in deep sedimentary basins more viable? The study reviews some of the practices of EGS and oil/gas industries and explores whether those are necessary and practically applicable to EGS development in deep sedimentary rocks or if innovative methods or hybrid approaches (e.g., new well configurations, stimulation operations, reactive fracture growth, fluid design, etc.) could enable cost-effective and sustained heat production. The study shows preliminary modeling results from deep sedimentary reservoirs in the US Gulf Coast, which could be good candidates for EGS field pilot tests. The findings, conceptual framework, and proposed recommendations in this study provide a road map for future research and practical implementation of EGS in deep sedimentary basins.

1. INTRODUCTION

Deep sedimentary basins in the US, such as the Gulf Coast, East Texas, Appalachian, and Williston basins, have significant geothermal resources that can potentially be used for direct use and power generation (Richards and Blackwell, 2012; Stutz et al., 2015; Gosnold et al, 2019; Bhattacharya et al., 2022; Wisian et al., 2023; Gelman and Burns, 2025). Often, these basins produce hydrocarbons, critical minerals, and have existing infrastructure and permitting frameworks that could be used for geothermal exploration and development. For the Gulf Coast of Texas, several wells with subsurface data exist from depths of >4 km, with temperatures exceeding 200°C. A few field tests have been completed in the sedimentary basins , such as Pleasant Bayou on the Texas Gulf Coast and the DEEP project in the Williston Basin, Canada (Bebout et al., 1979; Davis et al., 1981; Riney, 1991; Marcia et al., 2021). These projects applied conventional geothermal technologies and co-production strategies. Although these technologies have potential for generating power, there are challenges with regards to scalability and sustained flow rate and require reservoir permeability that is frequently not found at these target depths in sedimentary basins. We propose that deployment of Enhanced Geothermal Systems (EGS) along with other technologies could transform deep sedimentary basins into economically viable targets for commercial geothermal development. EGS in sedimentary basins opens new opportunities for geothermal baseload power generation in parts of the US that have not previously considered targets for geothermal energy.

EGS field demonstrations over the last 50 years have predominantly been in crystalline basement environments and not in deep sedimentary strata (Lipton and Seligman, 2025). EGS in crystalline rocks consistently faces major challenges with fluid loss, maintaining flow rate, and sustained thermal longevity. An evaluation of historical EGS stimulations also found that injections typically stimulate pre-existing fractures but also induce some new fractures away from the wellbore, leading to short-circuiting and induced seismicity.

In sedimentary basins, such as the regions within the US Gulf Coast Basin, the geothermal gradient is generally 30–40°C/km, reaching temperatures of 150–200 °C at depths of 4–6 km. This is significantly deeper than hydrothermal and EGS projects in the western US (with higher geothermal gradients). While partially compensated by lower drilling costs per foot in sedimentary rocks compared to crystalline rocks and by lower deployment costs in established oil and gas fields, greater target depths may result in overall higher drilling and completion costs for power generation, compared to crystalline reservoirs with higher heat flow. High well costs are a key barrier since drilling can constitute up to 50-75% of total geothermal project capital cost. In addition, hydraulic fracturing effectiveness is limited due to operational inefficiencies of surface frac fleets beyond a pressure limit of ~15,000 psi. Therefore, the questions that need to be asked are: whether EGS can be applied to deep sedimentary basins successfully, what are the benefits, what can be done to increase its scalability, and make it competitive with other energy sources?

We propose that EGS developed in deep sedimentary basins represent a compelling pathway for baseload power generation due to a combination of technical, operational, and economic advantages. These basins commonly contain extensive legacy oil and gas infrastructure, including deep wells, surface facilities, and grid interconnections, which can significantly reduce upfront capital expenditures and development risk. Hydrocarbon-producing sedimentary basins are typically characterized by dense subsurface data coverage, including 2D and 3D seismic, well logs, core, and pressure–temperature measurements, enabling more robust reservoir characterization and lower exploration uncertainty for geothermal resources. The presence of an experienced regional workforce and established drilling, completion, and supply-chain capabilities further enhances project development at scale.

From geologic and geophysical perspectives, sedimentary formations generally exhibit better-defined stratigraphic architecture, reservoir heterogeneities, and mechanical layering than crystalline basement rocks, allowing more reliable geophysical imaging, geomechanical modeling, and fracture design. These formations are typically easier to drill and complete, and they support zonal isolation and staged hydraulic stimulation, improving control over fracture initiation, propagation, and connectivity.

Beyond electricity generation, deep sedimentary basin EGS projects may enable co-production of hydrocarbons and critical minerals from brines, providing additional revenue streams and improving overall project economics. Taken together, the combination of improved subsurface characterization, enhanced controllability of stimulation, existing infrastructure, and resource co-production potential positions EGS in sedimentary basins as a more predictable and scalable alternative as well as complementary to crystalline basement–hosted EGS for commercial deployment to unleash energy dominance everywhere.

Moreover, many hydrocarbon-producing basins, such as the Gulf Coast, benefits from a dense, mature oil and gas supply chain, including drilling, stimulation, and manufacturing as well as relatively abundant water availability, which together lower costs and execution risk for EGS deployment. In contrast, EGS development in crystalline rocks in the western US often faces more limited service availability, higher mobilization and logistics costs, and increased water-supply constraints for stimulation, adding material development risk as these projects mature over time.

Our study reviews some of the modern practices of EGS in crystalline basement rocks and oil and gas (O&G) industries in tight sedimentary rocks and explores the fundamental differences between them in terms of rock characteristics and their roles on the efficacy of drilling and completions. We present reservoir simulations of heat production from the hot, tight Wilcox reservoir on the Gulf Coast using modern EGS approaches (multi-stage stimulation of horizontal wells and proppant use) in crystalline basement rocks as the base case and comparing its performance with recent completion styles in typical unconventional O&G wells in the Gulf Coast and huff-n-puff approaches. We have excluded porous and permeable hot sedimentary aquifers from this study to focus on EGS potential in hot tight sedimentary rocks at depth, which are abundant and scalable for power generation.

2. CHALLENGES OF EGS IN CRYSTALLINE ROCKS VS. DEEP SEDIMENTARY BASINS

The concept of EGS emerged in the 1970s with experiments in Fenton Hill in New Mexico and has been tested in various settings worldwide since then. EGS in granitic and deep sedimentary basins share the same goal of creating an artificial permeability that is capable of heat and fluid transfer from the reservoir. However, the two differ markedly in their geologic properties, their controls on fracture initiation and growth, and in the techniques by which engineers can effectively stimulate and sustain the reservoir. Recognizing these differences is crucial to formulating successful strategies for EGS in sedimentary basins. Note that there are more ways these rocks are different from each other, including typically better geophysical imaging quality of sedimentary reservoirs than crystalline basement, leading to better targeting.

Temperature and depth: While EGS projects in crystalline rocks have targeted regions with high-temperature gradients near active magmatic or tectonic regions, deep sedimentary basins have modest geothermal gradients. Geothermal gradients in many parts of the US Gulf Coast are on the order of 30-40 °C/km, which may require a depth of 4-6 km to reach 150-200 °C in many areas. This means low energy density per well. One way to compensate for this is by accessing large reservoir volumes, which requires stimulation to achieve extensive connectivity. In addition, compared to crystalline reservoirs, sedimentary reservoirs at the same target temperature tend to have measurable matrix permeability and porosity that can aid in circulation. Deep sedimentary formations, such as Wilcox, underwent significant reduction in primary porosity due to diagenetic reactions at high temperatures filling primary porosity, and, in some cases, creating secondary porosity (Loucks and Dutton, 2019). Porosity and permeability in these reservoirs decrease significantly with increasing temperature, making them targets for EGS.

Reservoir pressure: Reservoir pressure in deep sedimentary formations can be above hydrostatic or abnormal (pressure gradient >0.5 psi/ft), whereas pore pressure gradients in crystalline rocks tend to be nominally hydrostatic. Abnormal pore pressure adversely impacts drilling and completion of geothermal wells in sedimentary basins. Abnormal pore pressure requires added precautionary measures for wellbore stability and increases costs associated with fluid injection during production. On the other hand, increased pore pressure assists with maintaining hydraulic conductivity of natural and induced fractures and thus enhances geothermal heat extraction. In contrast, crystalline reservoirs are mostly in a hydrostatic condition that limits the opening of fractures.

High pressure-high temperature (HPHT) conditions over the lifecycle of the well increase the casing corrosion rates and material degradation. High temperatures cause thermal expansion, which can induce compressive or tensile stress. The casing design must account for thermal cycling and ensure sufficient wall thickness and material strength to prevent buckling or yielding (Torrealba et al., 2025).

Well drilling and completion: Drilling operations of a geothermal well are quite similar and at the same time different from drilling an O&G well. Due to their stiffness, intact granitic rocks slow the rate of penetration and cause more bit wear, increasing the cost, compared to sedimentary rocks. There are fewer issues in drilling sedimentary formations than those that plague deep granite drilling (Davalos-Elizondo et al., 2023).

The use of polycrystalline diamond compact (PDC) bits is the standard in drilling many unconventional shale reservoirs, whereas it has been recently introduced to geothermal well drilling in hard crystalline rocks. This resulted in a dramatic decline in the number of days for drilling, thereby reducing the cost (Samuel et al., 2022). The continued development of PDC bits, thermally stable PDC bits, and hybrid drill bits combining PDC with roller-cone technology is essential for enhancing the durability and performance of drill bits in high-temperature and abrasive conditions typical of geothermal wells (Isania et al., 2024).

The targeted formations are either completed with an open-hole or slotted/perforated liner hung or set on the bottom. In contrast, the producing zone in O&G wells is usually confined to a small, well-defined, vertical interval, and tubing is cemented in place and perforated (Hickinson, 2020). In many geothermal wells, casing is cemented with a complete cement sheath from bottom to surface, unlike many O&G wells, where cementing may be limited to the lower casing interval. This cement has two important functions: to give the casing mechanical support under its sometimes-intense thermal cycling between production and shut-in, and to protect the outside of the casing from corrosion by in-situ fluids (Finger et al., 2010).

Effective well completions at depth can make or break an EGS project. The absence of mechanical stratigraphy in igneous formations favors vertical height growth of hydraulic fractures, with potential non-unform proppant placement, compared to layered sedimentary rocks, where mechanical layer contrast results in more confinement within zone. Regardless of lithology, completion of deep geothermal targets can pose challenges to industry-standard hydraulic fracturing operations due to the operational pressure limits of frac fleet (~15,000 psi).

Flow rates and well spacing: Geothermal power production needs a significantly high flow rate through the reservoir to extract sufficient heat. A general rule of thumb is that an EGS doublet needs 50-100 kg/s (~32,000-65,000 barrels/day) of circulating fluid to generate tens of megawatts of thermal power. In sedimentary well-doublet geothermal systems, the extractable power is fundamentally controlled by the mass flow rate and the produced-to-injected temperature difference (Mahbaz et al., 2021). Many historical EGS projects in crystalline rocks have had difficulty attaining those rates and end up suffering fluid losses or pressure drops.

A sedimentary basin case study from the Wattenberg Field (DJ Basin, Colorado) illustrates how both circulation rate and well spacing directly control geothermal performance. In their optimized development scenario, the authors report an injector–producer spacing of approximately 1,000 m with a circulation/injection rate of around 60 kg/s, which produced a sustained thermal power output on the order of tens of megawatts over the modeled period (Akindipe et al., 2024).

Induced seismicity: EGS in crystalline and sedimentary reservoirs can induce seismic events, but the risk profile may differ. Induced seismic events are more likely in reservoirs of low permeability where dissipation of induced excess pore pressure occurs at a lower rate thus leading to higher pore pressure anomalies compared to drained conditions in highly permeable rocks. On the other hand, thermo-poroelastic effects are more pronounced in rocks of higher porosity because thermal expansion coefficients of the liquid phase are higher than of the solid phase. The competing effects need to be evaluated as a function of fracture and matrix permeability and thermo-poroelastic properties of the matrix and the pore fluid, and the thermodynamic properties of the fluid phase. EGS stimulation in weak volcanic or sedimentary formations (e.g., Berlin, El Salvador, Groß Schönebeck) may lead to permeability enhancement that differs fundamentally from that in crystalline rock systems (e.g., Basel, Cooper Basin, Soultz-sous-Forêts). Whereas hydro-shearing often dominates stimulation in hard crystalline rocks, stimulation in sedimentary formations may involve a greater contribution from tensile fracturing (mode I) (Zang et al., 2014). Well-cemented sedimentary rocks in deep wells may approach the behavior of crystalline rocks depending on the strength contrast between intact rock and existing fractures and faults.

Several EGS projects have been terminated due to induced events (e.g., Basel, Strasbourg, Pohang). In contrast, others (e.g., Soultz-sous-Forêts, Helsinki, Blue Mountain, Utah FORGE) demonstrate that seismic risk can be managed through state-of-the-art monitoring and operational control (Zhou et al., 2024). Unlike large-volume wastewater injection in unconventional O&G reservoirs that creates regional to basin-wide pressure anomalies, pressure anomalies in geothermal production are spatially restricted that are easier to monitor and mitigate.

3. ADAPTING OIL AND GAS TECHNOLOGY TO EGS RESERVOIRS IN SEDIMENTARY BASINS

The extraction of oil and gas from unconventional reservoirs has led to the development of an array of technologies that could be game changers if applied to geothermal. Tight shale and sandstone development has demonstrated effective methods for producing from low-permeability rocks, and therefore, similar techniques can be adapted for producing heat at scale.

Advanced well configurations: A fundamental shift has been moving from traditional vertical to horizontal multilateral well designs in geothermal reservoirs. In O&G reservoirs, horizontal wells have been proven to be invaluable to maximize reservoir contact since these wells extend laterally. Geothermal projects historically have used mostly vertical wells; however, the trend has been changing recently (e.g., Utah FORGE, Project Cape, and Project Red). A horizontal production well could intersect a larger number of fractures, improve sweep and reduce thermal drawdown. Modeling studies indicate that multilateral well systems can significantly improve heat extraction efficiency by distributing flow and accessing more of the reservoir.

Deviated (U-shaped, V-shaped, inclined V-shaped, and pipe-in-pipe configurations) and multi-segment geometries can meaningfully change thermal performance and the rate of production-temperature decline. Advanced EGS configurations, demonstrate exceptional heat extraction capacities suitable for electricity generation in the deeper and more complex reservoirs (Nassereddine et al., 2024).

Zhai et al. (2025) simulated a multilateral horizontal EGS in a hot granite and found it delivered 2.9 MW with a slower temperature decline than a vertical well doublet, with only 8% temperature drop over 20 years. The multilateral setup outperformed the conventional doublet by yielding higher production temperature and power output. Well configurations also strongly influence the geometry of the stimulated volume and the practicality of drilling wells that reliably intersect the created fracture network; for example, with vertically oriented fractures, a horizontal well arrangement creates a larger drilling window for fracture intersection compared to vertical wells (Polsky et al., 2008).

Multi-Stage stimulation and proppant use: The application of multi-stage hydraulic fracturing represents one of the most critical technology transfers to EGS. The multi-stage method divides the wells into segments that stimulate each stage independently. Experience in shale reservoirs has shown that dozens of stages can be created in a single well to create an extensive fracture network.

The geothermal industry has historically emphasized single-stage, open-hole shear stimulation, where water injection induces slip on natural fractures and faults and relies on self-propping mechanisms. However, the oil and gas industry has achieved major performance improvements through the combined use of multi-stage stimulation and proppant placement, yet these technologies have not been widely adopted in EGS due to concerns about high-temperature zonal isolation reliability and the preference for open-hole completions (Porlles et al., 2023). Multi-stage hydraulic fracturing enabled through zonal isolation is a key approach for constructing engineered fracture networks in geothermal reservoirs. These approaches are being used in recent EGS wells.

If the natural fracture system is poorly developed within the reservoir, conventional hydraulic fracturing with a high injection rate needs to be performed to create open tensile fractures. In contrast, if the natural fracture networks are relatively well developed before the hydraulic stimulation, low-rate cyclic injections may be preferred to drive the shear slip of natural fractures for increasing reservoir permeability. Thus, a sufficiently comprehensive understanding of natural fracture distribution within the target reservoir near the injection well is needed for a successful hydraulic stimulation design and optimization (Jia et al., 2022).

Reactive stimulation and fracture growth: In sedimentary rocks, not only hydraulic fracturing but chemical reactions can contribute to permeability enhancement. In carbonates or siliciclastic reservoirs with carbonate cement, stimulation with acidic water can enlarge pre-existing fractures and/or dissolve pore throats. The O&G industry routinely performs acid stimulation to increase production. This concept can be extended to geothermal reservoir stimulation. After initial fracturing, an acid or other reactive fluid can be injected to enhance fracture conductivity by dissolving asperities and creating flow channels. For example, at the Cooper Basin EGS project in Australia (Habanero), an acid flush was used post-frac to dissolve carbonate minerals filling natural fractures and significantly improved well injectivity (Lucas et al., 2020). In addition, recent research also introduced the use of chelating agents at high temperatures to selectively dissolve certain minerals in granites. In lab tests at 200 °C under stress, this approach increased permeability by up to six-fold in just 2 hours of treatment (Watanabe et al., 2021). The chelating solution created stable voids in the fracture by preferentially leaching biotite, without the rapid spending and corrosion issues of strong mineral acids. Hybrid stimulation strategies should be employed for sedimentary basin EGS: using hydraulic fracturing to create connectivity and then chemical fluids to enlarge and sustain the flow paths. New developments like retarded acids and self-diverting acids could find application. Case studies from O&G wells have shown that retarded acids can penetrate tens of meters into hot carbonates, creating long conductive channels.

Besides the dissolution of soluble mineral phases, laboratory measurements of fracture mechanical properties under a range of fluid-chemical conditions have demonstrated that fracture growth processes can be controlled as a function of salinity and pH and the rate and magnitude of the pore pressure increase, leading to critical or sub-critical fracture growth with differing fracture geometries (Callahan et al., 2020; Chen et al., 2020). These effects can potentially be employed to engineer a stimulated fracture geometry that optimizes fracture connectivity and fracture size distribution, and thus the stimulation outcome.

4. NUMERICAL RESERVOIR SIMULATION CASE STUDY

A three-dimensional box model of the deep Wilcox reservoir on the Gulf Coast was constructed. The numerical simulation study is intended to demonstrate a long-term thermal drawdown behavior in a hydraulically fractured horizontal well doublet system in a deep sedimentary reservoir setting. A detailed study into the geological and petrophysical properties has been undertaken in Mawa et al. (2025), upon which this model is based (Table 1). The modeled reservoir is located at a depth of 5,000 m, with an initial reservoir pressure of 80,000 kPa and a uniform initial temperature of 200 °C. These values are consistent with deep Gulf Coast sedimentary formations that are typically overpressured. Porosity and permeability of the Wilcox decrease sigificantly with increasing temperature and depth. Based on Wilcox core data from multiple wells at depth, average porosity in the model is assigned as 0.1, and permeability as 1 mD (Loucks and Dutton, 2019; Bhattacharya et al., 2022). Most of the porosities left in the Wilcox at a temperature above 150 °C are secondary porosity formed due to diagenesis. Deep Wilcox is mostly composed of shale, siltstone, and very fine-grained sandstone. It contains very few natural fractures. Figure 1 shows the aerial view of the reservoir model used in this study.

Embedded Discrete Fracture Model (EDFM) is used to represent two hydraulically fractured horizontal wells (Sepehrnoori et al., 2020). The basic idea of EDFM involved generating the matrix grid without considering the locations of fractures, and discretizing the fractures using matrix gridblock boundaries. This separates the fractures from the matrix and uses non-neighboring connectors to represent the flow between the matrix and the fracture domains. In EDFM, when a fracture intersects a matrix cell, an additional computational cell is introduced to represent the corresponding fracture segment in the physical domain. As a result, each fracture may be discretized into multiple fracture segments based on the boundaries of the surrounding matrix gridblocks. To distinguish these newly introduced cells from the original matrix cells, they are referred to as fracture cells. For each fracture, only one fracture cell is created within each matrix gridblock it penetrates, and each fracture segment is associated with a single matrix cell. This relationship simplifies the evaluation of transmissibility and the establishment of flow connections between the fracture and matrix domains.

Completion parameters were selected to represent two end-member designs: modern EGS in crystalline basement rocks with short horizontal wells, fewer stages, and larger fracture height to maximize vertical heat access and stimulated rock volume, and an unconventional shale-style configuration with longer laterals and higher stage density to distribute flow laterally. For the modern EGS style simulation as applied to crystalline basement rocks, we used publicly available completions data from Fervo Energy's Project Cape and Project Red as the base case (Norbeck and Latimer, 2023; McConville, 2023; Titov et al., 2024; Singh et al. 2025). Since not all information was publicly available from one single site, we had to combine data from two projects. This serves as a representative of state-of-the-art EGS style completion. The base case for completions serves purpose to observe the outcome of transferring lessons from a crystalline reservoir to a deep sedimentary reservoir. Each horizontal well (injector and producer) for this case is completed with 16 stages, with a stage spacing of 45 m. A height of 228 m is used here to represent a vertically extensive stimulation typical of EGS designs in a hard rock setting. Within each stage, 6 clusters are represented. The properties for the hydraulically fractured wells are shown in Table 2. The simulation was run using CMG-STARS (CMG, 2025) for a period of 30 years. In addition to this, because only 24-hour production data from Cape Station is publicly available, we used 5,000 m^3/day, which is in the ballpark of the 37-day flow test in Project Red (Norbeck and Latimer, 2023).

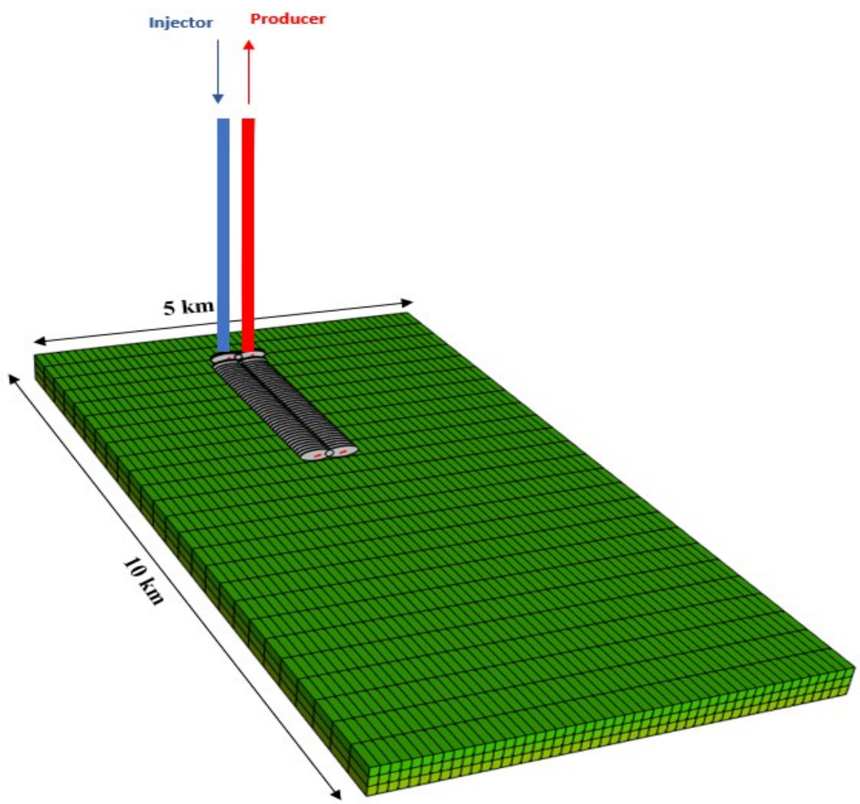

Figure 1: Three-dimensional view of the sector of the reservoir simulation model along with the wells (injector well in blue and producer well in red) and hydraulic fractures. Matrix grids are shown in green; fracture grids (ellipses) are in gray.

In our study, the total energy rate (J/day) by a well is calculated as:

$$E_w(t) = \sum_{\alpha} m_{\alpha}(t) h_{\alpha}(t)$$

Thermal power in MWth is calculated as:

$$P(t) = \frac{\sum_p E_p(t) - \sum_i E_i(t)}{86400\ X\ 10^6}$$

where:

$E_w(t)$ = total energy production rate of well w at time t (J/day)

$m_{\alpha}(t)$= mass flow rate of phase or component α in the well stream at time t (kg/s)

$h_{\alpha}(t)$= specific enthalpy of phase or component α at time t (J/kg)

α = fluid phase or component contributing to the well stream (e.g., water, steam)

$P(t)$= net thermal power extracted from the reservoir at time t (MW)

$E_p(t)$= energy production rate of producer well p (J/day)

$E_i(t)$ = energy injection rate of injector well i (J/day)

Table 1: Input properties for the numerical simulation of the deep Wilcox reservoir on the Gulf Coast of Texas

Properties	**Values**
Model Dimensions	10 km x 5 km x 0.5 km
Number of Grid Blocks	30 x 50 x 20
Depth	5,000 m
Porosity	0.1
Permeability	1 mD
Pressure	80,000 kPa
Temperature	200 °C
Producer Constraints	
Minimum Well-Head Pressure	5,000 kPa
Maximum Production Rate	5,000 m^3/day
Injector Constraints	
Maximum Bottom-Hole Pressure	90,000 kPa
Maximum Injection Rate	5,000 m^3/day

Table 2: Well completions properties for the input models. EGS completion paramters in crystalline basement are based on Project Cape and Red (Norbeck and Latimer, 2023; McConville, 2023; Titov et al., 2024; Singh et al., 2025); unconventional O&G completion parameters are from recently completed wells in the Gulf Coast, including Eagle Ford and Haynesville shale wells (Wood Mackenzie, 2026)

Properties	**Recent EGS completion style in crystalline basement (baseline)**	**Recent completion style in unconventional O&G (average values)**
Length of Lateral	1,600 m	2,530 m
Fracture Conductivity	121.92 mD.m (Project Red)	76.2 mD.m
Half Length	200 m	200 m
Fracture Height	228 m (Project Cape)	30 m
Number of Hydraulic Fracture Stages	16 (Project Red)	48
Stage Spacing	45 m (Project Cape)	45 m
Number of Clusters per Stage	6 (Project Red)	6

Figure 2 shows the total energy produced for the base case scenario in the deep sediemntary reservoir. The base case for dynamic simulation in Wilcox uses latest EGS completions styles as applied to crystalline basement rocks. The overall trends indicate that the system initially produced high-temperature water. As circulation continues, cooling near the fractures occurs, and the temperatures decline depending on the evolving thermal front. The produced thermal energy declines steadily from about 31 MWh to approximately 10 MWh over 30 years, primarily driven by the reduction in production temperature under constant flow rate constraints. The worldwide review of published data from geothermal power plants gives an average conversion efficiency of 12% (Zarrouk and Moon, 2014). Therefore, based on this, the electricity produced ranges from 3.72 MWe to 1.2 MWe. We understand that with improved technologies, the conversion effciency can go up.

Spatial distribution of thermal drawdown at the end of 1 year, 15 years, and 30 years is shown in Figure 3. Figure 3 shows progressive cooling around the stimulated region, thereby highlighting that the effective thermal sweep efficiency is controlled by engineered fracture geometry. Note that the deep Wilcox in the study has minimal natural frcatures. Over time, a cooling front propagates through the fracture network toward the producer, progressively reducing temperatures along the main flow pathways. By 30 years, significant cooling is observed in the interwell region, while outer portions of the stimulated volume remain comparatively hot, indicating sustained conductive heat recharge from surrounding rock.

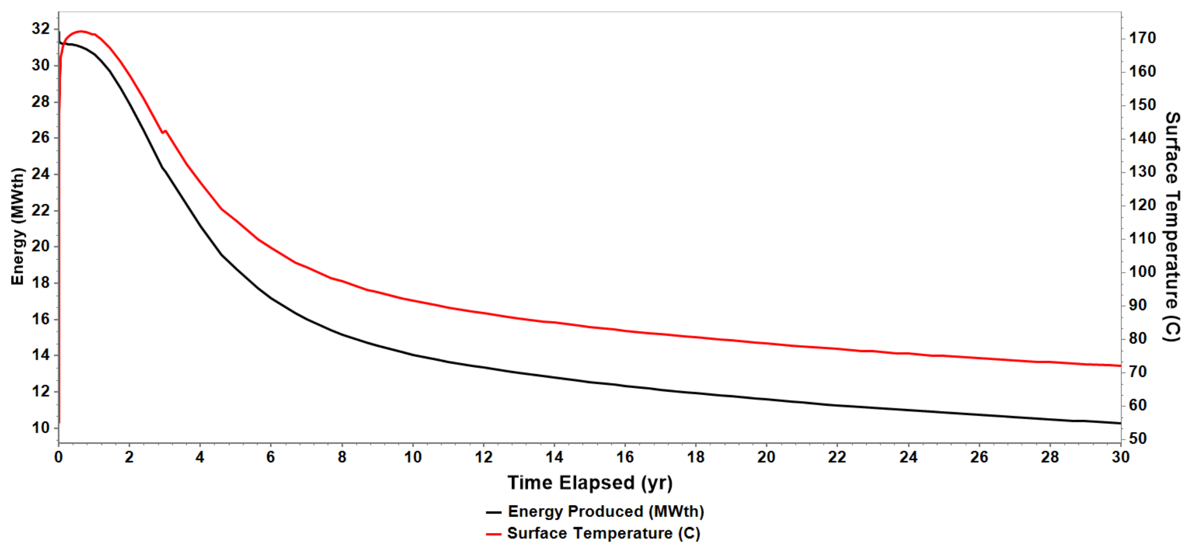

Figure 2: Total energy produced in MW thermal and surface temperatures in °C obtained in the base case (e.g., latest EGS style in crystalline rocks).

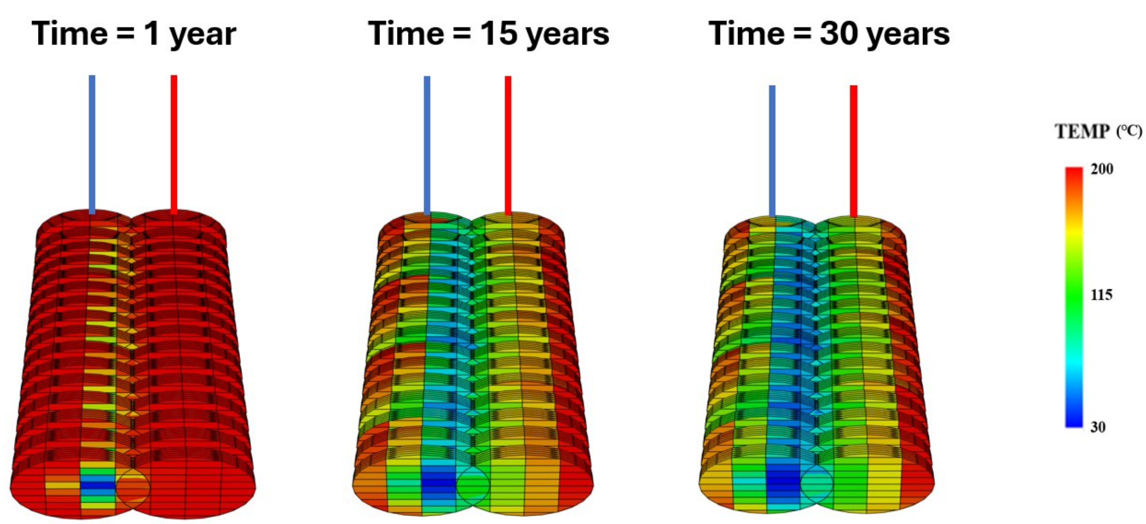

Figure 3: Temperature distribution in the EDFM grid blocks at the end of 1 year, 15 years, and 30 years in the geothermal style model. The blue and red vertical lines denote the injection and production wells, respectively. Colors represent reservoir temperature (°C), illustrating progressive thermal drawdown and heat sweep between the wells over time.

Developments in unconventional shale reservoirs have demonstrated that dense multi-stage hydraulic fracturing of long horizontal wells can significantly enhance reservoir connectivity and production performance. Motivated by these advances, the most recent Eagle Ford and Haynesville shale style completion parameters were used as the reservoir model in this study. The data was compiled from Wood Mackenzie database (2026). Keeping all reservoir properties and operating conditions unchanged, the lateral length, number of hydraulic fracture stages, and fracture height were modified to 2,530 m, 48 stages, and 30 m, respectively, to resemble typical completions unconventional O&G in the Gulf Coast. Tight sedimentary rocks (e.g., Eagle Ford) on the Gulf Coast have shown limited vertical height of hydraulic fractures, compared to other formations, thereby reducing the chance of creating tall and skinny fractures, potentially contributing to short-circuiting and non-uniform proppant placement. Our approach enables direct comparison between EGS in a crystalline reservoir and O&G-style multi-stage completion strategies and allows assessment of their relative effectiveness for heat extraction in deep sedimentary reservoirs.

Figure 4 compares the thermal energy production and produced surface temperature for the geothermal-style base case and the shale-style multi-stage completion design. Thermal energy produced in unconventional decreases from 32 MWth to 18 MWth or 3.72 MWe to 2.16 MWe using a conversion efficiency of 12%. While both cases exhibit similar early-time performance due to identical flow rate constraints and initial reservoir conditions, the unconventional O&G-style completion shows slightly lower initial produced temperatures followed by a slower long-term decline over the simulation period. Thermal energy output decreases in both cases, with the geothermal-style design exhibiting a sharper long-term decline driven by sustained high early heat extraction from a larger stimulated rock volume, while the unconventional O&G-style case maintains moderately higher energy output at later times due to distributed lateral flow along the extended horizontal well and increased number of fracture stages. Because fracture half-lengths were held constant, the observed differences are primarily attributed to variations in lateral length, fracture stage density, and fracture height between the two designs. Short-circuiting is not observed in this study because the fracture network is engineered and uniformly distributed, and the model does not include natural fracture systems or fault-controlled preferential flow paths. In addition, the formation is known to have few natural fractures from core studies.

Spatial evolution of temperature of the fractured horizontal well system for the unconventional O&G-style EDFM completion design at 1, 15, and 30 years of continuous circulation is shown in Figure 5. The results show a broad and laterally distributed thermal depletion zone that expands gradually with time, indicating efficient reservoir sweep and delayed localized thermal breakthrough. Cooling is not confined to a small number of dominant fracture pathways but instead occurs across multiple fracture stages along the lateral well, reflecting improved flow distribution associated with dense multi-stage stimulation. This distributed thermal front explains the sustained produced temperatures and higher long-term thermal energy output observed in the shale-style completion case relative to the EGS design in crystalline rocks.

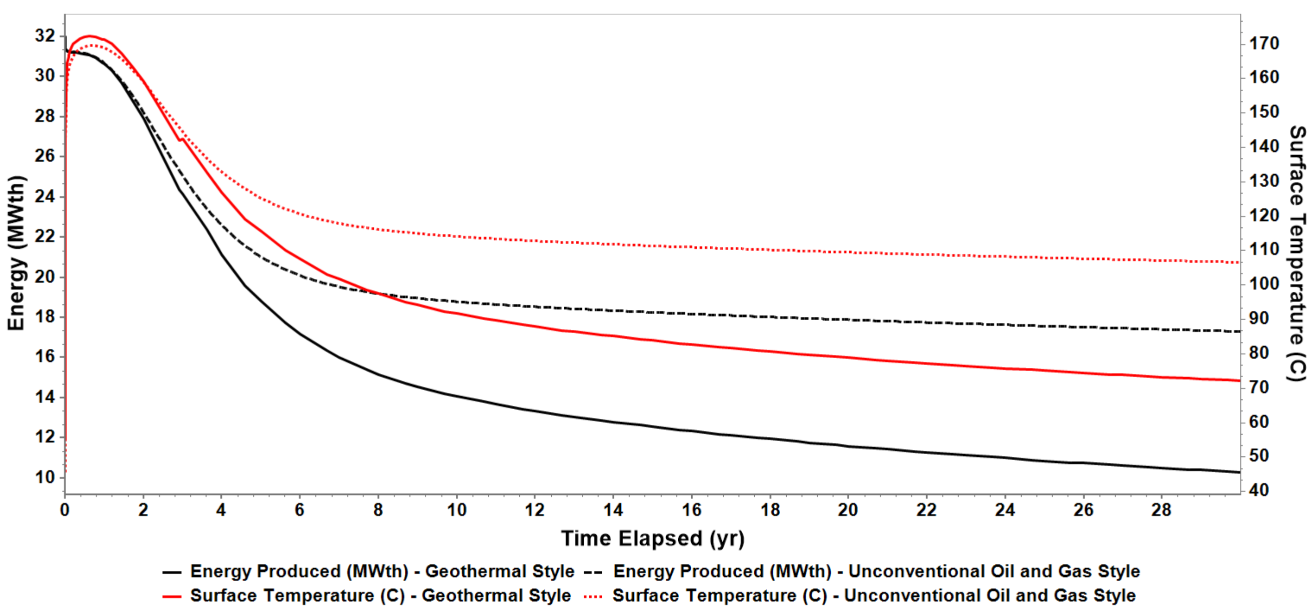

Figure 4: Comparison of total energy produced in MW thermal and surface temperatures in °C obtained from recent EGS style as applied to crystalline rocks (base case) vs. recent unconventional O&G completion style. Both systems exhibit an initial high energy output followed by progressive decline as the reservoir undergoes thermal depletion. The unconventional O&G–style design maintains higher surface temperatures and energy production over time, compared to the base case.

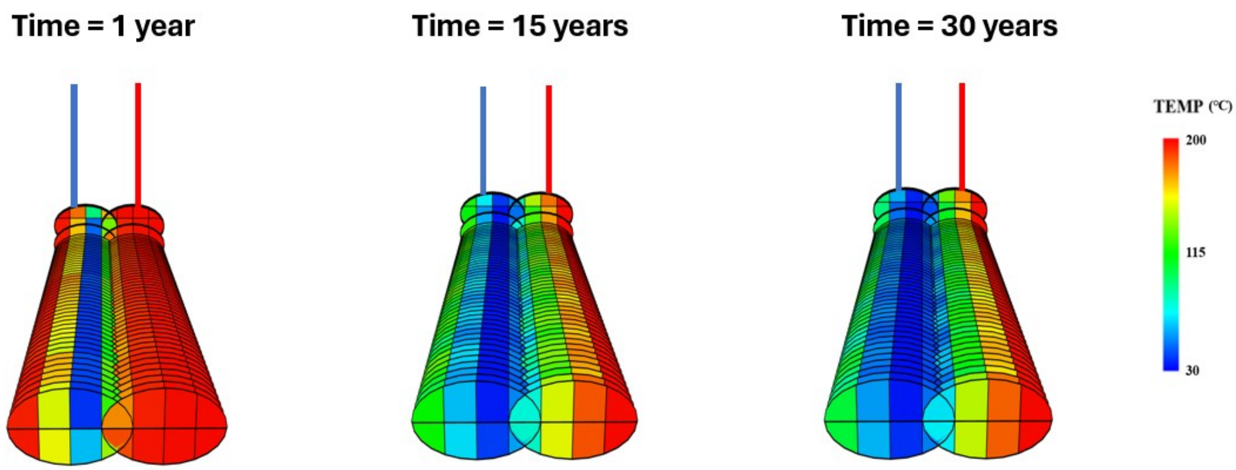

Figure 5: Temperature profiles within the EDFM fracture blocks for the unconventional oil and gas style case at the end of 1 year, 15 years, and 30 years. The injection (blue) and production (red) wells are shown vertically. Temperature contours (°C) demonstrate heat extraction along the fractured pathways and progressive thermal sweep across the reservoir.

In addition to continuous operations, the unconventional O&G style completion case was divided further into a huff-and-puff study, and we studied the impact over a period of 5 years. Each cycle lasts for one year with different injections, production, and residence times. The huff-and-puff technique, originally developed for cyclic single-well operations in low-permeability sedimentary reservoirs, has shown promise for improving oil recovery (Sekar et al., 2024). This is used as an operational strategy to reduce immediate thermal breakthrough, allow conductive thermal recharge of cooled regions and improve produced temperature during production windows. Table 3 highlights the simulation cases.

Table 3: A summary of simulated operational strategies for Unconventional O&G style development of EGS

Cases	**Injection Cycles**	**Soaking (well shut in)**	**Production Cycles**
Recent Unconventional Oil and Gas Completion Style Case	Continuous Injection and Production		
HnP: 3-6-3	3 months	6 months	3 months
HnP: 4-4-4	4 months	4 months	4 months
HnP: 5-2-5	5 months	2 months	5 months

In the cyclic huff-and-puff (HnP) cases, the produced surface temperatures are shown in Figure 6. During the soaking periods, fluid circulation is stopped, allowing temperature gradients between the cooled fracture surfaces and the surrounding hot rock to drive conductive heat transfer into the fracture network. As a result, when production resumes, the produced temperatures rebound relative to the continuously circulated unconventional-style case. Although the produced temperatures in all HnP cases are consistently higher than those observed under continuous circulation, there is not a huge difference among the three cyclic configurations considered (HnP: 3-6-3, 4-4-4, and 5-2-5). The difference in produced temperatures, however, keeps on increasing with more cycles and with more soaking leading to higher produced temperatures.

Correspondingly, the cyclic HnP operations generate comparatively greater thermal energy output, as shown in Figure 7. Among the cyclic cases, the HnP: 3-6-3 configuration yields the highest energy production. While soaking enhances the produced temperature by allowing partial thermal recovery of the fracture surfaces, it also reduces the total active production time within each cycle. Consequently, cumulative energy production will reflect a balance between increased thermal output during production windows and the reduced flow duration associated with shut-in periods.

Figure 8 further illustrates the temperature distribution within the fracture network for the different cyclic configurations. Cases with longer soaking periods retain higher fracture temperatures near the production stages due to enhanced conductive heat transfer from the surrounding rock, resulting in elevated produced temperatures upon flow restart. In contrast, cases with shorter soaking durations exhibit broader and colder corridors, reflecting more extensive thermal depletion along the main flow pathways and less time for conductive recovery. These spatial temperature patterns explain the observed differences in produced temperature rebound among the HnP cases and highlight the importance of conductive heat recharge in controlling cyclic geothermal performance.

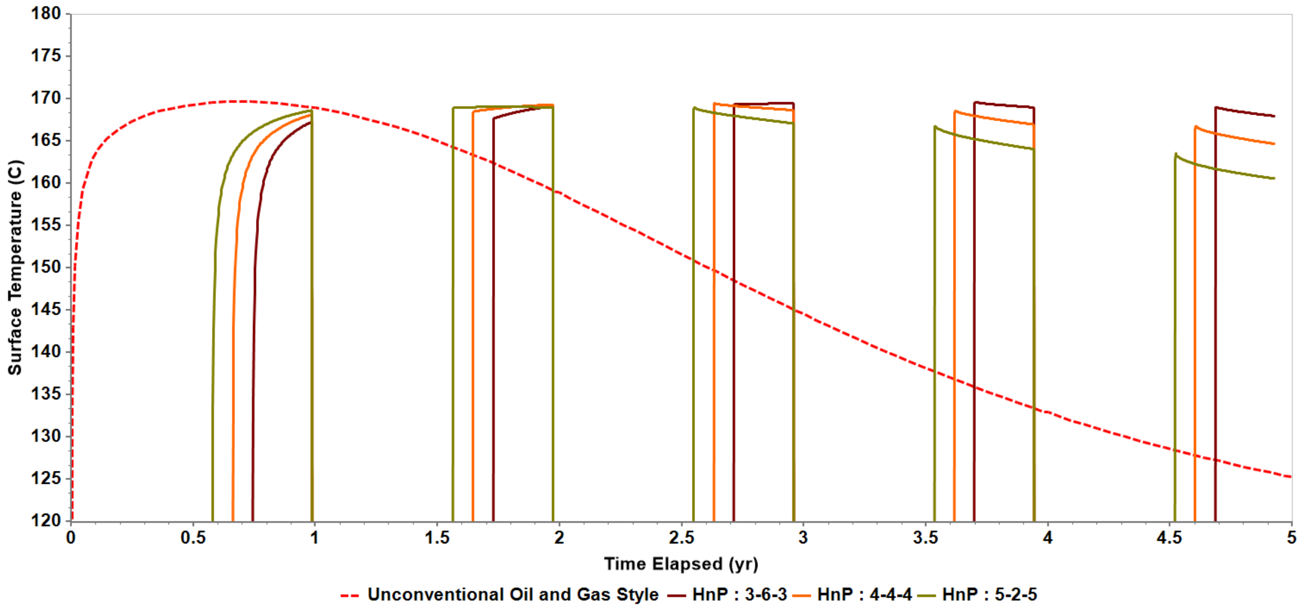

Figure 6: Surface temperature in °C during production for the different cyclic injection/production cases. The dashed red curve represents continuous production. The HnP cases exhibit periodic temperature peaks during each production phase. Longer soaking times maintain higher temperature recovery between cycles, whereas shorter soaking periods lead to faster temperature decline.

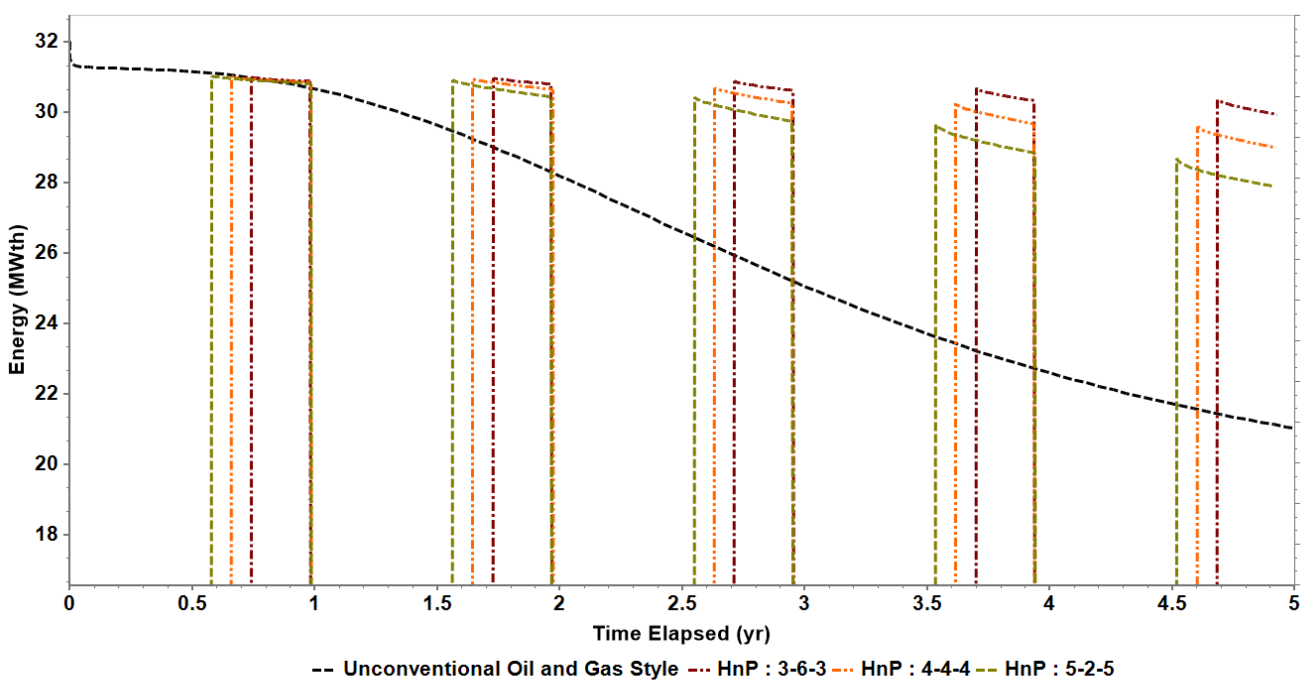

Figure 7: Thermal energy for all cases with different injections, soaking, and production schemes (in MWth). The dashed black curve represents continuous circulation, and the HnP cases display periodic spikes in energy corresponding to production phases following injection and soaking cycles. Among the HnP strategies, longer soaking times sustain higher energy recovery per cycle.

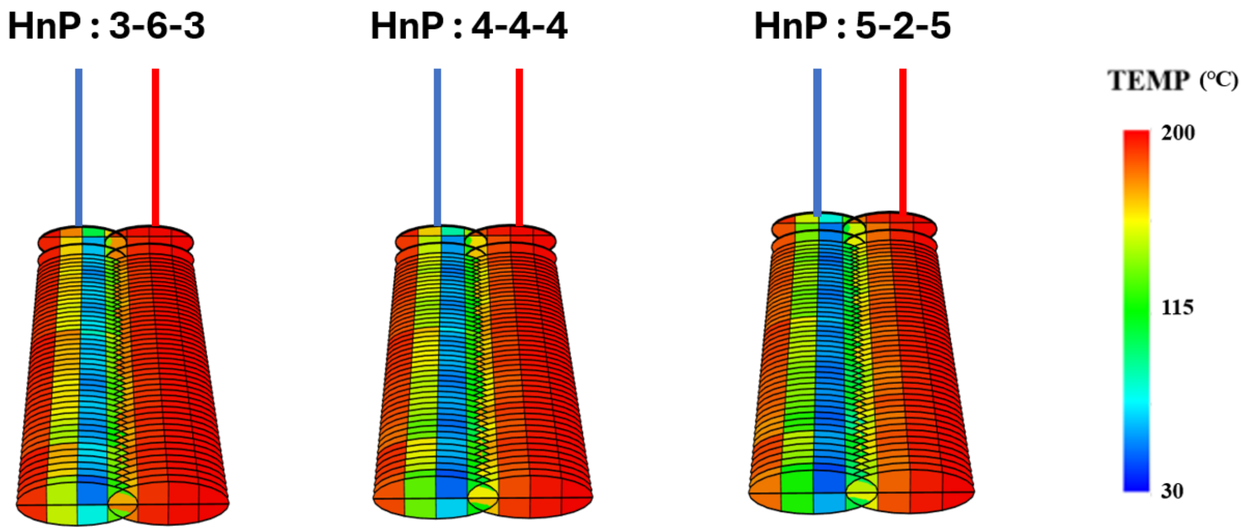

Figure 8: Temperature distribution within EDFM fracture blocks at the end of 5 years for different Huff-N-Puff: injection-soaking-production schemes HnP: 3-6-3, HnP: 4-4-4, and HnP: 5-2-5, respectively. The colors illustrate thermal depletion along the fractured pathways, with longer soaking periods maintaining higher temperatures near the injection region, while shorter soaking times result in greater cooling within the fracture grids. The blue and red vertical lines denote the injection and production wells, respectively

5. CONCLUSIONS

Deep sedimentary basins represent an important and underutilized geothermal asset (regardless of technologies) for power generation, providing strategic advantages like detailed subsurface information, existing oil and gas infrastructure, and a well-established regulatory framework. However, implementations of next-generation EGS have mainly concentrated on crystalline reservoirs, while deep sedimentary targets remain untested. This study evaluated the key technical differences between crystalline basement and sedimentary basin EGS, explored possibilities for technology transfer from unconventional O&G industry, and evaluated long-term thermal performance through a reservoir simulation case study, representative of the Wilcox geopressured reservoir in the US Gulf Coast. In our study, the unconventional O&G style completion design demonstrated a slower decline in produced temperatures and greater energy produced compared to EGS style applied to crystalline basement rocks.

Horizontal wells, multi-stage stimulation, proppant placement, and designed hydraulic fracture networks are especially important for deep sedimentary basin geothermal environments. Moreover, hybrid stimulation techniques might be particularly useful in sedimentary formations where mineral composition and geochemical reactivity can be utilized to maintain fracture conductivity and connectivity. Simulation outcomes show that EGS in deep sedimentary formations can maintain heat extraction for several decades and is regulated by thermal sweep influenced by hydraulic fractures.

Cyclic operating methods (huff-n-puff) can also enhance generated temperatures and thermal output in deep sedimentary formations even above continuous flow systems. We recommend further studies on the feasibility of EGS in deep sedimentary basins, including multiple small-scale field tests across the US.

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