Interreg
CENTRAL EUROPE

Co-funded by
the European Union

TRANSGEO

Proof-of-concept study on reuse of abandoned wells for Enhanced Geothermal System (EGS) Development

Version 1
04 2026

D1.1.4 Proof- of- concept study on reuse of abandoned wells for Enhanced Geothermal System (EGS) development

Author		
Lingkan Finna Christi christi@gfz.de	GFZ Helmholtz Center for Geoscience	Germany

Executive summary

Enhanced Geothermal System (EGS) technology unlocks high-power geothermal energy potential, even in challenging rock formations, by focusing on well intervention and reservoir stimulation. The process begins with assessing well integrity and may involve modifications like side-tracking or deepening, followed by hydraulic testing to evaluate reservoir performance. Crucially, the approach offers three pathways to success: revitalizing existing underperforming wells with simple stimulation treatments (potentially increasing productivity by 2-3x), developing large-scale Enhanced Geothermal Systems (EGS) through extensive stimulation of long horizontal well sections, and repurposing wells for more accurate monitoring of the stimulated reservoir volume. While technically proven, wider deployment hinges on successfully implementing these operations to achieve economic flow rates and expand geothermal energy access beyond traditionally permeable reservoirs.

The TRANSGEO project (https://www.interreg-central.eu/projects/transgeo/) is co-funded by the European Regional Development Fund through the Interreg Central Europe program. The overall objective of TRANSGEO is to investigate the potential to transform abandoned hydrocarbon wells into new sources of green geothermal energy. To reach this goal, the TRANSGEO team is providing new tools and knowledge to support communities and industries in the energy transition and to break down economic and technical barriers to well reuse.

A. Description of technology

Enhanced Geothermal Systems (EGS) are defined as artificial or engineered reservoirs created to extract heat from low-permeability geothermal resources (Tester, 2006). Geothermal resources designated as EGS include those that are not currently in commercial production and require stimulation or enhancement. EGS excludes high-grade hydrothermal resources, but includes conduction-dominated or petrothermal systems, low-permeability resources in sedimentary and basement formations, and geopressured, magmatic, and low-grade unproductive hydrothermal resources. In the doublet system of production and injection wells, EGS concepts would recover thermal energy contained in subsurface rocks by accessing an open system of interconnected fractures through which water can be circulated down injection wells, heated by contact with the rock, and returned to the surface through production wells. In the U.S. Department of Energy's recent report, "Pathways to Commercial Liftoff: Next-Generation Geothermal Power" (Blankenship et al., 2024), EGS is defined as a subsurface circuit of multiple wells and fractures containing a fluid that is heated by the geothermal resource through direct contact with the resource. With respect to reused wells, Santos (2022) classifies EGS as an open-loop system in which the retrofitting of hydrocarbon wells for geothermal energy production has been explored as a technology option to extract heat, particularly from low-permeability reservoirs, at viable and economically potential temperatures. Unlike the conventional geothermal system (i.e., hydrothermal energy), which requires porous and naturally fractured reservoirs limiting the development of geothermal energy to certain geological and geographic locations, the EGS system is believed to enable the development of geothermal energy in the absence of porous and permeable reservoirs.

In many low permeability reservoirs, drilling will not necessarily open up a geothermal reservoir from which geothermal energy production is economically viable without further measures (Huenges, 2013). Well stimulation to increase the productivity and injectivity of geothermal wells then becomes the solution. To date, there are at least three types of stimulation technologies used in Enhanced Geothermal Systems (EGS) that have been adopted from the oil and gas industry. The three techniques are described as follows:

A.1. Hydraulic treatments

Hydraulic stimulation treatments may be divided into hydraulic shearing and hydraulic fracturing treatments. In both cases fluid is injected into a low permeability rock. In hydraulic shearing treatments the pressure is typically kept below the hydraulic fracturing pressure as the target is to induce a shear displacement of existing fractures/fracture networks to increase their permeability by self-propping of the rough displaced fracture surfaces. Hydraulic fracturing is a process through which one or multiple fractures are created mechanically in the rock by fluid pressure increase. In hydrocarbon reservoirs this allows the natural gas or oil trapped in low permeability subsurface formations to move through those fractures to the wellbore from where it can then flow to the surface. Hydraulic fracturing can both increase production rates and increase the total amount of gas that can be recovered from a given volume of rock. First, a fluid is injected into the target formation by injection pumps until the formation breakdown pressure is reached and a fracture starts to grow from the well. Once the fracture is created the fracturing fluid carries proppant (e.g., well sorted sand or ceramics) into the hydraulic fracture to keep it open after fracture closure to allow the oil/gas/water to flow towards the well. While water and sand are the main components of hydraulic fracture fluid, chemical additives are often added in small concentrations to improve fracturing performance (Speight, 2019). Hydraulic fracturing treatments are performed as waterfracs, gel proppant fracs, or something in between called hybrid fracs (Sharma et al., 2004). The procedures are well known in the hydrocarbon industry (Shaoul et al., 2007a, b) and in EGS

(Hettkamp et al., 2004; Baumgärtner et al., 2004; Schindler et al., 2008). The followings are the classification of hydraulic fracturing techniques:

- ### Waterfrac treatments

Waterfrac treatments are applied in the low permeable or impermeable rocks by injecting large volumes of water to create long fractures in the range of 100+ m with a small aperture (approximately 1 mm), and hence low conductivity. The success of the treatment depends on the self-propping of the rock and on the potential for shear displacement or on the capability to transport proppants with the injected water. High flow rates seem to be beneficial for the fracture performance, even if the intervals are limited in time. The proppants may be added in the fluid during the high rates to improve proppant transport (Zimmermann and Reinicke, 2010).

- ### Gel-proppant treatments

Gel proppant treatments are used to stimulate a little bit higher permeability reservoir with cross-linked gels (to reduce fluid leak-off and to transport proppants) in combination with proppants of a certain mesh size. The produced fractures have a shorter length of about 50 - 100 m, but a larger opening of up to 10 mm compared to water frac treatments. The extreme form of gel-prop proppant treatments are frac-and-pack treatments, which generate very short (~10 m) and very wide (~20 mm) fractures that are mainly used to avoid the wellbore skin in high permeability reservoirs. Gel-proppant treatments are typically more expensive compared to water frac treatments (Zimmermann and Reinicke, 2010). Gel-proppant treatments begin with a data FRAC (minifrac) to obtain information on the friction and tortuosity of the perforated interval. The main fracturing treatment, which follows the near-wellbore minifrac test, is performed by injecting gel and proppant into the fracture with a stepwise increase of the proppant concentration. The result of the treatment (propped fracture height, width and lengh) depends mainly on the injection rate, the proppant concentrations and their variation as a function of time (Huenges et al., 2013).

- ### Hybrid fracturing treatments

In hybrid fracturing treatments, slickwater is pumped first to generate a fracture. Then, a gel pad with cross linked gel is injected, followed by proppants or sand of a certain mesh size with a cross-linked gel to fill the fracture (Huenges, et al., 2013). The viscosity of the gel is between slickwater (used in waterfrac treatments) and cross-linked gel (used in gel-proppant fracturing treatments). This method can be applied to low-to-intermediate-permeable reservoirs. Fracture dimensions are typically in between gel-proppant and waterfrac treatments (Zimmermann et al., 2011).

- ### Multi-stage stimulation vs. massive open hole stimulation

The goal of multi-stage stimulation is to increase the surface area of the reservoir in contact with the wellbore. The idea of multi-stage stimulation is to create/stimulate multiple fractures in the target reservoir along the wellbore, as shown in Figure A.1. Multi-stage hydraulic fracturing with multiple perforated zones is most commonly demonstrated in cased wells. Open-hole multi-stage stimulations are possible, but more challenging due to potential crossflow around the packers through natural fracture networks (e.g., Hofmann et al., 2021). The growth of multi-stage fracturing has increased due to completion technology that can effectively place fractures at specific locations in the wellbore.

Prior to the development of the custom-designed system, the only options for completing an open-hole well were uncased holes or slotted or perforated liners. The development of a system that sets in the open hole provides mechanical diversion and allows multiple fractures to be performed along the entire open hole system with the benefit of cost and time savings. An open-hole mechanical packer system is capable of withstanding high differential pressures with fracturing ports located between the packers. Open Hole Multi-Stage Assembly (OHMSs) use hydraulically set mechanical packers to isolate sections of the wellbore.

Multi-stage hydraulic fracturing in cemented liners requires mechanical isolation in the liner by setting bridge plugs using pump-down wireline or coiled tubing (CT), followed by perforating and then fracturing the well to access the reservoir. This process is then repeated for the number of simulations desired for the production section of the well. After all stages are completed, CT is used to drill out the composite plugs and regain access to the bottom of the well. Compared to open hole stimulations production from this method can also be limited because cementing the well closes many of the natural fractures and fractures that would otherwise contribute to overall production. However, it is much more controllable than open hole packers.

Massive stimulation of a large stimulated reservoir volume (SRV) with significantly higher injection volumes and treatment times, as shown in Figure A.1, is typically performed in an uncased well. Typical examples are the Soultz-sous-Forets and Basel EGS (Figure A.2).

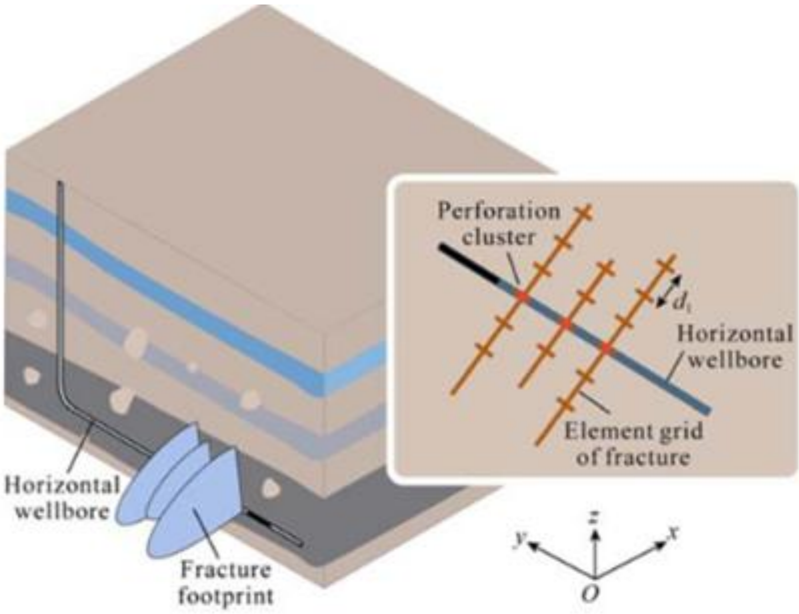

Figure A.1: Schematic diagram of multi-stage hydraulic fracturing (Jinzhou, 2017).

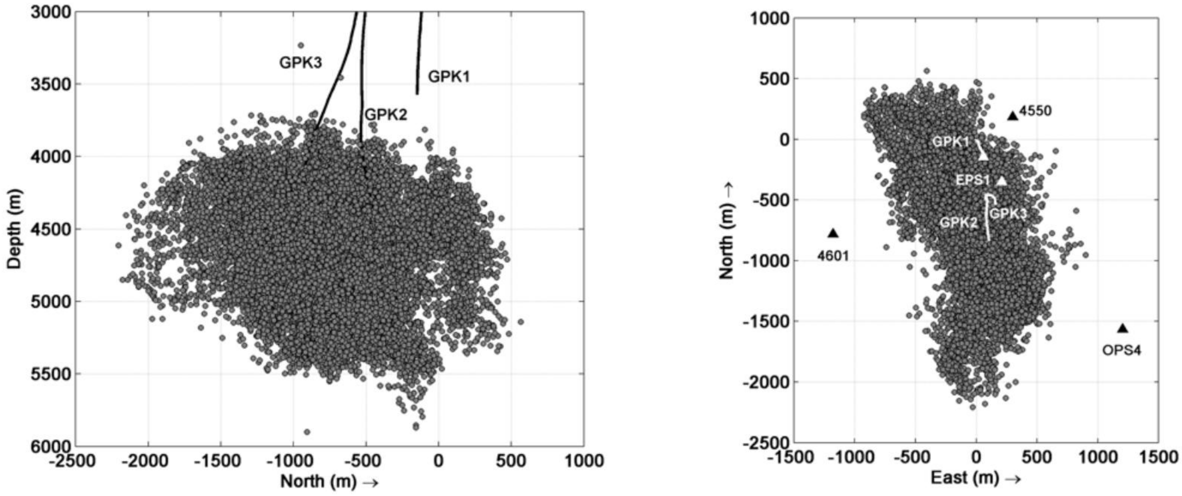

Figure A.2: Seismicity associated with the massive stimulation carried out at GPK-2 and GPK-3 of Soultz-sous-Fôrets in 2003. (a) Vertical view and (b) map view of the seismicity. The downhole seismic stations are represented by triangles on the map view. More than 21,000 events were located, and they are the starting point for the joint hypocenter determination and multiple analysis (Michelet et al., 2007).

A.2. Chemical treatments

Chemical stimulation techniques were originally developed more than a century ago to increase or restore oil and gas well production rates and have been applied to geothermal wells for the past 20 years (Portier, 2007). Acid stimulation jobs are designed to cleanse (pre-existing) fractures by dissolving fill materials (secondary minerals or drilling mud) and mobilising them for efficient removal by flow transport. By dissolving acid-soluble components in subsurface rock formations or removing material at the wellbore surface, the flow rate of oil or gas from production wells or the flow rate of oil displacement fluids into injection wells can be increased. The most common acids used in conventional acidizing treatment are Hydrochloric (HCL), Hydrofluoric (HF), Acetic (CH_3COOH), Formic (HCOOH), Sulfamic (H_2NSO_3H), and Chloroacetic ($ClCH_2COOH$). Acid washing is performed at low pressures. Depending on the purpose of the treatment and on the targeted formation, acidizing is divided into the following classifications:

- **Matrix acidizing**

This process targets the rock matrix. It is performed below fracturing pressure and is normally used for the removal of skin damage associated with drilling, work-over, well killing or injection fluids and to increase formation permeability in undamaged wells.

- **Fracture acidizing**

Fracture acidizing is performed above the fracturing pressure. Due to the reactive nature of the fluid, the addition of acid can dissolve and remove primary and secondary minerals (scale) that seal existing fractures or it can dissolve existing minerals at the fracture surface of new hydraulic fractures or existing natural fractures. The goal is to create flow paths that stay open also after fracture closure due to etching of the fracture surfaces.

A.3. Thermal treatments

Thermal stimulation treatments are used to increase the productivity or injectivity of a well by either increasing the permeability in the vicinity of the wellbore, which may have been reduced by the drilling operation itself (drill cuttings or mud clogging feed zones), or by opening hydraulic connections to naturally permeable zones that have not been intersected by the wellbore. This can occur either by reopening existing, possibly sealed fractures, or by creating new fractures through thermal or additional hydraulic stresses. This treatment type has been used in high temperature systems associated with volcanic activity. Stimulation typically begins with water circulation through the drill string, followed by pumping cold water into the wellbore. Injection may be interrupted by intervals of non-activity during which the well is allowed to heat up to its natural temperature. The injection of cold water leads to a cooling of the rock in the near wellbore environment, or adjacent to existing natural or induced fractures. The cooling of the rock matrix induces a tensile component of stress (thermo elastic stress) near the injection well or adjacent to the injection surface (fractures). The magnitude of this thermally induced tensile stress depends on the thermal and elastic rock properties, and the difference between the initial reservoir temperature and the temperature of the injected fluid (Zimmermann et al., 2011). In the end, a combination of thermally induced tensile stresses and pressure-induced tensile stresses can increase the permeability of existing fractures and create new ones (Huenges, 2013).

The workflow of the Enhanced Geothermal System technology is described in Figure A.3.

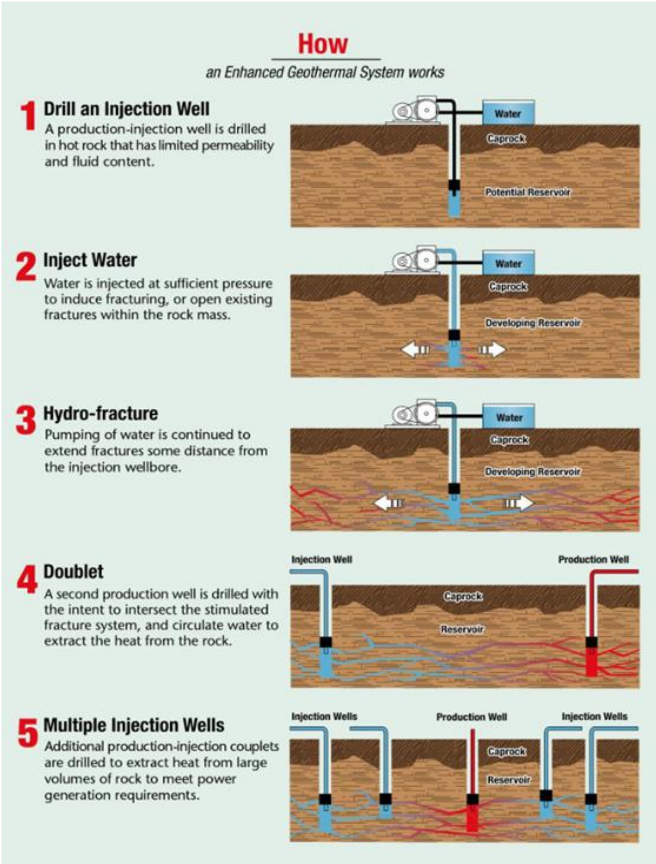

Figure A.3: The flow of developing EGS (sourced from https://www1.eere.energy.gov/geothermal/pdfs/egs.pdf).

B. Lessons learned

B.1 Result of generic modelling of reference site Groß Schönebeck

Christi et al. (2025) conducted numerical simulations including sensitivity analysis using the data set from Groß Schönebeck geothermal research site. The key finding and implication are as follows:

B.1.1 Insight from numerical modelling

The calibrated, matrix-dominated EGS model accurately reflects the observed performance of well E GrSk 3/90 during the injection test conducted after the initial water fracturing in 2003, and during the cross-flow tests conducted between June 2011 and November 2013. Consistent results between the model and the field-measured data demonstrate this. This inspires confidence in the use of the model for designing a fracture-dominated EGS approach. For a further multi-fracture design, however, fracture-driven well placement is used, as proposed by the multi-stage fracture concept for horizontal, parallel doublet wells. While the initial well placement is guided by the desired fracture half-length, the final location is determined by the outcome of the stimulation process and the resulting fracture dimensions. Regarding Groß Schönebeck's role as a pilot site, it demonstrates the efficacy of stimulation methods in a similar geological environment to that targeted by the EGS concept, consisting of the Rotliegend formation, the Dethlingen sandstone, the Sub-Havel conglomerate, and the upper part of the Permo-Carboniferous volcanic section.

B.1.2 Permeability of targeted reservoir is a dominant factor for EGS system

Based on the Groß Schönebeck pilot study, the degree of uncertainty is associated with the permeability of the rock matrix within the Dethlingen formation and the Havel subgroup. Formation damage caused by drilling in well E GrSk 3/90 means that the initial gas lift test is not representative of the permeability of the Havel subgroup and the Dethlingen formation. Ideally, initial well testing or injection test should be conducted to determine the reservoir properties. Analyses show that the permeability of the Havel formation significantly influences both the Productivity Index (PI) and the Injectivity Index (II). This is followed by fracture permeability and fracture width in the associated induced fractures in both the injection and production wells, particularly those generated by massive water fracturing treatments It should be noted that, in EGS systems, the productivity of the reservoir (aside from temperature) is a driver of the thermal output of the EGS systems.

B.1.3. Well completion in relation to the characteristics of the reservoir

The range of temperatures in the reservoir has a significant impact on identifying the optimal target depth for the development scenario. It is also noteworthy that the options for liner materials available at certain temperatures offer flexibility. Carbon steel liners are typically used for geothermal temperatures above 150 °C, while corrosion-resistant, non-metallic alternatives can be used for temperatures below 150 °C. In Groß Schönebeck, for example, the presence of elevated copper concentrations in Rotliegend formation fluids poses a significant challenge to EGS development, making carbon steel completions unsuitable (Regenspurg, 2015). Further testing of the liner material is required and data on the reservoir's condition and characteristics must be provided to facilitate appropriate material selection recommendations. In this context, the integrity of the well completion, which is in direct contact with the reservoir, significantly impacts the substantial investment required for geothermal project development.

B.2 Strategic recommendations for EGS deployment based on reference site Groß Schönebeck

This study demonstrates the significant potential of repurposing existing geothermal and hydrocarbon wells for enhanced geothermal systems (EGS). This approach offers cost savings by reducing exploration and drilling costs for the injection well, as well as repurposing the well for monitoring purposes. However, realizing this potential requires careful consideration of the opportunities and limitations, as well as a focused optimization strategy.

Key takeaways:

- Repurposing is feasible: The successful assessment of well Gt GrSk 4/05 (A2) confirms the technical viability of reusing hydrocarbon wells for a fracture-dominated EGS, providing a step-by-step guide for similar projects.
- Significant Performance Gains: Shifting to a fracture-dominated system with 16 fractures demonstrably increases productivity (PI & II by a factor of 16) compared to the matrix-dominated approach.
- Sustainability is a critical challenge: While initial productivity is promising, achieving long-term, sustainable heat extraction is hindered by thermal breakthrough and declining power capacity, stemming from limited well spacing and fracture stages. This highlights the importance of balancing productivity with reservoir longevity.
- This study validates the promise of hydrocarbon well repurposing for EGS. However, long-term success hinges on a dedicated effort to address the identified sustainability challenges and optimize stimulation, reservoir contact, and material performance. This requires a holistic approach that combines advanced engineering, reservoir modeling, and material science to unlock the full geothermal potential of the Rotliegend formation particularly in the North German Basin.

Further investigation is crucial in the following areas:

- Fracture sustainability: ensure the longevity and connectivity of induced fractures.
- Stimulation optimization: enhance fracture half-length and well spacing to delay thermal breakthrough.
- Lateral expansion: utilize longer horizontal sections to accommodate more fractures and increase reservoir contact.
- Matrix integration: Explore multifrac development strategies within lower permeability matrix reservoirs to maximize reservoir utilization.
- Material science: develop well completions resistant to electrochemical reactions to avoid productivity decline due to severe wellbore scalling.

B.3 Conclusion on model validation and feasibility study for repurposing existing wells for EGS development at the Groß Schönebeck site.

The EGS development workflow based on the EGS model validation and feasibility study at the Groß Schönebeck site is summarized as follows (Figure B.1).

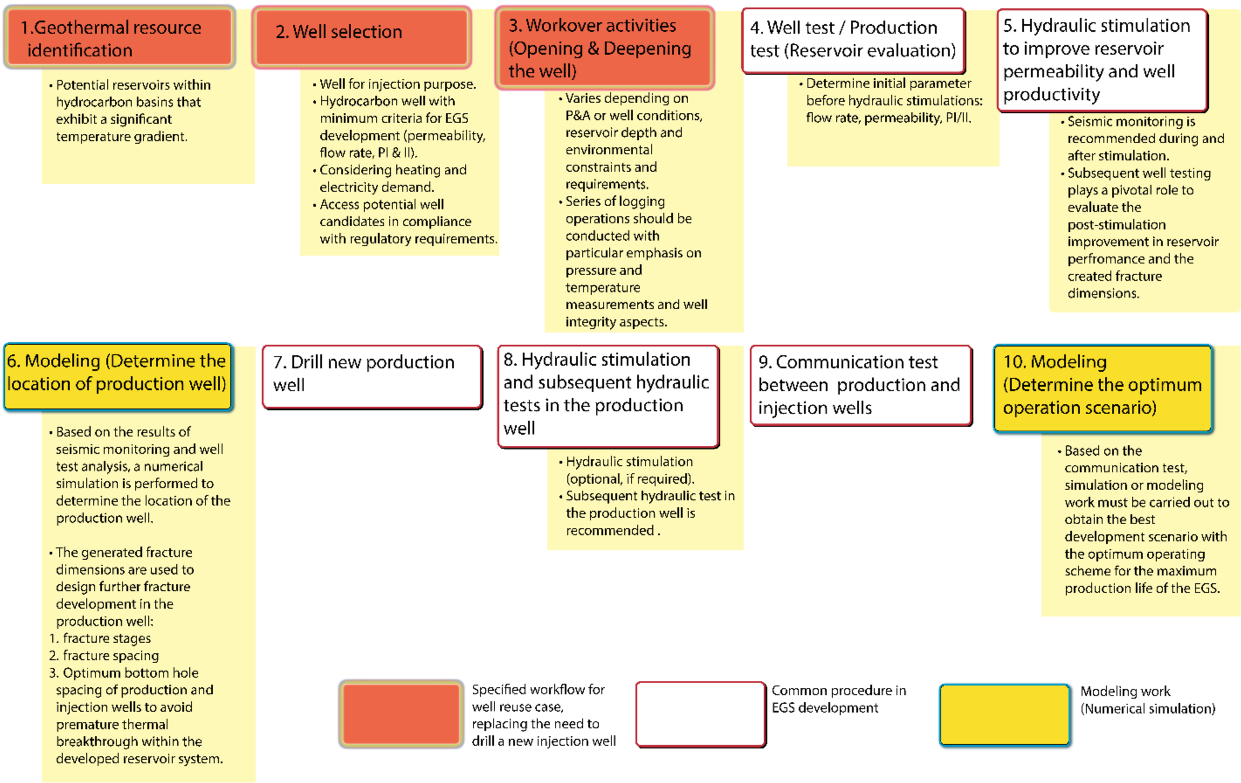

Figure B.1: Workflow for reusing a hydrocarbon well for EGS development, based on model validation at the Groß Schönebeck site (Christi et al., 2025).

C. Requirements to reuse hydrocarbon wells as Enhanced Geothermal Systems

Review of the literature and sensitivity analysis study revealed that the screening criteria for potential geothermal resources in a hydrocarbon environment, which could be developed using EGS technology, are based on four main characteristics of the reservoir: temperature, in-situ permeability or transmissivity of the reservoir rock, flow rate, and Productivity (PI)/ Injectivity (II) indices. The initial permeability, flow rate, PI and II provide the basis for determining whether enhanced geothermal systems (EGS) are required and, if so, this is then followed by determining the stimulation techniques that should be employed in relation to the anticipated production rate. However, temperature plays a pivotal role in the deployment of EGS technology, particularly for applications such as power generation and heating. In the majority of instances where the reuse of hydrocarbon wells for geothermal energy production has been successfully demonstrated with EGS technology (Soultz-sous-Forêts (Aichholzer et al., 2019) and Blue Mountain (Norbeck et al., 2023)), the temperature has exceeded 150 ℃, which is the typical threshold for electrical power generation of the medium enthalpy system (Muffler and Cataldi, 1978; Haenel et al., 1988). The temperature is a pivotal factor that encompasses the geology of the reservoir in terms of rock type. As previously stated in the description of technology, EGS allows for the unrestricted development of geothermal resources, irrespective of the rock types that comprise the reservoir. This is the main advantage of EGS. However, this presents a unique challenge in the application of stimulation methods.

In the context of the TRANSGEO project, which involves the participation of five countries, the temperature criteria are adapted in accordance with the demand of heating in each country. Accordingly, a minimum temperature of 100 ℃ has been established as the threshold for implementing EGS for heating purposes. The scale of the project is dependent upon the scale of the market that must cover the substantial upfront investment required for EGS, which is relatively high when compared to other available technological options.

For the reuse cases, the diameter of the bottom hole represents a critical parameter or determining the possibility of reusing an old hydrocarbon well as an injection or monitoring well for developing an EGS system, as described in the workflow of EGS technology. In addition to the significance of well integrity, the condition of the given well is of paramount importance. The impact of well bottom-hole diameter has been investigated through numerical simulation and sensitivity analysis in the present study. While the impact is not substantial in the context of well performance, as indicated by its direct influence to PI and II, this decision should be made with consideration of the flexibility for well rehabilitation and modification. Consequently, a larger casing diameter will facilitate the installation of liners for side-tracking or deepening of existing wells, as well as the deployment of injection strings for stimulation purposes, downhole seismic geophones, or logging tools. The workover of abandoned and partially abandoned wells has been a crucial aspect in the workflow of EGS implementation. The actual cost of the workover activity will depend on the operation required to modify the well. In this context the depth of the targeted reservoir and the length of the wellbore are the important parameters for estimating the cost. The review of reservoir properties and wellbore characteristics from 70 EGS projects worldwide and the required parameters to reuse hydrocarbon wells are summarized in Table C.1.

Parameters	Unit	Max	Median	Min	Requirement to reuse hydrocarbon wells with EGS technology
Reservoir Depth	m	5000 (Ultra deep case ~ 9000)	3000 - 4000	70 - 450	>1000
Reference	**[Max]** Soultz, United Downs, (Ultra deep case: KTB) **[Median]** Groϸ Schönebeck, Horstberg, St. Gallen, New Berry, Paralana, Boulliante, Lardarello, Fenton Hill, Northwest Geyser, Pohang, Reykjanes (IDDP 2), KTB, Unteraching, Matouying **[Min]** Mosfellssveit (Reykir), Fjälbacka, Falkenberg, Hachimantai				
Reservoir Temperature	°C	250 - 400	100 - 150	16	> 140
Reference	**[Max]** Bacman, New Berry, Cooper Basin (Habanero & Jolokia), Hijiori, Krafla, Baca, Sumikawa, Salak, Fenton Hill, Geyser, Northwest Geyser, Leyte, Hellisheidi, Reykjanes (IDDP-2), KTB **[Median]** Groϸ Schönebeck, Otaniemi (Helsinki Project), St. Gallen, Bruchsal, Unterhaching, Altheim, Seltjarnarnes, Raft River, Geldinganes, Mezőberény **[Min]** Fjälbacka				
In-situ Permeability	m^2	3.94769E-12	5.05E-16	9.8E-20	$<10^{-15}$
Reference	**[Max]** Klaipėda **[Median]** Groß Schönebeck, Salak **[Min]** Lardarello				
Flow Rate	L/s	150	76	~10	<50
Reference	**[Max]** Unteraching, Boulliante (after stimulation) **[Median]** Soultz, Landau (after stimulation) **[Min]** Horstberg, Le Mayet, Paralana, Hijiori, Falkenberg, Northwest Geyser, Fjälbacka (before stimulation)				
Initial productivity Index	L/s/MPa	35	-	~0.1	< 10
Reference	**[Max]** Rittershoffen **[Min]** Soultz, Seltjarnarnes				
Initial injectivity Index	L/s/MPa	21	9.7	0.2	< 10
Reference	**[Max]** Mindanau **[Median]** Bacman **[Min]** Soultz				
Bottom Hole Diameter	inch	10.75	7	2.9	>=7
Reference	**[Max]** Salak **[Median]** Hannover, St. Gallen, Paralana, Unterhaching, Krafla, Sumikawa, Northwest Geyser, Tiwi, Hellisheidi, Olympic Dam, Raft River, Blue Mountain **[Min]** Ogachi				

Table C.1: Required parameters to reuse hydrocarbon wells with EGS technology based on literature review and sensitivity analysis study.

D. Workflow to reuse hydrocarbon wells as Enhanced Geothermal Systems

The workflow of EGS is presented in the following cases which reflect the choice of repurposing hydrocarbon wells as injection and monitoring wells.

Option 1 (reference site Groß Schönebeck): EGS with single stimulation in deepened well

1. Site preparation (5-10 days, depending on location)
2. Mobilisation and rig up (10 days)
3. Exchange wellhead (christmas tree) with blow out preventer (BOP) (2 days)
4. Run in hole and replace borehole fluid (2 days)
5. Drill out cement (1 day, for each additional cement plug add another 2+ days)
6. Deepen hole (50 - 250 m/day, depending on geology)
7. Logging (cement bond log, casing wall thickness, full logging suite of open hole [2 days])
8. Complete newly drilled section (slotted liner [2 days/km] or open hole or cemented liner to improve well integrity)
9. Hydraulic tests before stimulation (4 days)
10. Stimulation with injection string and packers and seismic monitoring (2 days)
11. Hydraulic tests after stimulation (4 days)
12. Drill new well into seismic cloud

Option 2 (reference site Blue Mountain): EGS with horizontal side-track and multi-stage stimulation

1. Site preparation (5 days)
2. Mobilisation and rig up (10 days)
3. Exchange wellhead (christmas tree) with blow out preventer (BOP) (2 days)
4. Run in hole and replace borehole fluid (2 days)
5. Drill out cement (1 day, for each additional cement plug add another 2+ days)
6. Set whipstock in 9 ⅝" (13 ⅜") casing and mill out window with 8 ½" (12 ¼") bit (5hr/km whipstock in and set + 5hr/km string out, 5hr/km in with mill bit, 24hr milling, 5hr/km out with mill bit) for a 7" production casing (or 8 ½" intermediate casing + 7" production liner)
7. Run in hole and deviated drilling to target formation with directional bottom hole assembly (RIH 5hr/km + 50-250 m/day depending on geology)
8. Logging (cement bond log, casing wall thickness, full logging suite of open hole [2 days])
9. Run and cement intermediate casing (2 days/km casing)
10. Run in hole and drill horizontal section with directional bottom hole assembly (RIH 5hr/km + 50-250 m/day depending on geology)
11. Logging (cement bond log, casing wall thickness, full logging suite of open hole [2 days])
12. Run and cement production casing/liner (2 days/km casing)
13. Plug and perf stimulation with seismic monitoring (200 m/hr RIH, 1 day stimulation, pull out of hole 200 m/hr)
14. Hydraulic tests after stimulation (4 days)
15. Drill new well into seismic cloud

Option 3 (reference site Soultz-sous-Forêts): Seismic monitoring well

1. Borehole investigation to confirm the depth and accessibility of the depth interval where the borehole geophone is to be positioned. This includes the necessary logging, such as a dummy tool or calliper test, to ensure that there is no obstruction to the tool during RIH.
2. Pressure and temperature measurement to confirm the downhole temperature and water level measurement. This is to confirm the downhole condition with the borehole geophone specification.
3. Run in hole and installation of borehole geophone.

E. Feasibility analysis

E.1 Technical feasibility

The geothermal resource at Groß Schönebeck exhibits a maximum attainable subsurface temperature of approximately 150°C at a depth of 4.3 km. This falls within the lower boundary of high-enthalpy geothermal systems. Successful EGS development necessitates overcoming several technical challenges. Leveraging existing gas exploration wells offers a significant cost advantage over new drilling, potentially reducing capital expenditure. Achieving commercial viability requires a specific well design and stimulation approach. The current development concept, informed by the Blue Mountain project, necessitates wells with a bottom-hole liner diameter of at least 7", employing a multi-stage fracturing concept coupled with parallel horizontal wells (a minimum of one injection well and one to two production wells). However, attaining a sustained flow rate of at least 180 m^3/hour at this depth is challenging, given the resource's average temperature gradient and depth.

Furthermore, the efficacy of current stimulation techniques is limited by the contact surface area of induced fractures, potentially leading to rapid thermal breakthrough. Consequently, the application is currently more suited to direct heat utilization rather than electricity production. Achieving sufficient power output for electricity generation would require higher flow rates (>180 m^3/hour), necessitating longer lateral sections and fracture lengths – exceeding the limitations of the current technical approach adopted from Groß Schönebeck EGS pilot site.

E.2 Economic feasibility

An economic model was developed based on an EGS configuration utilizing one (reuse) injection well, two production wells, and 16 multi-stage fractures located 50 meters from the district heating facility. The estimated capital expenditure is €34.4 million, comprising:

- Drilling Costs (2 wells x 5.5km @ €2000/m): €22.0 million
- Injection well workover & surface facility costs: €4.4 million
- Stimulation Costs: €8.0 million
- Annual operational and maintenance costs including personnel, are estimated at €1.0 million
- Debt – equity ratio: 80% - 20%
- Interest rate (loan): 16%
- Income tax: 25%
- Depreciation period: 30 years

The model projects a gross thermal power output of 8.6 MW, with a net output of 5.4 MW after accounting for pumping parasitic load of 3.2 MW for 180 m^3/hour production rate. A discounted cash flow model was simulated over a 30-year project lifespan. The model incorporates a sensitivity analysis with the Internal Rate of Return (IRR) ranging from 1% to 16%, with the tariff adjusted to satisfy the IRR range. Results indicate:

- Achievable Tariff: €0.18/kWh to €0.28/kWh for the range of IRR of 1 – 16%
- Payback Period: 5 years (at 16% IRR) to 16 years (at 1% IRR)

The viable heating tariff based on the above assumptions currently exceeds the average district heating price in Germany (€0.12/kWh). To achieve an economically viable EGS project, further work is required to optimize well design and stimulation techniques. The aim of this will be to reduce drilling costs and maximize production rates to generate more thermal power. Further investigation into cost-reduction strategies and large-scale heat market opportunities is recommended to enhance the economic viability of this project.

E.3 Legal feasibility

In terms of legal feasibility, developing EGS requires drilling at least one production well, which extends the exploitation area and often requires an extended exploration permit. Although the reuse of wells could potentially reduce the time allocated for drilling an exploratory and an injection well, the permitting process will take longer, taking into account the uncertainty of the time taken for exploration and land acquisition.

E.4 Typical commercial EGS development

Beyond the Soultz pilot research initiative, Fervo Energy is advancing commercial Enhanced Geothermal Systems (EGS) projects in the USA at the Cape geothermal project (Fercho et al., 2025). These projects are strategically focused on high-temperature reservoirs characterized by a geothermal gradient of approximately 80°C/km. Well designs involve drilling to a total depth of approximately 2.8 km, incorporating 1.5 km of horizontal lateral wellbore to maximize reservoir contact. At these depths and temperatures, the projects are projected to achieve economic viability for electricity generation, representing a key step towards commercializing EGS technology.

In contrast, the North German Basin presents a different scenario. While characterized by lower temperature gradients, drilling into sedimentary rock is generally faster and easier than drilling into granite. However, achieving sufficiently high temperatures will require deeper wells, and sustained high production rates will necessitate significant pumping. Consequently, from a technology readiness perspective, EGS development in this region remains in the development phase, with future projects potentially following a phased approach similar to the Soultz research pilot site.

F. References

Aichholzer, C., Duringer, P., & Genter, A. (2019). Detailed descriptions of the lower-middle Triassic and Permian formations using cores and gamma-rays from the EPS-1 exploration geothermal borehole (Soultz-sous-Forêts, Upper Rhine Graben, France). *Geothermal Energy*, *7*(1), 34.

Baumgärtner, J., Jung, R., Hettkamp, T., and Teza, D. (2004) The status of the hot dry rock scientific power plant at *Soultz-sous-Forêts. Zeitsschrift für Angewandte Geologie*, 2, 12-16.

Blankenship, D., Gertler, C., Kamaludeen, M., O'Connor, M., Porse, S. (2024). Pathways to Commercial Liftoff: Next-Generation Geothermal Power. U.S. Departement of Energy.

Christi, L. F., Sass, I., Norden, B., Blöcher, G., Zimmermann, G., & Hofmann, H. (2025). Repurposing of hydrocarbon wells for Enhanced Geothermal System (EGS) development. *Geothermics*, *128*, 103268.

Christi, L.F., Hofmann, H., Zimmermann, G., Sieron, K., Kurevija, T., & Macenić, M.: Feasibility study for the pilot site Groß Schönebeck (North German Basin). Technical Report, Interreg-Central Europe, (2025b). URL: https://www.interreg-central.eu/wp-content/uploads/2026/01/2-3-8-Feasibility-Study-Gross-Schoenebeck.pdf.

Fercho, S., Norbeck, J., Dadi, S., Matson, G., Borell, J., McConville, E., ... & Rhodes, G. (2025, February). Update on the geology, temperature, fracturing, and resource potential at the Cape Geothermal Project informed by data acquired from the drilling of additional horizontal EGS wells. In *Proc. 50th Workshop on Geothermal Reservoir Engineering https://pangea. stanford. edu/ERE/pdf/IGAstandard/SGW/2025/Fercho. pdf (Stanford University, 2025)*.

Hettkamp, T., Baumgärtner, J., Baria, R., Gerard, A., Gandy, T., Michelet, S., & Teza, D. (2004). Electricity production from hot rocks. In *Proceedings, 29th Workshop on Geothermal Reservoir Engineering, Stanford University, Standford, California, USA*.

Huenges, E., Kohl, T., Kolditz, O., Bremer, J., Scheck-Wenderoth, M., & Vienken, T. (2013). Geothermal energy systems: research perspective for domestic energy provision. *Environmental Earth Sciences*, *70*, 3927-3933.

Hofmann, H., Zimmermann, G., Zang, A., Aldaz Cifuentes, S. R., Cesca, S., Heimann, S., ... & Mignan, A. (2021). Hydraulic Stimulation Design for Well RV-43 on Geldinganes, Iceland. In *World Geothermal Congress 2020+ 1*.

Hofmann, H., Hölzel, M., Hoyer, S., Werkl, P., Brives, J., Christi, L.F., Liu, Y., Blöcher, G., Petrova, E., Kurevija, T., Perković, L., Macenić, M., Sedlar, D.K., Prkič, I.S.M., Sieron, K., Fedor, F., Castro, C.C., Szanyi, J., Kovács, J., Svetina, M. Engineering workflows for retrofitting abandoned wells. Technical Report (2025). Interreg-Central Europe. URL: https://www.interreg-central.eu/wp-content/uploads/2025/02/TRANSGEO-D1.1.6-Engineering-Workflows-FINAL-December 2024.pdf.

Jinzhou, Z. H. A. O., Xiyu, C. H. E. N., Yongming, L. I., Bin, F. U., & Wenjun, X. U. (2017). Numerical simulation of multi-stage fracturing and optimization of perforation in a horizontal well. *Petroleum Exploration and Development*, *44*(1), 119-126.

Michelet, S., & Toksöz, M. N. (2007). Fracture mapping in the Soultz-sous-Forêts geothermal field using microearthquake locations. *Journal of Geophysical Research: Solid Earth*, *112*(B7).

Norbeck, J., Latimer, T., Gradl, C., Agarwal, S., Dadi, S., Eddy, E., ... & Woitt, M. (2023, February). A review of drilling, completion, and stimulation of a horizontal geothermal well system in North-Central Nevada. In *Proceedings of the 48th Workshop on Geothermal Reservoir Engineering* (pp. 6-8).

Regenspurg, S., Feldbusch, E., Byrne, J., Deon, F., Driba, D. L., Henninges, J., ... & Schubert, C. (2015). Mineral precipitation during production of geothermal fluid from a Permian Rotliegend reservoir. *Geothermics*, *54*, 122-135.

Santos, L., Taleghani, A. Dhani, Elsworth, D. (2002): Repurposing abandoned wells for geothermal energy: current status and future prospect. Renewable Energy 194, 1288 – 1302.

Sharma, M. M., Gadde, P. B., Sullivan, R., Sigal, R., Fielder, R., Copeland, D., ... & Weijers, L. (2004, September). Slick water and hybrid fracs in the Bossier: Some lessons learnt. In *SPE Annual Technical Conference and Exhibition?* (pp. SPE-89876). SPE.

Shaoul, J., Ross, M., Spitzer, W., Wheaton, S., Mayland, P., & Singh, A. P. (2007, May). Massive hydraulic fracturing unlocks deep tight gas reserves in India. In *SPE European Formation Damage Conference and Exhibition* (pp. SPE-107337). SPE.

Schindler, M., Nami, P., Schellschmidt, R., Teza, D., & Tischner, T. (2008). Summary of hydraulic stimulation operations in the 5 km deep crystalline HDR/EGS reservoir at Soultz-sous-Forêts. In *Proceedings, 33rd Workshop on Geothermal Reservoir Engineering*.

Speight, J. G. (2019). *Shale oil and gas production processes*. Gulf Professional Publishing.

Tester, J.W. (2006) The Future of Geothermal Energy, Impact of Enhanced Geothermal System (EGS) on the United State in the 21st Century: An Assessment by an MIT-Led Interdisciplinary Panel. Idaho National Laboratory, Report ISBN 0-615-13438-6, Idaho Falls.

Zimmermann, G., & Reinicke, A. (2010). Hydraulic stimulation of a deep sandstone reservoir to develop an Enhanced Geothermal System: Laboratory and field experiments. *Geothermics*, *39*(1), 70-77.

Zimmermann, G., Blöcher, G., Reinicke, A., & Brandt, W. (2011). Rock specific hydraulic fracturing and matrix acidizing to enhance a geothermal system—concepts and field results. *Tectonophysics*, *503*(1-2), 146-154.