# Subsurface Located Geothermal Well – Case Study

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# Abstract

The recovery of geothermal energy has become very attractive in the last decades. Advantages like the small footprint, the waste-free and $CO_2$ neutral energy production and the continuous geothermal resource, will highly promote geothermal energy usage soon. This paper presents a case study of a subsurface located geothermal well. The overall approach is to use existing subsurface facilities and construct the geothermal energy recovery system within them.

Currently, the generated power, produced by geothermal energy systems, is more expensive than energy produced from competitive sources, because of the costs associated with the construction of the wellbore. To extend the use of geothermal energy, its recovery costs have to be reduced. The primary wellbore cost driver is the depth. The drilling costs rise exponentially with depth. When situating a geothermal power plant in an underground structure, the temperature at the start point of such a geothermal well is already at an elevated temperature level, and the total amount of meters to be drilled is substantially reduced, thus saving drilling costs.

A primary focus of this paper is, on the one hand, the amount of energy to be recovered and, on the other hand, the technical realization of such a project. The results have shown that the efficiency of subsurface located geothermal wells is higher than for surface located ones. Technical equipment and technology for drilling subsurface are already available today. A case study for investigating the influence of parameters like depth and number of wells is performed. Depending on geology, simulations have indicated that it is from the technical point of view more efficient to drill a deeper well in comparison to drill several shallow subsurface wells. Nevertheless, from the economic point of view, currently, surface drilled wells are more economical.

So far, a drilling rig has never been positioned below ground, and the legal framework is just partially defined so far. This paper presents a case study of a subsurface located geothermal well positioned in existing underground infrastructure. This case study shows the vast potential but indicates the risks and limitations as well.

# Introduction

Geothermal energy is an inexhaustible source of primary energy, spread around the globe in massive amounts, but not equal geographically distributed. Its potential is highest in active tectonic regions. The recovery of geothermal energy requires a small surface footprint, and the extraction is $CO_2$ neutral and almost waste-free. These are just a few reasons for explaining the globally growing usage of this kind of renewable energy resource. The worldwide operating capacity reached 13.5 GW in 2016 as a result of a 5% annual growth in each of the previous years (Renewable Energy Policy Network for the 21st Century, 2017). Geothermal plants are spread across 24 nations. The global electricity and direct heat production from geothermal energy, estimated by the Renewable Energy Policy Network for the 21st Century in 2017, is 157 TWh (Renewable Energy Policy Network for the 21st Century, 2017), with fifty-fifty ratio between usage for electricity and heat. The latest data for Austria report a total primary energy consumption of 372 TWh (Statistik Austria, 2018). 29.5% of the primary energy production is due to renewables. These numbers show that the global geothermal energy production can even not meet the consumption of Austria. Despite the steady growth and the massive potential of the geothermal resource, only a vast percentage is utilized. Currently, the share of geothermal energy in total electricity capacity and generation remains very low. The global installed electricity capacity in comparison to the net generation indicates that just 0.4% of global electricity is generated from geothermal applications. The vast majority is based on fossil fuels. The total share of non-renewables is currently about 77%. Nevertheless, a forecast made by the Geothermal Energy Association (Geothermal Energy Association, 2017) predicts a continuous growth of the installed geothermal capacity, and by 2020 up to 17.6 GW installed capacity is predicted. Currently, a capacity of around 11.5–12.3 GW is planned or under development in 80 countries.

Geothermal energy recovery is geographically diversified. The most significant amounts of installed geothermal electricity generation capacity are in the United States (3.5 GW), Philippines (1.9 GW), Indonesia (1.4 GW), Mexico (1.0 GW), and New Zealand (1.0 GW). The major producers in Europe are Italy (0.9 GW) and Iceland (0.7 GW). By the end of 2014, there were worldwide 612 geothermal power plants operating. Europe experiences a slower development than it could, mainly due to the general lack of awareness of the potential of geothermal energy (Renewable Energy Policy Network for the 21st Century, 2017). Geothermal energy is one of the only renewable energy sources that have the capability of providing base-load electric power, due to its independence on sun, wind, and water. Minimum impacts on the environment are associated with its extraction. Neither $CO_2$ certificates within the European Union Emission Trading System need to be bought, nor expensive invests in technologies to reduce the carbon dioxide emissions are required.

The increasing global energy demand, especially in the non-OECD countries and the continuing environmental policy against climate and air pollution, may boost the geothermal energy recovery in some regions. Extraction of geothermal energy is already a competitive technology in terms of costs compared to other types of renewable and conventional energy sources (World Energy Council, 2013). Depending on the type of power plant, the average costs are between 60 to 80 USD/MWh energy generated. The most significant share of the overall costs of a geothermal power plant is associated with the construction of the wellbore. Costs for drilling may vary, depending on the oil price. A decreasing rig count in the oil industry generates a potential for utilizing drilling rigs for geothermal wells at moderate costs. Nevertheless, the potential of a geothermal cogeneration plan depends on the location of the wellbore and geology. Geothermal systems for electricity generation are just useful if the geothermal gradient is relatively high, and the remaining energy from electricity generation can be used for heating purposes; thus, consumers have to be situated within a certain distance to the plant.

In Austria, the geothermal potential highly depends on the region. Whereas in general, the potential is low in the alpine region, Neogene basins, like the Molasse basin in Upper Austria and the southeastern Styrian basin, provide a significant potential for geothermal cogeneration (Geologische Bundesanstalt, 2020).

## Geothermal Systems

Besides near-surface geothermal systems, like ground heat collectors, shallow borehole heat exchangers, and energy piles, which are specified by target depths of several 10’s of meters up to 150 m, deep geothermal energy recovery systems exist. The temperature at the target depths of deep geothermal systems can reach more than 150 °C and results in increased energy output. Another advantage of deep geothermal systems is that neither daily nor seasonal temperature swings affect the system, which is usually the case up to depths of 10 meters. Deep geothermal energy recovery systems can be further split into hydrothermal and petrothermal systems.

*Hydrothermal systems* are based on the utilization of hot water originating from an aquifer. The energy extraction takes place in a direct way or via a heat pump and used for the feeding of local or district heat networks. Above surface temperatures of 80 °C, the operation of an Organic Rankine Cycle power plant is an option, whereas temperatures above 120 °C enable the usage of the Kalina process. These processes typically employ a so-called hydrothermal doublet. Hot water is produced from a producer well, heat is extracted via a heat exchanger at the surface, and the cooled-down water is reinjected into the same aquifer where it originated. Reinjection guaranties pressure maintenance of the reservoir layer and is often demanded by the authorities (Stober, I., Bucher, K., 2012).

*Petrothermal systems* form the second group of systems for deep geothermal energy recovery. They are independent of aquifers since they recover the heat stored in the formation around the borehole. The primary purpose of petrothermal geothermal systems is the generation of electricity. Depending on geology, the aim is to reach formation temperatures of up to 200 °C. Well depths of several thousand meters are often required in crystalline basement formations. These crystalline formations are naturally fractured, and water, which is artificially added to the formation acts as the circulating fluid, can flow through natural fractures in the formation. Heat is extracted by a doublet arrangement of the two wells (Stober, I., Bucher, K., 2012).

The *deep geothermal probe* is a special type of deep geothermal energy recovery, which uses a closed circulation system in a single wellbore. Recovery is generally lower than in other systems as a result of a low surface area, where heat can be transferred from the surrounding formation to the circulating medium. The formation is cooling down over time because of the heat extraction, depending on the rock properties, which very slowly decreases the performance of the system. Nevertheless, beneficial for the usage of deep geothermal probes is the fact that they can be installed independently on geology without having any risk of environmental pollution or chemical reactions in the formation. Besides, abandoned oil and gas wells can be converted to geothermal energy producers. The deep geothermal probe, or also called the borehole heat exchanger, consists of two concentric pipes and forms a coaxial system. These pipes create two flow paths, one between the inner diameter of the production casing string and the tubing outer wall, the other one inside the tubing. The cold circulating media is injected into the casing-tubing annulus, is heated up due to the increased formation temperature while flowing down the wellbore. At the final wellbore depth, the maximum temperature is reached. The target is to conserve the temperature of the fluid while traveling inside the tubing back to the surface, which can be achieved by using an isolated tubing string. Compared to hydrothermal or petrothermal systems, the energy output of deep geothermal probes is lower, but the investment and maintenance costs are lower too (Stober, I., Bucher, K., 2012).

## Subsurface Location

The costs for drilling a deep wellbore represent the most significant portion of the total costs of a geothermal project. The shares vary widely between 40% (C.Augustine et al., 2006), 50+% (E.Radeberg et al., 2012), and 40 to 95% (S.Thorhallsson, B.M.Sveinbjornsson, 2012) according to reference costs in the literature. Such a vast fluctuation in costs is the result of the uncertainty of geologic data in a project. Moreover, drilling costs are not equally spread all over the world. In remote areas, higher fees are charged by contractors. There are only a few complimentary data about geothermal drilling costs available, especially for the European region. Hence, the industry makes use of data from the oil and gas industry, where several thousand wells are drilled and reported each year. The use of oil and gas drilling data is valid since the equipment and technology used is the same. However, expenditures for geothermal wells are by the factor 2–5 higher compared to hydrocarbon wells, because of larger wellbore diameters, more significant amounts of expensive thermal-conductive cement and completion material. When observing a statistically significant amount of deep wellbores, one can conclude that the costs are increasing exponentially with depth (S.Thorhallsson, B.M.Sveinbjornsson, 2012). The following factors can argue this anomaly:

- • The number of required casing strings increases with depth
- • Drilling rig must consequentially handle higher loads
- • Costs of additional casing strings and cement
- • Lower rate of penetration due to increasing strength and abrasiveness of deeper formations

To get a first estimate for the expected drilling costs of deep wells, already drilled oil and gas wells, as well as geothermal wells, were investigated. Annually published API reports (American Petroleum Institute, 2003) for oil and gas wells in North America provide a profound basis. The average expenditures in the year 2003 for deep wellbores between 4,300 and 5,300 m were 5.17 million USD (S.Thorhallsson, B.M.Sveinbjornsson, 2012). Examples in Europe are the enhanced geothermal system wells GPK-3 and GPK-4 in Soultz, France. They are targeting a bottom hole depth of 5,100 m. Despite the wellbores reach the same depth and were drilled in near vicinity of each other, the drilling costs vary widely. The GPK-3 drilling costs were 6.57 million USD, whereas the drilling costs for GPK-4 were 5.14 million USD. A reason for the difference in cost is the local variation in geology, which frequently leads to drilling problems. In general, one additional casing string for a 5,000 m deep vertical wellbore (five instead of initially four) caused the overall costs to rise by 18.5%. The cost behavior as a function of depth is also the concern of a study performed by the Massachusetts Institute of Technology in 2006 (Massachusetts Institute of Technology, 2006). Figure 1 displays the cost of completed geothermal, oil, and gas wells in the US as a function of depth. It indicates the extraordinary rise in costs for deep wells.

To reduce the drilling costs as the significant cost driver for deep geothermal wells, this case study investigates the effects if the geothermal well is drilled from existing subsurface facilities, like mines, tunnels, or caverns. Significant advantages are a decrease of wellbore length to reach the same target formation, which reduces drilling costs and the reduction of friction pressure losses for circulating the fluid in the geothermal probe. Issues to be investigated are the subsurface space requirements for the drilling rig, logistics, and HSE regulations. In subsurface mining, several mineral extraction methods are applied that create vast caverns. The idea is to position the drilling rig in such a cavern for drilling the geothermal probe, as presented in Fig. 2.

## Challenges In Drilling Rig Selection And Logistics

The idea of positioning the drilling rig in a subsurface cavern comes along with special requirements for the drilling rig.

- Space: The excavation of a cavern is time-consuming and requires high technical and financial efforts if the excavated material cannot be used as a natural resource. Therefore, the selected drilling rig should have a small footprint and height.
- Wellbore depth: To gain sufficient temperature for the geothermal probe, the target depth of the wellbore must not be below 5,000 m, which results in a specific hook load constraint for the drilling rig.
- Power supply: It needs to be taken into account that fuel- or gas-powered electricity generators can only be used concerning some limitations. The hazard potential through ignition or explosion of fuel or other flammable liquids in a closed, subsurface space is very high. Besides, air ventilation and extraction of emerging fumes must be taken into consideration. Drilling rigs with external power supply via the power grid are preferred.
- Circulation system: The drilling mud processing needs to be done in a closed system, because of occasionally occurring gas, which must not escape into the free atmosphere.

The following drilling rigs originating from Central Europe (Germany, Austria) were compared. Table 1 summarizes the technical data of the compared drilling rigs.

- Bauer TBA 200 Deep Drilling Unit
- Bauer TBA 300 Deep Drilling Unit
- Bentec EURO RIG 350t
- Herrenknecht Vertical Deep Drilling Rig Terra Invader 350 Slingshot
- Herrenknecht Vertical Deep Drilling Rig Terra Invader 350 Box-on-Box
- Max Streicher Tiefbohranlage VDD370
- RAG Energy Drilling Bohranlage E200/E202

Table 1
Comparison of technical data on selected drilling rigs. (*1 Dimension originate from a standard blueprint, with no consideration of space optimization, *2 If the diesel generator and tank is not included, the width of the footprint is reduced from 41 m to 33 m)

| | **TBA 200 Deep Drilling Unit** | **TBA 300 Deep Drilling Unit** | **Bentec Euro Standard Rig 350 t** | **Herrenknecht Terra Invader 350 Slingshot** | **Herrenknecht Terra Invader 350 Box-on-Box** | **Max Streicher VDD370** | **RAG E200/202** |
|---|---|---|---|---|---|---|---|
| Hook load | 200t | 300t | 350t | 350t | 350t | 336t | 250t |
| Max. Hook load | | | | | | 377t | 300t |
| Max. Drilling Depth | 3000 m | 5000 m | 6000 m | 5500 m | 5500 m | 5000 m | 5500 m |
| | | | | | | | w/ 3 1/2" DP |
| Power Supply | n/s | 4 × 1 MW diesel generator | n/s | max. 1540kVA per generator | max. 1540kVA per generator | 4 × 852 kW AC generator | 6 × 532 kW diesel generator |
| via grid | n/s | 20 kV | n/s | possible | possible | possible | n/s |
| Footprint | 30 m x 28 m | 33 m x 23 m (*2) | 55 m x 40 m | n/s | n/s | | 85 m x 43 m (*1) |
| | 840 m2 | 759 m2 | 2200 m2 | | | 1224 m2 | 3655 m2 |
| Total height | 33 m | 41 m | 44 m | 46 m | 52 m | 31 m | 41 m |

According to the technical data provided by the drilling contractors and the particular needs, a pre-selection can be done:

The Bauer TBA 300 Deep Drilling Unit convinces with the lowest footprint requirements. The rig is capable of drilling the required target depth and can handle the corresponding loads. Possible power supply via the local grid is also favorable. The derrick is self-erecting. The Max Streicher VDD370 rig shows similar performance data. However, the required footprint is more extensive. Herrenknecht Vertical Deep Drilling Rig Terra Invader 350 Slingshot does not provide information about the needed footprint. A significant aspect of why the rig is nevertheless considered is its unique construction. The slingshot system promises a rig-up of the derrick without the need of a crane; the derrick will erect itself. This can be a crucial benefit in the case of the restricted space in a subsurface cavern. A crane for unloading of the transport units from the trucks is required, however. Moreover, the nominal maximum drilling depth is 500 m deeper than for the other two rigs. If the footprint of the RAG E200/E202 drilling rig can be drastically reduced for subsurface usage, this rig can be included in the above list.

## Hse Aspects

A significant part of the evaluation of a subsurface operating drilling rig is health, safety, and environmental considerations. Factors that are critical for the success of the project are organized in thematic groups, their impact on various operations or the overall project must be assessed, and ultimately measures for the avoidance, or – if it is not possible to avoid these – measures for mitigation have to be defined.

- Transport: One of the most critical aspects of the operation of a drilling rig is transportation. Components and personnel of the drilling rig must be on location in time. Space is often limited, more than ever in a restricted cavern. Thus, careful planning in the two domains is critical. First, the dimensions of the transported object must be evident. Secondly, proper time management must be set up. Moreover, mutual interference between the drilling operation with its overall supply needs (electricity, diesel) and waste products (cuttings) through the mine and the operation of the mine itself must be avoided.
- Limitation of space: A subsurface cavern is limited in space, compared to the less restricted well sites onshore. Access roads too — and from — the caverns are constructed in a way that freedom of movement for regular trucks of haulage contractors is possible. Considerations about the space for storage areas, rig site, accessibility of the rig site, and maneuverability of trucks, cranes, and other vehicles must be made, and issues can be overcome in advance by detailed planning in the preliminary stage of operation.
- Working safety: Considerations for working safety are generally valid in any working environment: in the construction industry, in particular, where operating heavy machinery is a daily routine, movement of heavy loads and exposure to all kinds of emissions are common. Influencing factors, risks, and measures for working safety include especially the use of correct personal protective equipment, potential explosion hazard areas (EX zone), handling of chemicals, the occurrence of dust, sparks, especially during welding work, fire, optical radiation, the release of gas, and working at heights. In a subsurface located workplace, the failure of the light system and ventilation system must be avoided by all means.
- Noise emission: Drilling in a subsurface location benefits the usually affected residents close-by to a drill site, since the generated noise will not escape from the cavern and thus will not have an impact on residents. The only affected group is the drilling crew and other workers present near the drilling rig. However, the noise level must be kept within limits enlisted in the working conditions act.
- Mud losses while drilling: One of the most significant potential risks when drilling a well in a new prospect area. Faults, fracture networks, karstification, or even caverns may lead to drilling mud losses in the drilling process. By gathering and analyzing various geological and geomechanical data, possible thief zones can be identified and the risk mitigated.
- Gas or water influx from the formation: The opposite of fluids leaving the wellbore would be fluids unexpectedly entering the wellbore during drilling, for instance, from gas- or water-bearing layers.
- Interference due to mining operations: To keep costs low, the access from the surface to the cavern will be the same for the drilling rig and its crew as for the regular mine operation, assuming that the mine is still in operation. Activities that occur during the regular operation of the mine might interfere with the

drilling operations in the cavern. Blasting operations are of particular interest since the vibrations might harm the drilling operations.

- Headcount of the workforce: For the dimensioning of rescue and safety equipment, it is necessary to declare a maximum number of employees that are present at the same point in time in the cavern. Ordinary mid-sized drilling rigs require around eight people for operation. During crew change, the amount of people doubles, since both crews are present at the same time. Along with additional employees from service companies or truck drivers, there are about 25 people present at peak hours.
- Mine ventilation: The supply of fresh air for persons and machines is vital. Further tasks of the mine ventilation systems are the dilution of harmful gases and cooling of the working areas, especially inside of the cavern. In the underground, there is always the possibility of the occurrence of poisonous and explosive gases. These gases must be aspirated permanently to ensure the safety of all present employees. The vehicles used in underground mining are equipped with a highly efficient waste gas purification system. Hence, a danger based on the use of combustion engines in the mine is negligible. The exhaust gas coming from the standard trucks, which are delivering the drilling rig and supplies, can be filtered with the mine's ventilation system.

## Heat Extraction Comparison

To estimate the cost/benefit ratio of a single versus multiple deep geothermal wells, a simulator was used for modeling of the thermal processes in the region around and within the wellbore. This simulator was developed by the Chair of Petroleum and Geothermal Energy Recovery at the Montanuniversitaet Leoben (Fruhwirth, R.K., Hofstätter, H., 2016). Conduction, radiation, and convection were considered a mechanism for heat transport. The heat losses in the formation are of course considered as transient since the formation cools down with ongoing heat extraction during the operation of the deep geothermal well. The processes taking place inside the borehole were defined as stationary because variations of the parameters occur on an hourly or daily basis, compared to the transient heat losses that occur for years. The transient earth model is linked to the stationary borehole model via the borehole wall temperature.

To investigate the impact of the borehole completion on the heat extraction, a simulation under ideal conditions – assuming no production casing, hence direct contact of the circulation media with the formation – and real world conditions – a regular API conform tapered casing string – was carried out. Besides the borehole completion, the underlying assumptions are identical for both scenarios. A 5,000 m vertical wellbore is drilled into a homogenous crystalline basement rock; the tubing has an OD of 4 ½ inches and is entirely isolated; geothermal gradient 3 °C/100 m, rock density 2900 kg/m³, heat capacity 710 W/kgK, and thermal conductivity 3 W/mK are constant. The beginning of the wellbore is in a depth of 1000 m, where a temperature of 30 °C is present. The bottom-hole temperature is 180 °C. A circulation rate of 10 m³/h at an injection temperature of 60 °C is chosen.

In Fig. 3, the indirect circulation of the subsurface wellbore under ideal conditions is shown. The red line represents the initial formation temperature $T_e$. The orange line, which represents the temperature of the fluid in the annulus $T_{a,}$ is identical with the dashed dark-blue line, which shows the temperature along the borehole wall $T_w$. The blue line shows the temperature of the fluid inside the tubing Tp. Since the tubing is assumed to isolate entirely, the fluid temperature at the wellhead is 148.3 °C. This kind of borehole heat exchanger causes a reduction of the rock surrounding the wellbore. After one year of operation, the amount of energy that can be extracted will drop to 63%, after 30 years to about 50%. Figure 4 shows the changes in the temperature distributions after an operating period of 30 years. The wellhead temperature will reduce to 103.8 °C.

The parameter study performed shows that the energy extraction rate is following the fluid circulation rate. A higher circulation rate can achieve higher power rate, but at the same time, the formation will cool down faster, and the wellhead temperature will be lower in comparison to a moderate circulation rate.

Figure 5 presents a schematic of the real wellbore drilled from surface (a) and from subsurface (b) and their temperature profiles just after start of production. The schematic shows that the wellbore consists of an anchor, a surface casing and a production liner. The simulation results show that the wellhead temperature is 143.4 °C for the surface well and similar with 144.0 °C for the subsurface well, both at an inflow temperature of 60.0 °C. Temperatures of both cases, especially the resulting temperatures after 30 years of operation, are too low to generate electricity efficiently. For such low temperatures, the efficiency of conversion to electricity is only around 10%. It is more useful to utilize geothermal energy for heating purposes at this stage.

From the investigation of the long-term temperature decrease over time with distance to the borehole wall, it can be concluded that the minimum distance between two geothermal wells must be 116.9 m in order to avoid the mutual influence of the geothermal wells. After 30 years of operation, the temperature at the wellbore wall decreases to 100.6 °C, whereas the undisturbed initial temperature of the formation is present at a distance of 58.46 m.

Assuming a linear increase of heat flow with depth, the heat flow from the formation to the wellbore will be 435 kW for a 6,000 m well. Under consideration of 25% thermal losses, the net thermal energy output will result in 326 kW or earnings of roughly 240,000 EUR for continuous operation over a year. For a 4,000 m well, the thermal energy output will be 84 kW – 20% thermal losses already deducted – thus leading to a sales profit of around 60,000 EUR under similar conditions as before. This concludes that it is not economical to drill several shallow wells instead of one deep.

These potential profits must cover the cost of the construction of the wellbore. Overall, drilling costs are affected by various parameters throughout the entire process, where geology can be defined as the main factor. Even with an accurate knowledge of the expected geology that is going to be drilled, the uncertainty of the financial outcome of the project is still high. Hard and abrasive formations demand high investments into proper drilling equipment since those formations increase the wear of tools, accompanied by slow drilling progress versus depth. Therefore, a first cost evaluation will only indicate a direction where the final costs are heading and should be used with particular caution.

Table 2
compares the costs of a 6,000 m wellbore drilled from the surface with a 5,000 m wellbore drilled from the inside of a cavern. The outside diameter of the production casing is defined to be 7 inches, which can be found in the majority of already drilled geothermal wells (Teodoriu, C., 2015). Three casing strings are installed because of contingency reasons, although the well could theoretically be constructed with one single casing section. But in case of unexpected formations, there is only spare capacity in size.

| **Costs per Section** | **6,000 m Surface** | **5,000 m Subsurface** |
|---|---|---|
| Base Costs | 454.795 | 454.795 |
| Section 1 — Surface | 336.866 | 336.866 |
| Services | 125.913 | 125.913 |
| Material and Consumables | 210.953 | 210.953 |
| Section 2 — Intermediate | 2.547.348 | 2.547.348 |
| Services | 1.307.843 | 1.307.843 |
| Material and Consumables | 1.239.505 | 1.239.505 |
| Section 3 — Production | 4.001.552 | 2.898.135 |
| Services | 2.613.063 | 1.853.245 |
| Material and Consumables | 1.388.489 | 1.044.890 |
| Total Drilling Costs | 7.340.561 | 6.237.144 |
| Difference | | -1.103.417 |
| Wellsite Construction Costs | 200.000 | 4.320.000 |
| Total Costs | 7.540.561 | 10.557.144 |
| Difference | | 3.016.583 |

Table 2: **Economic comparison – surface versus subsurface well construction costs**

The calculation can be separated into two parts. In the first part, the total costs for drilling a well are evaluated and compared. One can see that the 6,000 m wellbore from the surface is almost 18% more expensive than the 5,000 m wellbore, which is drilled from the subsurface. A critical cost factor, which has not been considered so far in the calculation, includes the costs for the construction of the well site. In the case of the subsurface well, the costs for the cavern construction are added to the total drilling costs, whereas for the surface well, the ordinary well-site construction costs are added. With this information, the result has been inverted and seems to be no longer economically attractive. In an optimum scenario, the required cavern will be constructed during the regular mining operation, thus adding no more additional cost for the well site construction of the subsurface located well.

Calculations for different well depths have shown that the savings for 1,000 m of wellbore length are moderate, compared to the costs for drilling a new one. So it is not economical to drill multiple shallower wells compared to a deeper one. Earnings of a wellbore targeting 6,000 m are four-times higher compared to wellbore targeting 4,000 m, whereas the costs for the construction of two 3,000 m subsurface located wells amount to 6.8 million EUR compared to one 5,000 m subsurface well of 6.3 million EUR. The pay-out time for a subsurface located 5,000 m geothermal well is 30.6 years, whereas 36.0 years are required for a 6,000 m surface located geothermal well. 15% of the annual earnings are assumed as OPEX for the operation of the well.

## Conclusion

The declared objective of the case study was to identify whether geothermal energy can be recovered from already existing subsurface facilities in a technically feasible, safe, and economical manner. Altogether, the results from the present study are promising for a successful implementation of a deep geothermal probe within a cavern, but with restrictions. The subsurface approach within a subsurface facility is economically feasible only if the cavern or tunnel already exists. A cavern constructed only for geothermal recovery will not financially justify the savings in 1,000 m of the wellbore. Possible synergies must be identified and utilized; only then will such a project will be financially feasible. Considerations must be made concerning the legal aspects. A drilling rig has never been in operation below ground; a legal framework must be worked out in advance. Emergency exit concepts from the rig site must be thoroughly elaborated.

## Declarations

# Availability of data and material

All data will be provided on request

# Competing interests

There are no competing interests

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The research has not been funded from the industry

# Authors' contributions

All authors have done the research together and equally distributed

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# Figures

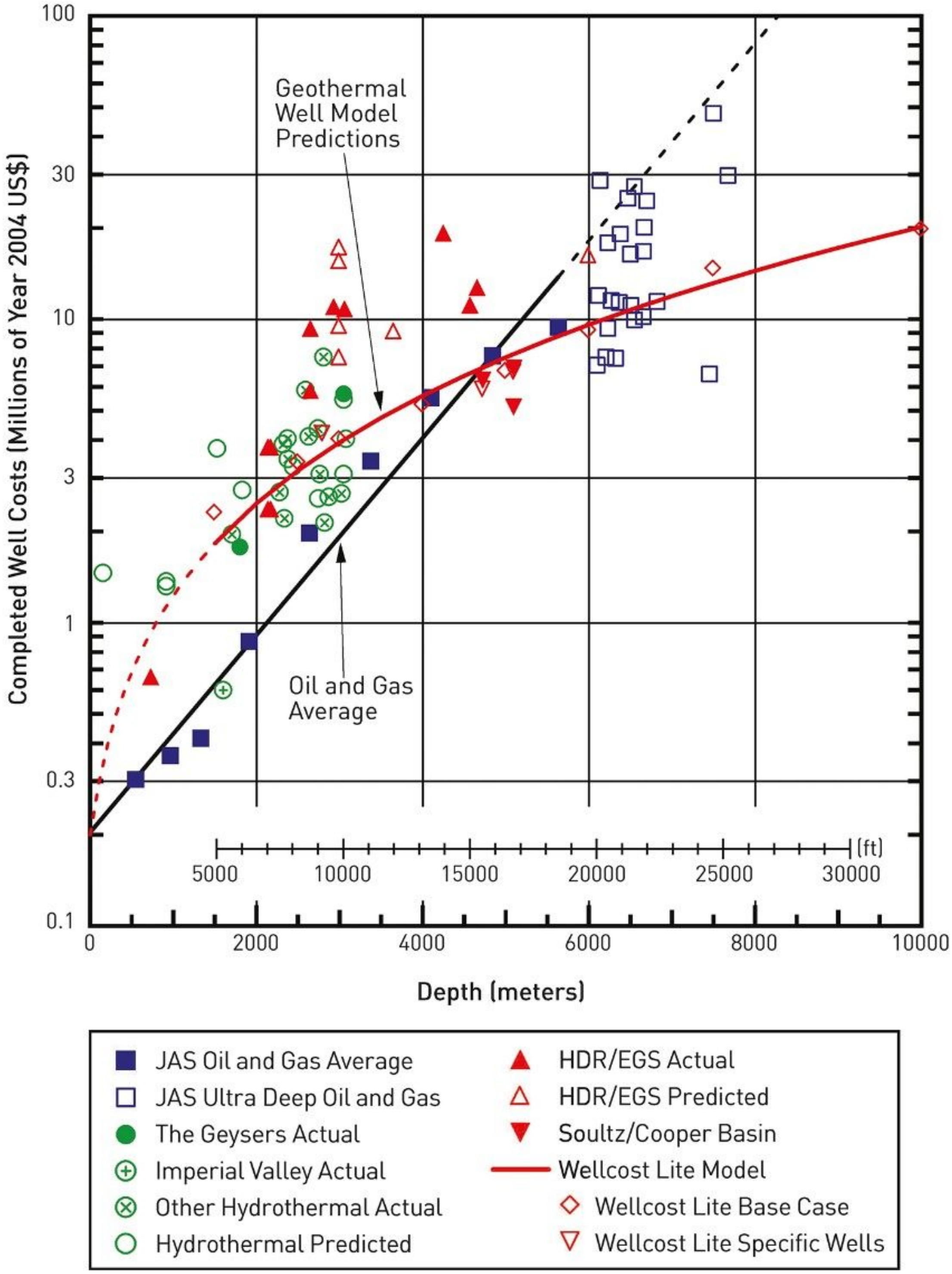



**Figure 1**

Figure 1

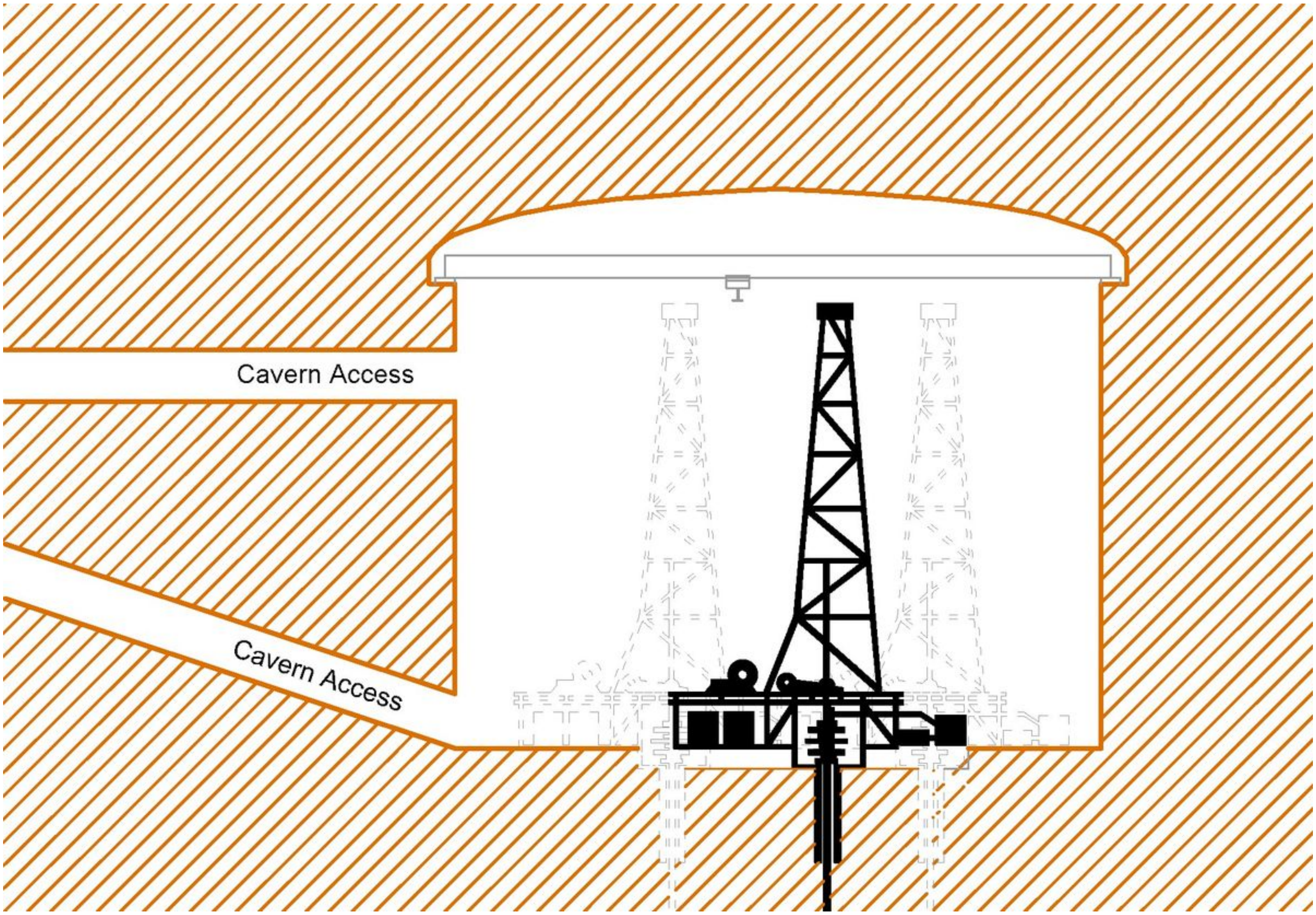
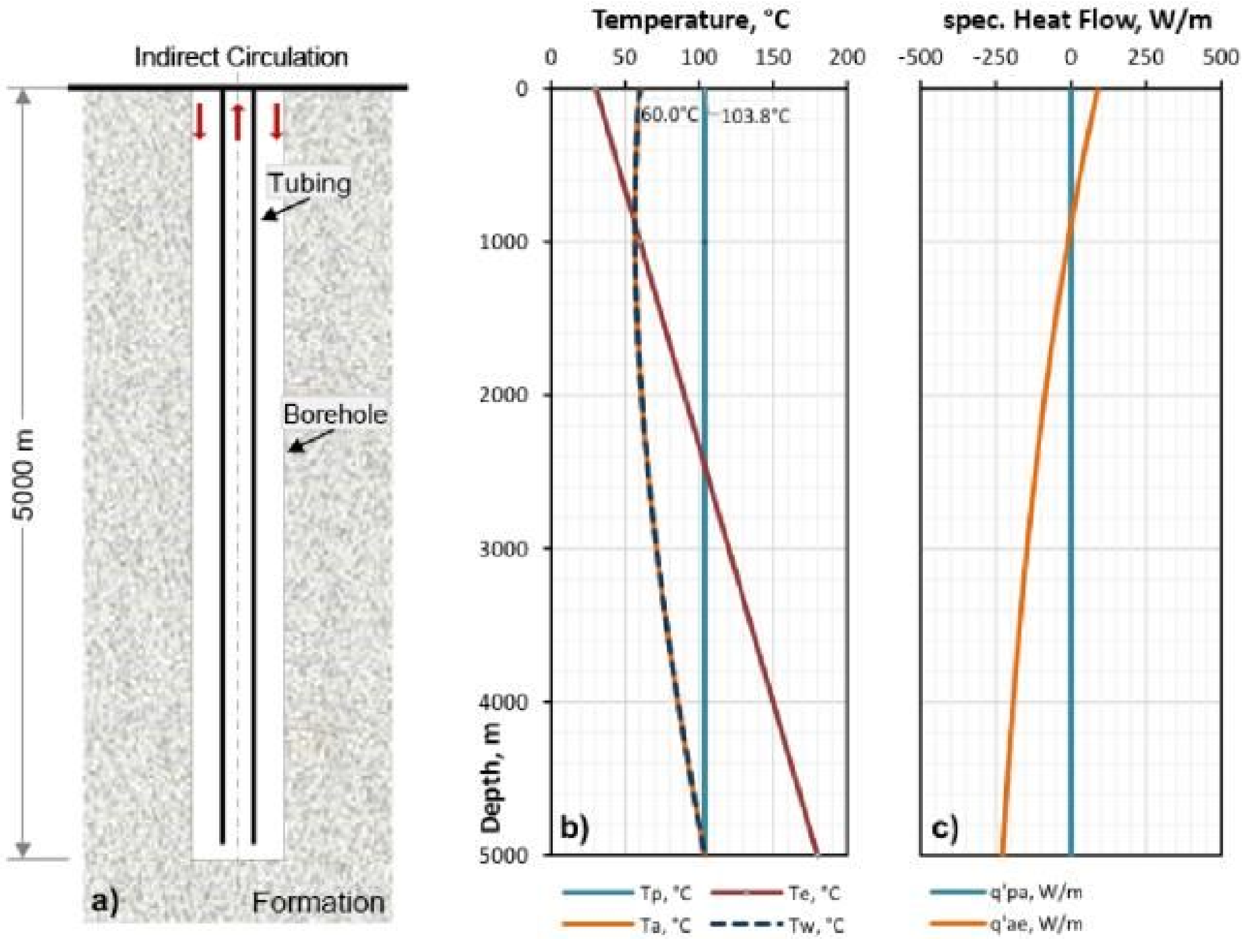



**Figure 2**

Figure 2




## Figure 3

Figure 3

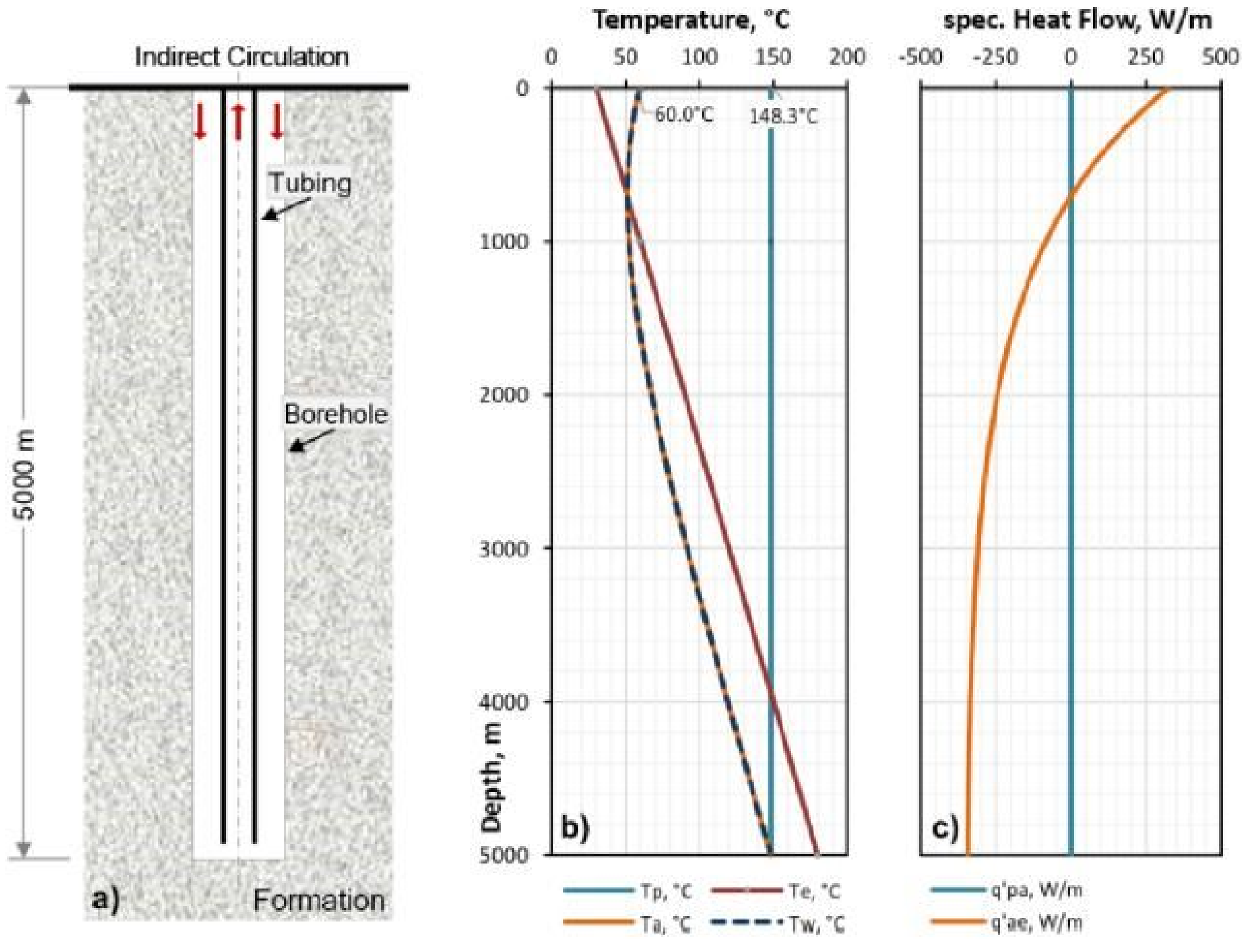
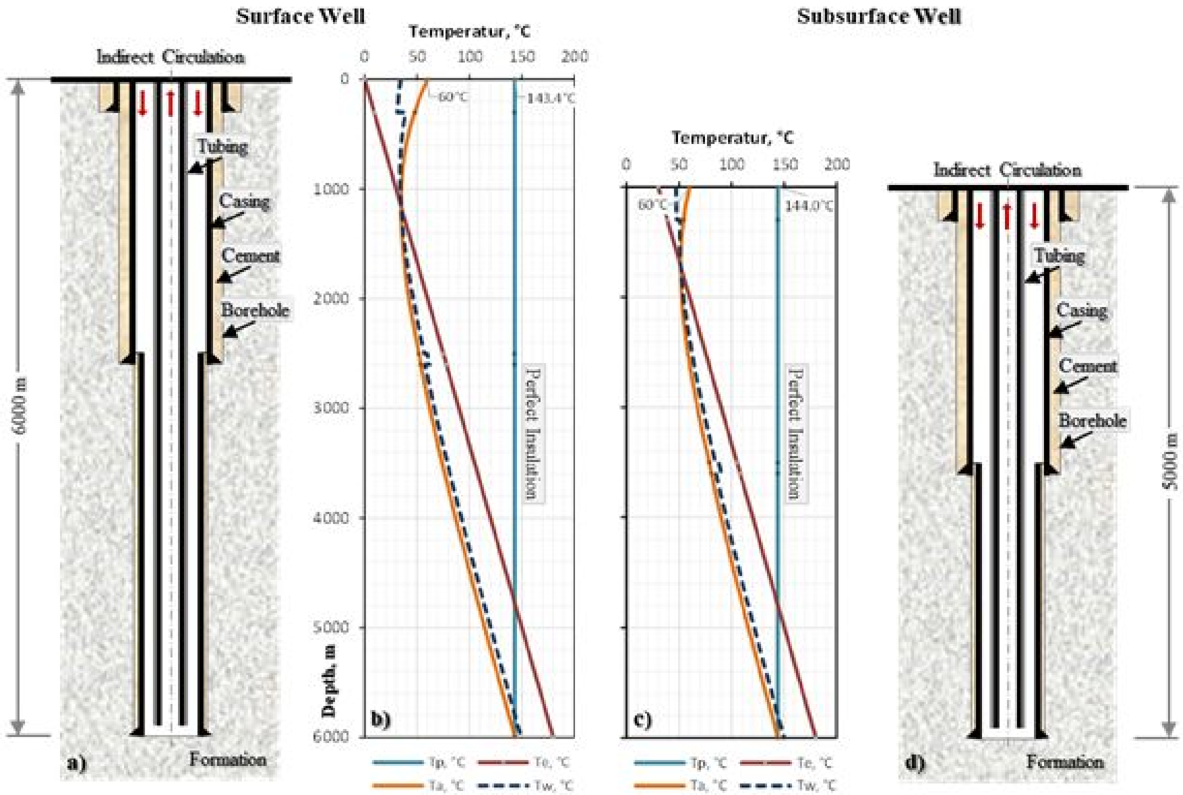



**Figure 4**

Figure 4




## Figure 5

Figure 5