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Analyzing Cost Drivers of Geothermal Heat Production for Sustainable Economic Solutions in District Heating Systems

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ABSTRACT

This study examines the cost structure of geothermal heat production for district heating in Switzerland, focusing on deep hydrothermal systems at depths between 1,000 and 2,500 meters. Using a techno-economic model, the analysis evaluates the impact of technical and financial parameters — including geothermal flow rate, production temperature, load factor, investment costs, and discount rate — on the levelized cost of heat (LCOH).

While deeper systems involve higher investment costs, they may result in lower LCOH due to higher production temperatures and reduced energy costs. The analysis also emphasizes the critical role of subsurface uncertainties, particularly reservoir characteristics that affect flow rate. Additional considerations include prospection costs and financial risks related to dry or underperforming wells, which are especially relevant in Switzerland's context of limited subsurface data. The findings offer key insights and practical recommendations to enhance the economic viability and strategic planning of geothermal district heating projects.

1. INTRODUCTION

Geothermal energy is a stable and low-emission resource with strong potential to support the decarbonization of heating systems. Unlike solar or wind, it provides a continuous supply of thermal energy, has minimal land use requirements, and integrates well into urban environments. In Switzerland, deep aquifers suitable for direct heat use are located between 500 and 3,000 meters underground (Chelle-Michou and al, 2017), with formation temperatures ranging from approximately 30°C to 100°C — well suited for district heating applications.

Despite this potential, deep hydrothermal geothermal energy remains underdeveloped in Switzerland, with only one operational district heating system in Riehen, near Basel. This is largely due to uncertainty about subsurface conditions and the financial risks associated with drilling. However, growing political and public support for renewable heat, along with national decarbonization goals, is driving renewed interest and investment in geothermal development.

This study aims to evaluate the levelized cost of geothermal heat production across a range of technical configurations and depths using the techno-economic model *GeoCAD*, developed by the University of Geneva (Faessler and Quiquerez, 2016). By analysing the most influential cost drivers and exploring the role of financial and operational parameters, the study seeks to provide a robust foundation for decision-making in future geothermal district heating projects.

2. METHODOLOGY: LEVELIZED COST OF HEAT (LCOH)

The levelized cost of heat (LCOH) is used to assess the average lifetime cost of heat generation, expressed in currency per unit of energy (e.g., CHF/kWh). It includes all costs incurred over the system's operational life — such as capital investment, operation and maintenance, energy consumption — and divides them by the total heat output over the same period.

LCOH is a standard metric in energy project evaluation and allows consistent comparison across different heating technologies (Aldersey-Williams and Rubert, 2019). It is calculated using the following general formula [1]:

$$LCOH = \frac{Total\ lifetime\ costs}{Total\ lifetime\ heat\ produced} = \frac{\sum_{t=1}^{n} \frac{I_t + M_t + F_t}{(1+r)^t}}{\sum_{t=1}^{n} \frac{Q_t}{(1+r)^t}} \quad [1]$$

The input values are:
I_t : Investment costs in time interval t
M_t : Operation and maintenance costs in time interval t
F_t : Energy costs in time interval t
Q_t : Heat generated in time interval t
r : Discount rate
n : Expected lifetime of the heating plant

This study focuses exclusively on the cost of geothermal heat production up to the point of delivery to the district heating interface. It excludes costs related to the heat distribution network, which depend heavily on factors such as linear heat density (i.e., heat demand per meter of pipeline) and urban layout (Nussbaumer and Thalmann, 2016). These network-specific costs are highly context-dependent and fall outside the scope of this analysis.

3. GEOTHERMAL PLANTS EVALUATED

This study evaluates geothermal plants with production and injection wells at depths of 500, 1,000, 1,500, 2,000, and 2,500 meters (see Figure 1). The depth of the wells influences both the production temperature and the associated investment costs.

At shallower depths, the lower temperature of the geothermal fluid requires the use of a heat pump. Additionally, shorter wells are usually vertical, which means that production and injection wells must be spaced apart, necessitating two separate well platforms and connecting pipelines.

At greater depths, higher temperatures often allow for direct heat use without the need for a heat pump. In such cases, deviated wells can be drilled from a single platform, potentially reducing surface infrastructure costs.

4. HEAT PRODUCTION ASSUMPTIONS AND PARAMETERS

This section outlines the key assumptions used to estimate heat production for different geothermal configurations evaluated in the study. These assumptions relate to the accessible geothermal flow rate, fluid temperature, system configuration, and utilization level (see Table 1).

One of the most critical factors is the geothermal flow rate, which directly determines how much heat can be extracted from the reservoir (Daniilidis and al, 2017). In Switzerland, the lack of deep drilling data makes it difficult to reliably estimate this parameter. Flow rate depends on subsurface properties such as:

- Permeability – the ability of fluid to flow through rock
- Porosity – the fraction of void space in the rock
- Transmissivity – a combined measure of permeability and aquifer thickness.

To maintain comparability across depths, a reference flow rate of 50 liters per second is used in all base-case scenarios. While this simplification does not reflect actual variation in geological productivity, its impact is explored in the sensitivity analysis.

Temperature assumptions are based on a geothermal gradient of 30 °C per 100 meters, with a surface temperature of 12 °C (Chelle-Michou and al, 2017). This leads to estimated production temperatures ranging from approximately 27 °C at 500 meters to 87 °C at 2,500 meters. Whether this heat can be used directly depends on the district heating return temperature, assumed to be 45 °C.

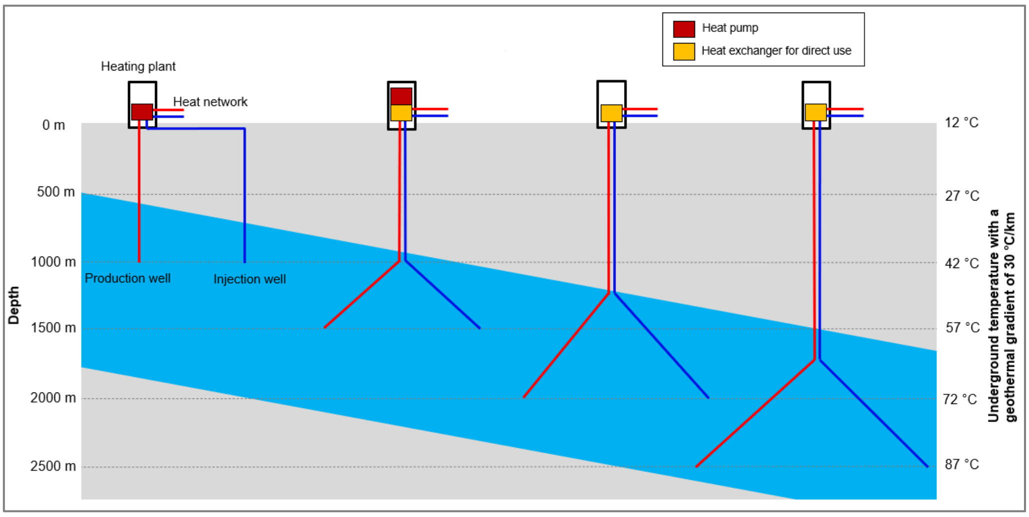

Figure 1: Geothermal heating plants considered in the analysis.

Table 1: Key technical assumptions for the base case scenarios.

Well depth	m	1000	1500	2000	2500
Geothermal production temperature	°C	42	57	72	87
Geothermal flow rate	l/s	50	50	50	50
Injection temperature	°C	25	35	45	45
Direct heat use capacity	MW	0	2.5	5.6	8.8
Heat pump capacity	MW	4.4	2.5	0	0
Total geothermal plant capacity	MW	4.4	5.0	5.6	8.8
Load factor	%	60%	60%	60%	60%
Heat production	GWh/y	23.0	26.5	29.7	46.1
Heat pump electricity consumption	GWh/y	4.3	2.3	0.0	0.0
Submersible pump electricity consumption	GWh/y	0.9	1.2	1.5	2.3

System configurations evaluated vary with depth:

- At 1,000 meters, heat pumps are required to meet the network temperature.
- At 1,500 meters, a hybrid configuration is assumed: part of the thermal energy is used directly, while the rest is extracted using a heat pump (Beyer and Racle, 2021).
- At 2,000 and 2,500 meters, direct heat use is feasible without heat pumps in the base case configuration. However, the addition of a heat pump on the return line could allow for further heat extraction, though this option is not considered in the present analysis.

Injection temperature is set at 45 °C for deeper systems and lower (25–35 °C) for shallower systems where heat pumps are used. These values are chosen to balance energy recovery with reservoir protection and technical constraints.

The thermal capacity of each system increases with depth, ranging from approximately 4.4 MW at 1,000 meters to 8.8 MW at 2,500 meters, assuming a constant flow rate.

The annual energy output depends on the system's load factor — that is, the proportion of the year the plant operates at full capacity. This, in turn, is influenced by the size of the connected heating network and the presence of complementary peak-load technologies.

Under typical Swiss conditions, a 100% geothermal-based district heating system would reach a maximum load factor of around 30% due to the seasonal nature of heat demand (Faessler et al., 2015). However, when geothermal energy is integrated into a larger district heating network and supported by additional peak-load technologies, the load factor can increase — even though the share of geothermal in the total heat supply mix may decrease.

As shown in Figure 2, achieving a 60% load factor with a 5.6 MW geothermal plant — the base case for a 2,000-meter system — would require a district heating network with an annual heat demand of approximately 33 GWh. Naturally, maintaining the same load factor for systems with greater geothermal capacity would necessitate proportionally larger heat networks.

5. ECONOMIC ASSUMPTIONS

5.1 Investment costs

Investment costs for geothermal heating plants are mainly influenced by well depth, drilling configuration (vertical or deviated), surface infrastructure requirements, and the use of heat pumps when needed. This analysis includes drilling and testing, interconnection between wells (if applicable), construction of the heating plant (buildings and technical systems), plus a 15% margin for engineering, contingencies, and other expenses.

Total investment costs range from 20 million CHF for a system with 1,000-meter wells to 29.1 million CHF for one at 2,500 meters (see Figure 3). The increase is primarily due to deeper drilling, which requires more time, heavier equipment, and more complex techniques — resulting in higher cost per meter. In contrast, 1,000-meter wells are drilled vertically using lighter rigs, which reduces drilling costs. However, production and injection wells at this depth must be spaced farther apart to avoid thermal interference, raising surface infrastructure costs.

Heat pumps are only needed at 1,000 and 1,500 meters, where temperatures are too low for direct heating. Their costs are included in the overall plant investment.

Overall, specific investment costs range from approximately 4.5 million CHF/MW at 1,000 meters to 3.3 million CHF/MW at 2,500 meters.

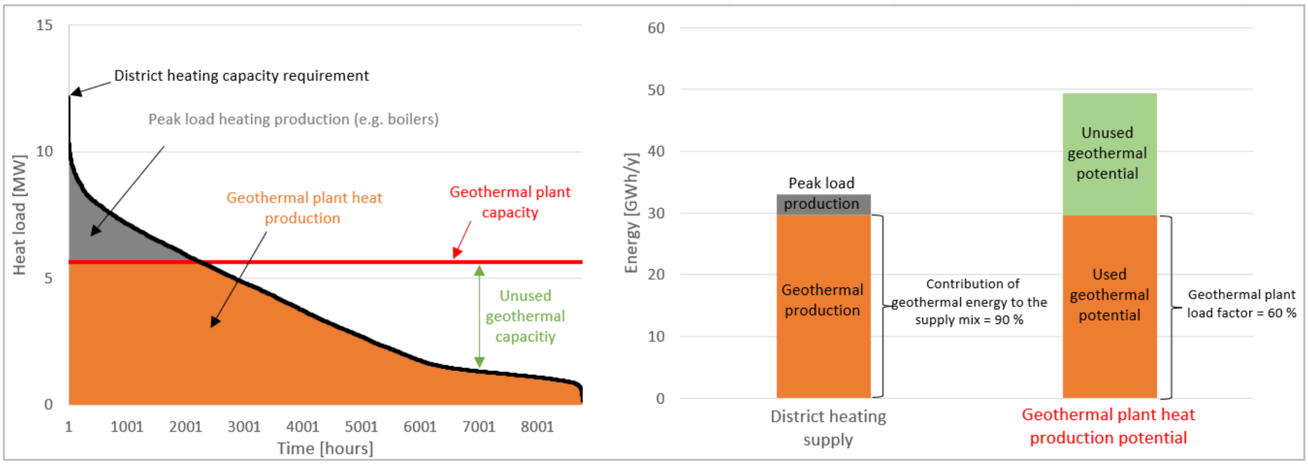

Figure 2: Illustration of a load duration curve for a geothermal district heating system (left) and corresponding annual energy (right). The example shows a 5.6 MW geothermal plant connected to a district heating network with an annual demand of 33 GWh.

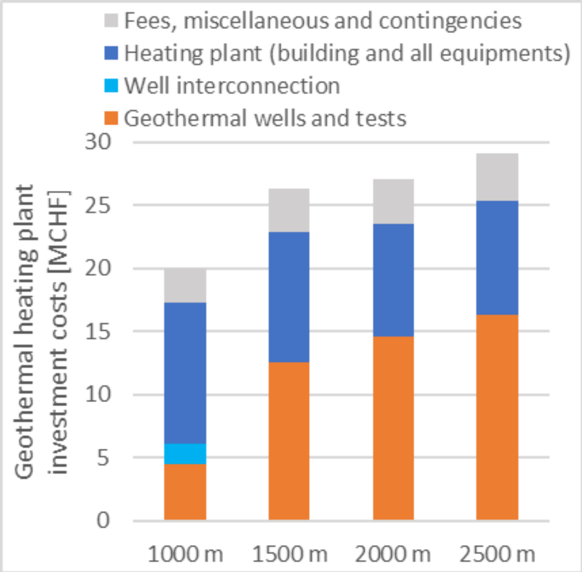

Figure 3: Investment costs for geothermal heating plants with doublets at various depths.

In calculating the levelized cost of heat (LCOH), a discount rate of 4% and a plant lifetime of 30 years are assumed.

It is important to note that prospection costs — such as seismic surveys and other geophysical studies used to determine drilling locations — are not included in the investment figure presented here. Similarly, no financial provisions have been made for the risks associated with dry or underperforming wells, despite these being significant concerns in areas with limited subsurface data. Both of these aspects are addressed separately in Section 7.

5.2 Operation, Maintenance, and Energy Costs

Beyond the initial capital investment, geothermal heat production entails ongoing operation and maintenance (O&M) expenses. These include the management and supervision of the facility, routine servicing of key components such as pumps and heat exchangers, continuous system monitoring, and occasional well maintenance or rehabilitation over the plant's operational lifetime.

In this study, O&M costs are estimated using a combination of fixed and variable components. The fixed portion is calculated at 1.5% of the total initial investment, while the variable component is set at 0.5 cts/kWh of heat produced. In the base case scenario — assuming a 60% load factor — this results in total O&M expenses equivalent to approximately 2% of the initial investment per year, a value consistent with industry benchmarks for geothermal infrastructure (Pratiwi and Trutnevyte, 2022).

Energy costs are also incorporated, primarily reflecting the electricity required to run circulation pumps and, where necessary, heat pumps. These costs are determined by multiplying the annual electricity consumption (as specified in Section 4) by an assumed electricity price of 22 cts/kWh in the base case.

6. RESULTS: LEVELIZED COST OF GEOTHERMAL HEAT PRODUCTION

6.1 Cost structure in the base case

The levelized cost of geothermal heat (LCOH) in the base case scenario — based on the assumptions detailed in Sections 5 and 6 — is presented in Figure 4. The LCOH ranges from 11.8 cts/kWh for a system with wells at 1,000 meters depth to 6.2 cts/kWh for a system drilled to 2,500 meters.

Although investment costs rise with depth due to more complex drilling and infrastructure requirements, the LCOH declines. At equivalent flow rate, the lower costs of deeper systems are mainly due to their higher thermal output and reduced reliance on heat pumps, which significantly cuts electricity consumption. Elevated production temperatures at greater depths enable direct heat use, improving system efficiency and reducing energy-related operating costs.

Overall, geothermal heat production is characterized by a high share of fixed capital costs relative to variable operational expenses. In comparison to other heat generation technologies, geothermal systems are capital-intensive but benefit from low ongoing costs. This structure places strong emphasis on maximizing the annual utilization of the system. As a result, the load factor becomes a key determinant of economic performance: higher utilization rates spread fixed costs over more kilowatt-hours, lowering the LCOH. This relationship is further examined in the next section.

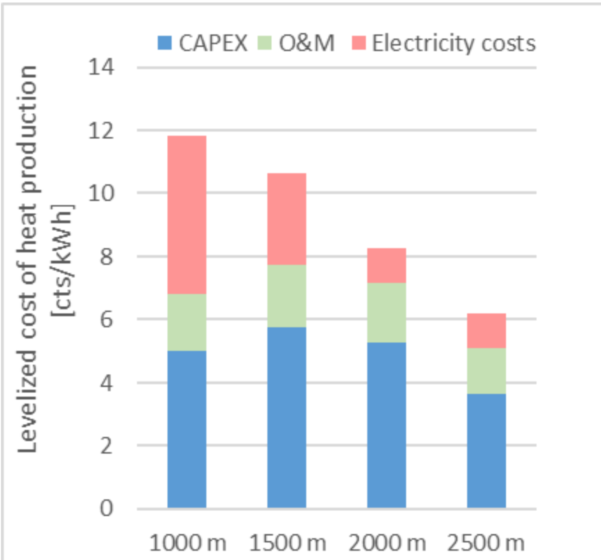

Figure 4: Levelized cost of heat (LCOH) for geothermal heating plants with doublets at various depths.

6.2 Sensitivity analysis on key parameters

A sensitivity analysis was conducted to evaluate how different parameters affect the LCOH. The results for systems with wells at 1,000 meters and 2,000 meters depths are presented in Figures 5 and 6, respectively.

The sensitivity analysis reveals the following key parameters with the greatest impact on LCOH:

- **Geothermal Flow Rate**: This is the most influential factor. The flow rate is highly uncertain, especially in regions with limited hydrogeological data. It is influenced by subsurface characteristics, such as permeability and porosity, which are difficult to estimate during early project stages.
- **Injection Temperature**: The injection temperature is primarily determined by the return temperature of the district heating network. However, minimum thresholds must be met to prevent thermal and mechanical stress on both the reservoir and the infrastructure, ensuring long-term system stability.
- **Load Factor**: This parameter represents how much the geothermal system is utilized throughout the year. It depends on the size and configuration of the district heating network, and whether additional heat sources are available to meet peak demand.
- **Discount Rate**: The discount rate is a financial factor that directly impacts the present value of future costs. A higher discount rate increases the LCOH, underlining the importance of favourable financing conditions for the economic feasibility of geothermal projects.

A significant difference between the 1,000-meter and 2,500-meter systems is their sensitivity to electricity prices. The shallower system relies on a heat pump to reach usable temperatures and is therefore more sensitive to electricity price fluctuations. In contrast, the deeper system provides direct-use heat and is largely unaffected by electricity costs.

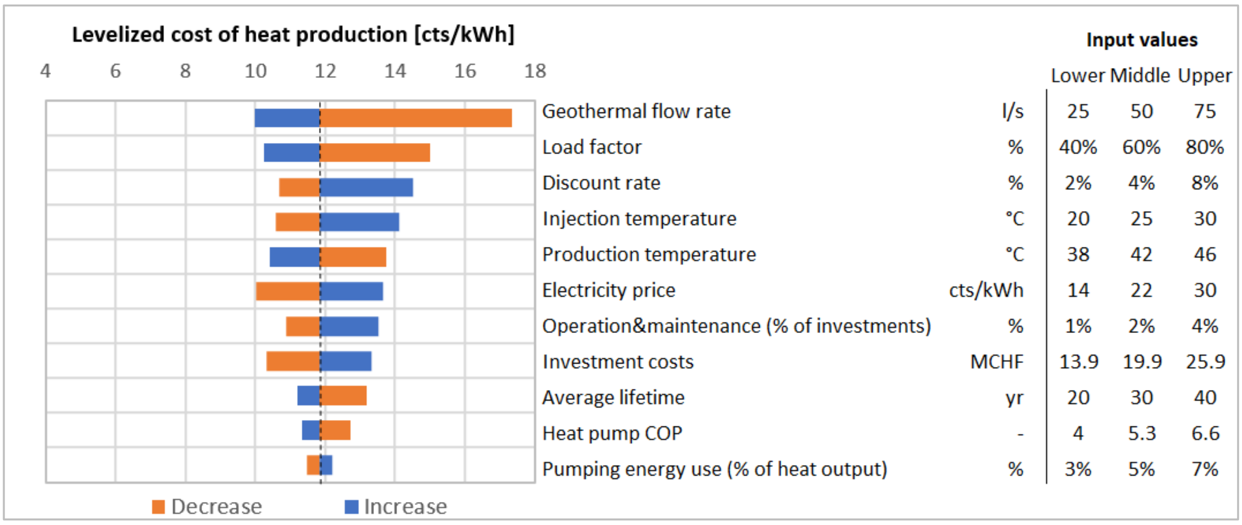

Figure 5: Sensitivity analysis of the LCOH for a geothermal heating plant with a doublet at 1,000 meters depth. The LCOH is shown on the left, with the corresponding input parameter ranges displayed on the right.

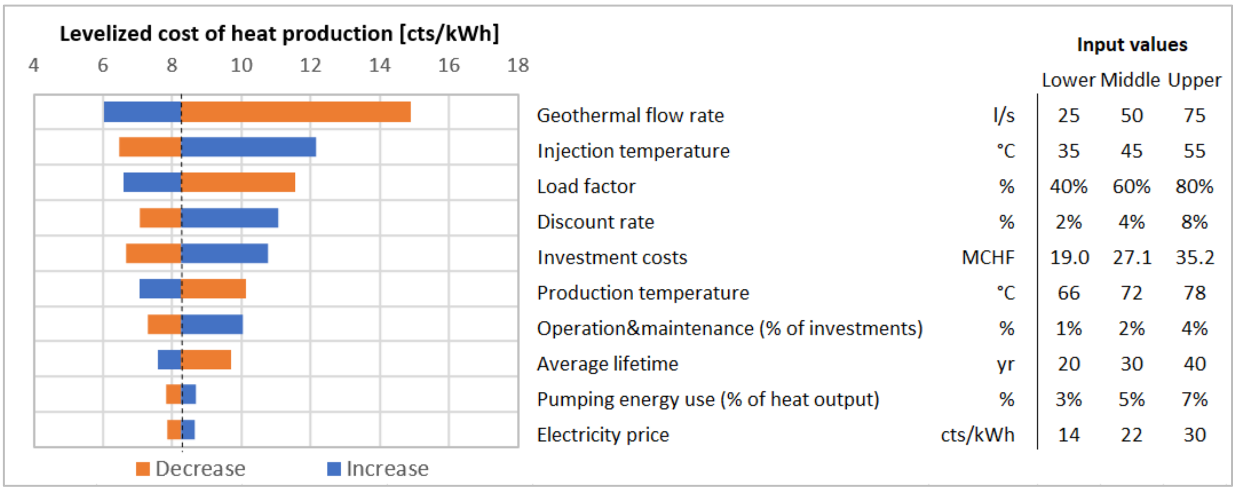

Figure 6: Sensitivity analysis of the LCOH for a geothermal heating plant with a doublet at 2,000 meters depth. The LCOH is shown on the left, with the corresponding input parameter ranges displayed on the right.

Figures 7 and 8 further illustrate how geothermal flow rate and load factor influence LCOH. To maintain LCOH below 10 cts/kWh, minimum flow rates are approximately 25 l/s at 2,500 meters, 28 l/s at 2,000 meters, 50 l/s at 1,500 meters, and 75 l/s at 1,000 meters. These values emphasize the critical importance of reservoir productivity. Notably, a 1,000-meter system with high flow can achieve a lower LCOH than a 2,500-meter system with lower flow, despite the deeper system accessing hotter resources. This highlights that optimizing flow rate is key — greater depth alone does not guarantee lower costs.

With respect to the load factor, the analysis shows that when utilization falls below 30%, the LCOH rises sharply, making the project economically unviable. This is primarily due to the dominance of fixed costs in geothermal systems. Conversely, higher load factors substantially reduce the cost per kilowatt-hour by distributing these fixed expenses across greater annual heat output, underlining the importance of maximizing system utilization for economic efficiency.

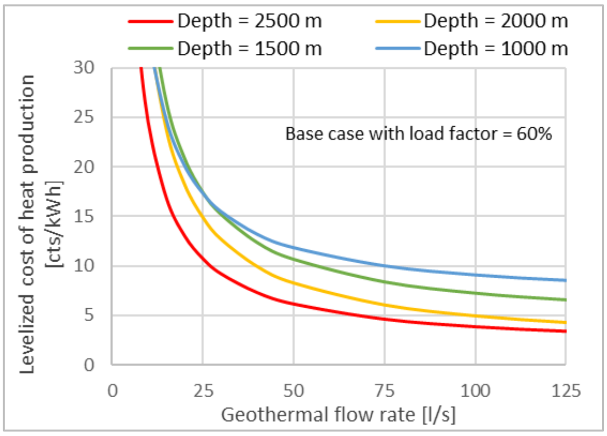

Figure 7: Impact of flow rate on the levelized cost of heat for geothermal heating systems with doublets at varying depths.

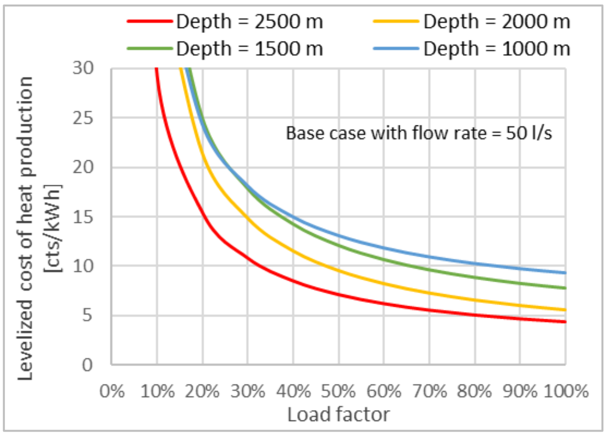

Figure 8: Impact of load factor on the levelized cost of heat for geothermal heating systems with doublets at varying depths.

7. ADDITIONAL COST CONSIDERATIONS

As discussed earlier, the cost analysis in the previous section did not consider certain additional costs, such as prospection costs and the costs associated with potential dry wells. These additional costs, while sometimes overlooked, are crucial for accurately estimating the total cost of geothermal heat production. In some cases, these costs are integrated into the project's business plan and, consequently, reflected in the heat price, meaning that the final users of the geothermal system ultimately bear the cost. In others, these costs may be covered by the community, through public funding mechanisms such as subsidies or risk guarantee schemes designed to improve the economic viability of geothermal projects.

7.1 Subsurface prospection costs

Before drilling production wells, preliminary studies are typically required to assess the geothermal potential of a region. The cost of these studies varies significantly depending on the availability of existing data, the scale of the area under investigation, and the technologies used. For example, a comprehensive 3D seismic survey to map geothermal potential across a large urban area can cost several million CHF. In contrast, simpler 2D seismic surveys — less detailed and covering smaller areas — are generally much more affordable.

Prospection costs can represent a significant share of the upfront investment and should be carefully factored into project economics. These costs can be integrated in the levelized cost of heat (LCOH), directly affecting the financial feasibility of a geothermal project. Table 2 presents the annualized prospection costs over the plant's lifetime, expressed in cts/kWh, as a function of initial prospection costs and expected geothermal heat output.

Table 2: Annualized prospection costs over the plant lifetime, expressed in cts/kWh, depending on initial prospection costs, and expected geothermal heat output.

		Initial prospection costs in MCHF				
		0.5	1	5	20	50
Expected geothermal heat output in GWh/y	20	*0.1*	*0.3*	*1.4*	*5.8*	*14.5*
	50	*0.1*	*0.1*	*0.6*	*2.3*	*5.8*
	100	*0.0*	*0.1*	*0.3*	*1.2*	*2.9*
	500	*0.0*	*0.0*	*0.1*	*0.2*	*0.6*

The relationship between prospection costs and expected geothermal output — closely tied to the potential scale of district heating deployment — is a key factor for developers. When prospection costs are high relative to anticipated production, the resulting heat cost may become economically unsustainable. Ensuring that prospection efforts align with realistic output expectations is therefore essential for project feasibility.

Table 3: Annualized cost impact of dry wells on geothermal heat, based on different probabilities of success for a 2,000-meter geothermal plant. Success is defined as one doublet producing 30 GWh/year.

Probability of success		**80%** 1 dry well for 4 successful doublets	**75%** 1 dry well for 3 successful doublets	**66%** 1 dry well for 2 successful doublets	**50%** 1 dry well for 1 successful doublet	**33%** 2 dry wells for 1 successful doublet
Costs of dry well per successful doublets	MCHF	2.2	2.9	4.5	8.8	17.5
Annualized costs of dry well per kWh produced by successful doublets over plant lifetime	cts/kWh	*0.4*	*0.6*	*0.9*	*1.7*	*3.4*

7.2 Accounting for the financial risk of dry wells

Geothermal projects face the risk of drilling dry wells — wells that do not yield sufficient or usable geothermal heat. This risk represents a major uncertainty in project planning and financing, as the associated costs must still be covered even when no heat is produced. The financial impact of dry wells can be estimated using success probabilities, which reflect the likelihood of drilling a productive well (Schumacher et al., 2020).

For developers managing multiple projects, this risk can be distributed across their portfolio. By pooling the outcomes of several drilling operations, the financial burden of an unsuccessful well is shared, reducing the impact on the overall cost structure of individual projects.

Table 3 illustrates how the levelized cost of heat increases under different probabilities of success. For instance, with an 80% success rate — equivalent to one dry well for every four successful doublets — the additional cost is around 0.4 cts/kWh. However, as the probability of success decreases, the added cost rises substantially. These findings highlight the importance of incorporating geological risk into early-stage project assessments and financial planning.

8. CONCLUSIONS

This study provides a comprehensive analysis of the levelized cost of geothermal heat for deep hydrothermal systems in district heating networks in Switzerland. The results underscore the importance of both technical and financial factors in determining the economic feasibility of geothermal projects. Key findings show that although deep wells require high initial investments, geothermal heating plants can deliver highly competitive heat costs — primarily due to their energy efficiency and the resulting low operational and energy expenses.

Sensitivity analyses indicate that geothermal flow rate, injection temperature, and load factor are the primary technical cost drivers. These parameters are strongly influenced by subsurface conditions as well as the design and utilization of the heating network. On the financial side, the discount rate has a substantial impact on overall costs, highlighting the importance of access to favourable financing terms and stable policy support for project bankability. As such, cost efficiency is inherently site-specific, shaped by both the underlying geological conditions and the effectiveness of integration into the local district heating infrastructure.

The analysis also emphasizes two significant but often underappreciated cost elements: initial geological prospection and the risk of dry or underperforming wells. In Switzerland — where deep subsurface data remains limited — these uncertainties introduce significant financial risk and must be rigorously addressed during early planning and investment decisions.

To establish geothermal heat as a reliable and competitive component of Switzerland’s sustainable heating transition, three priorities are essential: (1) improving geological knowledge through targeted prospection and open data sharing; (2) enhancing system integration within efficient district heating networks; and (3) mitigating financial risk through public policy instruments such as guarantees, subsidies, or portfolio-based development models. Addressing these technical and financial challenges in a coordinated manner will be key to scaling geothermal deployment and realizing its full potential as a low-carbon, base-load heat source for district heating.

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