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Portability of Deep Geothermal Closed Coaxial Wells

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ABSTRACT

The HOCLOOP EU project ("A circular by design environmentally friendly geothermal energy solution based on a HOrizontal Closed LOOP") aims to verify a novel geothermal closed loop solution for the extraction of heat from deep formation rocks. To pave the way for future demonstration projects and to assess the forward portability of the HOCLOOP solution, in-depth simulations of the under-ground system (borehole and rocks) and the above-surface energy systems are carried out for a wide variety of geothermal cases ranging from green field exploration site to fully functional geothermal plants including district heating. In this framework, the project covers the investigation of potential EU pilot sites in Belgium, France, Italy, Germany and Poland. Each geothermal site presents different geological environment (heat flux, lithology, etc.) that eventually defines the borehole design (depth, horizontal length, etc.) and the selection of the surface equipment (heat pump, heat exchanger, turbine, etc.). In this work, the different cases (excluding Germany) are compared and the advantages. in relation to the geological setting and the energy objective (heat or electricity production) are presented. Based on the findings, a discussion is made on how the solution could be deployed at the various locations.

1 INTRODUCTION

The HOCLOOP project introduces an innovative horizontal closed-loop approach to geothermal energy extraction, tackling key challenges in sustainable heat production across Europe. This paper presents techno-economic feasibility assessments for five pilot sites, based on integrated designs combining underground loops and surface systems. Energy flow simulations generate key performance indicators for multi-criteria evaluation, leading to detailed pre-designs with preliminary P&IDs and CAPEX/OPEX estimates. The study assesses economic viability, integration with district heating, and market conditions such as carbon pricing and renewable incentives. Overall, HOCLOOP aims to deliver a scalable, sustainable geothermal solution supporting Europe's decarbonization goals.

2 METHODOLOGY

The techno-economic feasibility assessment combines technical simulations and economic modelling to evaluate HOCLOOP deployment at each pilot site through four integrated components. Technical Design and Integration develops conceptual designs based on site geology, infrastructure, and demand, optimizing well trajectories, equipment sizing, and district heating integration. Energy System Modelling uses validated tools developed by each partner (GTW from IFE, GWellFM from IFPEN, BHEModel2.0 from UNIFI) to simulate performance, optimize flow, temperature, and pressure parameters, and compare HOCLOOP with conventional systems over 20–30 years. Economic Analysis applies standard cost-estimation methods, covering drilling, equipment, and installation, with site-dependent financial details ranging from full LCOE models to basic cost estimations. Multi-criteria Assessment evaluates technical, economic, and integration performance, including sensitivity analyses on energy prices, carbon costs, and subsidies to test system robustness.

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† Deceased 31 July 2025

3 OVERVIEW OF THE CASE STUDIES

The HOCLOOP project explores a novel horizontal closed-loop geothermal system designed to deliver sustainable, low-emission heating solutions adaptable to diverse geological settings. Six pilot sites across Europe, in France, Belgium, Italy, Germany and Poland, were selected to test the concept under different geological, climatic, and infrastructural conditions. Each site represents a distinct combination of subsurface characteristics, heat-demand profiles, and integration strategies.

3.1 France (Fresnes, near Paris)

The French pilot site is located south of Paris, close to Orly airport, within an existing urban district-heating network (DHN) supplied by a geothermal doublet tapping the Dogger formation. The study focuses on repurposing an existing injection well (GFR-3) to host a horizontal closed loop. The concept aims to demonstrate how HOCLOOP could operate alongside, or as an alternative to, conventional doublets in a mature geothermal field. The configuration includes a 500 m deepening and a 2 km horizontal extension of the well, connected to surface heat-exchange equipment and pumps.

3.2 Belgium (Mol – Balmatt site)

The Belgian case is based at the Balmatt geothermal research site operated by VITO in Mol. The site includes three existing deep wells, one of which (MOL-GT-03) is unproductive and identified as a potential test well for HOCLOOP integration. The concept involves using this well to supply heating to new VITO office and laboratory buildings via a short district-heating loop. The system design includes insulated underground or above-ground pipelines (≈ 834 m) and separate heat exchangers in each building to decouple the circuits.

3.3 Italy (Gavorrano and Amiata)

Two Italian sites were studied, both in Tuscany but representing different applications. First, Gavorrano, where a district-heating network serving small towns powered by several HOCLOOP wells designed to deliver heat between 80–40 °C has been considered. Second, Amiata, with a configuration coupling HOCLOOP wells with an Organic Rankine Cycle (ORC) unit to provide both electricity and process heat to agricultural greenhouses. The Amiata site represents a cogeneration application with multiple wells connected to an existing heat-use infrastructure. Both sites explore how HOCLOOP could be scaled to industrial or municipal heating systems.

3.4 Poland (Goleniów)

The Polish pilot focuses on the integration of HOCLOOP systems into an existing coal- and biomass-fired district-heating network in the city of Goleniów. The area features favorable salt-dome geological structures, offering high thermal conductivity and stable formations for long horizontal boreholes. The district heating system in Goleniów was designed and built as a second-generation DHN with a design temperature of 135/70°C. The base energy source is hard coal supplemented by biomass. The total installed power is 29.26 MW, including 6 MW biomass. Energy production is ~202 TJ/yr. The airport in Goleniów is heated by natural gas from a local heating station. The estimated power demand is 460 kW, and the energy consumption is 3.6 TJ/yr.

3.5 Germany (Darmstadt)

At the Campus Lichtwiese of TU Darmstadt, a high-temperature medium-depth borehole thermal energy storage (MD-BTES) system is currently under investigation. Due to the low geothermal gradient and unfavorable geological conditions at the site, the HOCLOOP concept is not considered suitable for this location. The boreholes are equipped with coaxial pipes, featuring polypropylene (PPR) inner liners. One of the key innovations of HOCLOOP technology is its dual-pipe configuration with a vacuum-insulated inner casing. This technology is also being examined for potential applications at the Darmstadt site; however, the results of that investigation are not presented in this paper.

4 RESULTS

4.1 French case study

4.1.1 Integration scenario

In the Fresnes site a geothermal plant extracts hot water from the Dogger reservoir at 73 °C and 250 m^3/h (≈70 kg/s) to supply a district heating network. The fluid is reinjected between 41 °C and 35 °C, or down to 25 °C when a heat pump operates at outside temperatures below 8 °C. Depending on reinjection temperature, the plant produces 9–14 MW of thermal energy, supplemented by cogeneration and emergency turbines. In 2016, the system delivered 51 GWh from geothermal, serving a 13 km network with 104 delivery points and 90 substations.

The study examines the possibility of extending an existing well 500 m deeper into the reservoir to reach higher temperatures, adding a 2 km horizontal section, and connecting it to the existing district heating network.

4.1.2 Simulation approach

A surface installation model was integrated into the GWellFM well flow model (Leontidis, Hernandez, Pogacnik, Wangen, & Harcouët-Menou, 2025) to estimate the net energy production. The first, which comprised connecting pipes, a heat exchanger and a pump, was replicated in COCO, a CAPE-OPEN steady-state simulation environment. Flowsheet modelling was conducted in COFE v3.8 and the equipment properties were computed through Python Unit Operation (PUO) scripts, which perform detailed thermodynamic calculations using fluid input conditions and parameters to determine output properties. The well model, on the other hand, calculates the temporal evolution of temperature and pressure along a deep coaxial closed well.

The surface model calculates: (i) the pressure losses and either the required heat exchanger surface area based on specified thermal performance targets or the optimal flow rates for cold fluid circuit for constant flow rate of the hot circuit in a counter-current plate exchanger, (ii) the pressure losses in the surface piping system, and (iii) the outlet conditions and the energy consumption of a pump for reinjecting the fluid in the well to compensate for the pressure losses both in the surface installation and the well. In the coupled simulations and at every time step, the well model provides to the surface model the pressure and temperature of the fluid at the outlet of the well and recovers the corresponding parameters at the exit of the injection pump.

Initially, coupled simulations were conducted to estimate the required heat exchange surface, with the results showing that, under constant flow rate, the well outlet temperature declines over time due to transient rock-to-fluid heat transfer (Figure 1). An inverse relationship between mass flow rate and outlet temperature was confirmed, as lower flow rates allow longer residence times and improved heat transfer. The analysis reveals a critical operational threshold: well exploitation must be terminated when the outlet temperature drops below 70°C. This temperature limit is imposed by the thermal cross-over phenomenon with the secondary fluid circuit, which operates at an outlet temperature of precisely 70°C. Below this threshold, the temperature difference becomes insufficient to maintain effective heat transfer across the heat exchanger, rendering the geothermal system thermodynamically inefficient and economically unviable.

Thermal power exhibits a continuous decline over the exploitation period due to reservoir thermal depletion. The relationship between flow rate and thermal power recovery shows a clear trade-off: higher flow rates yield greater initial output but cause faster reservoir cooling and sharper declines. Lower flow rates, in contrast, sustain more stable long-term heat production.

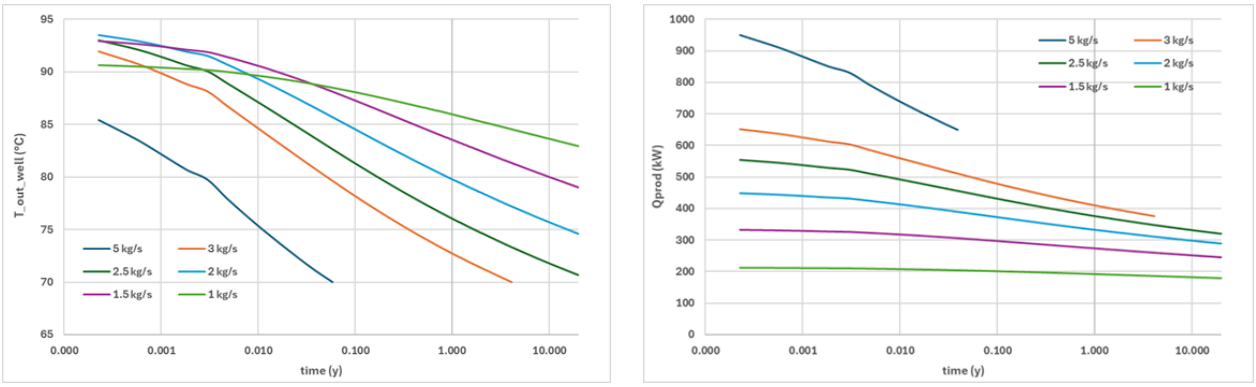


Figure 1. Evolution of outlet geothermal fluid temperature (left) and thermal power recovery (right) for non-constant heat exchanger surface area (Paris case).

Surface area requirements increase exponentially with operating time and flow rate, as declining reservoir temperatures demand larger heat exchanger surfaces to maintain performance. A 2 kg/s flow rate is selected, yielding a 75 °C well outlet and a 5 °C temperature difference with the 70 °C secondary loop, an economic optimum balancing heat recovery and exchanger size. This temperature gap ensures efficient heat transfer without the excessive costs of oversized equipment, maintaining long-term operational efficiency.

The analysis also reveals that at lower flow rates, the well outlet pressure exceeds the injection pressure (10 bar) due to the thermosiphon effect, where natural circulation is generated by the density differential between the heated ascending fluid and the cooler descending fluid. Over time, this outlet pressure exhibits a gradual decline, which correlates directly with the decreasing outlet temperatures that reduce the fluid density

differential and consequently diminish the thermosiphon driving force. At higher flow rates, friction losses within the wellbore surpass the pressure recovery provided by the thermosiphon effect, causing outlet pressures to drop below the injection threshold. Under these conditions, natural circulation becomes inadequate, and a mechanical pump is required to offset pressure losses and sustain flow in the geothermal loop. In this case study, pumping is only needed for flow rates above 3 kg/s. However, for practical operational considerations, particularly during system startup procedures, a centrifugal pump, with a flow rate of 7.26 m^3/h and a shaft brake power of 4.8 kW, was considered and included within the scope of the techno-economic evaluation.

Surface areas between 25 and 45 m^2 were tested at a constant flow rate of 2 kg/s to assess their effect on outlet temperature and thermal power output. Results showed minimal variation across this range, indicating that performance is not constrained by heat transfer area but by other factors. The nearly identical outlet temperature and thermal power trends confirm that reservoir thermal depletion, rather than heat exchanger limitations, governs system performance. By integrating the recovered thermal power over the respective time intervals, the total energy extracted throughout the well's operational lifetime could be determined and the average thermal power extraction rate could be calculated by dividing the cumulative energy by the exploitation duration. Increasing the heat exchanger area from 25 to 45 m^2 led to only a slight rise in total extracted net energy (27.63–28.26 GWh) and average thermal power (315–323 kW), indicating minimal sensitivity within this range.

4.1.3 Cost analysis

The cost estimation starts with evaluating equipment and utility costs, based on equipment size and utility needs defined. In this study, only the pump and plate heat exchanger are considered. Equipment costs are estimated using an internal IFPEN tool, which calculates costs for equipment, installation, and instrumentation. Although electricity is a potential utility, it is excluded here since the thermosiphon effect provides sufficient circulation, eliminating the need for mechanical pumping and associated energy consumption.

The case considers extending the existing well by 500 m deeper into the reservoir, followed by a 2 km horizontal section. Since the lower open hole formation is permeable, a 7” liner must be installed in the lower section of the well before installing the completion tubing. The total installation costs for a suitable DHS are estimated at 7 M€ (1 M€ mobilization, 2 M€ well operation, 4 M€ equipment and consumables). The well is assumed to have easy access for the well intervention. The cost for the removal of any existing completion string in the well prior to the operation is not included nor the costs associated with the connection of the well to the surface heat system. The operation is judged possible using a medium size drilling rig. No special drilling issues are reported.

The financial analysis determines the heat cost by evaluating equipment, utility, and drilling expenses within a defined financial context using IFPEN’s tool, which calculates project CAPEX, OPEX, and Net Present Value for various scenarios, with economic parameters such as tax rate, inflation rate, cost of debt and others. Outside Battery Limits (OSBL) costs, covering infrastructure, engineering, and contingencies, are expressed as percentages of the Inside Battery Limits (ISBL) costs, with respective values of 5 %, 10 %, and 15 %.

Direct and indirect installed costs make up the total installed costs (CAPEX). Direct costs are taken as 5% of the ISBL for the spare parts, whereas indirect costs (licensing, training, legal, start-up) represent 10% of the ISBL costs. Labor costs and fixed charges (maintenance, insurance and overheads) constitute fixed costs (OPEX). Labor, maintenance, insurance and overhead costs represent 1%, 1.5%, 0.5% and 1% of the ISBL costs, respectively. As the heat exchanger surface increases from 25 m^2 to 45 m^2, the average thermal power extraction rate rises slightly from 301.7 kW to 308.9 kW. Correspondingly, the heat exchanger cost grows from 164 k€ to 180 k€, while the pump cost remains constant at €126 k. Including design allowances, the total ISBL cost ranges from 319 k€ to 337 k€, resulting in a cost of energy decreasing marginally from 386.9 €/MWh to 379.3 €/MWh, reflecting small efficiency gains with increasing exchanger size.

4.1.4 Discussion

The optimal energy cost is achieved with a heat exchanger surface area of 40 m^2 and a geothermal fluid circulation rate of 2 kg/s, yielding an energy cost of 378.9 €/MWh. This cost remains significantly elevated compared to conventional energy sources, which typically range from 50-150 €/MWh. This economic disadvantage stems from the limited energy recovery relative to the substantial capital investment required for well installation and equipment. The well drilling and installation costs amount to 7000 k€, while equipment costs total 333 k€, resulting in a well-to-equipment cost ratio of approximately 21:1. This disproportionate capital structure highlights that the primary economic constraint lies in the high upfront investment for well development rather than surface equipment costs.

The project lifetime consideration deserves particular attention in the economic analysis presented. While the initial energy cost calculation of 378.9 €/MWh assumes a 20-year amortization period, this assumption warrants re-examination given the specific characteristics and advantages of closed-loop geothermal installations. These systems inherently benefit from exceptionally long operational lifespans with minimal degradation over time, which justifies exploring different temporal horizons for the economic assessment. In addition, the thermal output of the well is expected to deteriorate slowly, after the initial fast decrease of outlet temperature.

Sensitivity analysis across various project lifetimes reveals a significant decrease in energy costs as the amortization period extends. Indeed, the LCOE is estimated at 565, 329 and 293 €/MWh assuming project lifetime of 10, 30 and 50 years, respectively.

4.2 Belgium case study

4.2.1 Integration scenario

The well MOL-GT-03, currently used for research and monitoring, is proposed as the heat source. The scenario investigated explores using this well to heat new office buildings, with an injection temperature of about 40 °C. Simulations indicate the well could fully meet the buildings' heating demand for over 20 years and that although demand is seasonal, the well can handle 12-hour peaks above 600 kW.

While the current buildings design foresees an ATES system with a heat pump and chillers, the analysed case study evaluates supplying heat through the HOCLOOP concept. In such a case, heat transport from the well to the new buildings requires a district heating network approximately 834 m long, analysed in two configurations, aboveground and underground, respectively. To separate the building heating circuit from the HOCLOOP and district network circuits, a heat exchanger is installed in each building, while no exchanger is placed between HOCLOOP and the district network to minimize CAPEX and preserve temperature levels.

Integrating the HOCLOOP concept to meet the heating demand of the new VITO buildings requires additional surface infrastructure, including insulated piping between the well and the buildings. In addition, cooling, currently foreseen delivered by the ATES system, would need a separate system, ideally an air–water heat pump with heat recuperation, operating independently from the heating network. Consequently, separate piping systems are required for heating and cooling, with a heat exchanger in each building to transfer heat from the well to the internal circuits.

4.2.2 Simulation approach

The subsurface simulation approach used the GTW tool and is detailed in Leontidis et al., 2025. An estimated demand profile for both 12-hourly demands and monthly average demands was used to simulate the subsurface behaviour and subsequent heat delivery from the existing well for 20 years. The flowrate, pressure drop, and delivery temperature were all simulated to deliver exactly the demanded thermal power over time. The results of thermal heat delivery and outflow temperature can be seen in Figure 2. A coupling with a heat network/heat exchanger simulator was not carried out, but rather, a system was proposed that could handle the required temperatures, pressures, and flowrates for supplying the delivered heat to the newly planned buildings.

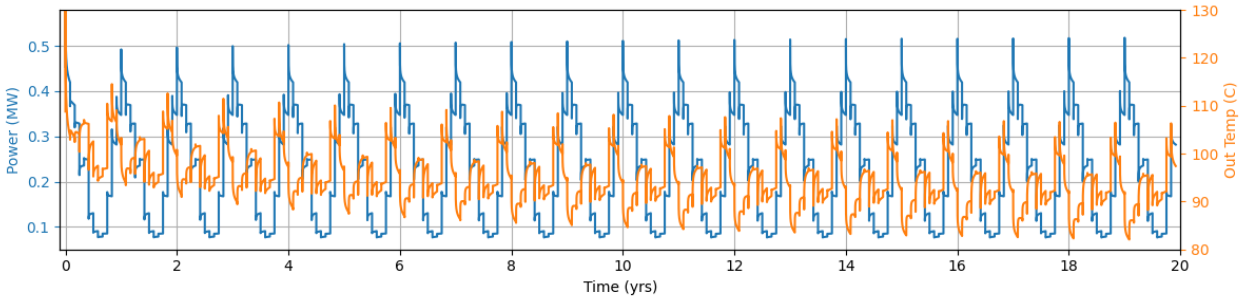


Figure 2. Simulated thermal power and outflow temperature of MOL-GT-03 if completed with the HOCLOOP concept.

4.2.3 Cost analysis

The well is 4,950 m long with a true vertical depth of 4,234 m. Although easily accessible, its existing completion string must be removed before operation, and this cost is excluded from current estimates. As leakage is negligible, the well is assumed suitable for closed-loop circulation without a lower liner. A 4.5" OD DHS is selected to pass the 3,533 m restriction and accommodate the expected low flow rates. Installation can be

performed using a rig-less intervention unit and heavy-duty cranes, with total installation costs estimated at 2.3 M€ (0.1 M€ mobilization, 0.6 M€ well operation, 1.6 M€ equipment and consumables).

In addition, the costs of the two-pipe system, with separate supply and return lines, selected for the district heating network are accounted for. The main section uses DN50 piping, branching near the new buildings into DN32 for one building and DN40 for the other, with identical diameters for internal connections to the technical rooms. To transfer heat while keeping the circuits separate, heat exchangers rated at 560 kW and 750 kW are installed. A circulation pump ensures flow in both the HOCLOOP and district heating circuits, while an expansion system maintains constant pressure by compensating for water expansion as temperature increases.

Finally, the cost for the district heating network installed in the ground including the costs for piping and for the dig works is estimated at 342 k€ whereas it is estimated at 404 k€ when installed above ground.

4.2.4 Discussion

Using the same calculation tool as in the French case, and account for the cost of installing the system in the well, with an additional 300–400 k€ required to deliver the heat to the new buildings, the LCOE for the Belgium case for the reference case is 152 €/MWh. As in the Paris case, a sensitivity analysis was performed to evaluate the impact of the system lifetime on the Levelized Cost of Energy (LCOE). The results indicate that extending the project lifetime significantly reduces the cost of energy. It is estimated at 232, 131 and 113 €/MWh when considering project lifetimes of 10, 30 and 50 years, respectively.

Note that the configuration described in this section addresses heat demand only. The buildings also have a cooling demand, which would need to be met by a dedicated chiller system. Currently an ATES system is installed near the buildings in order to deliver both heating (via a heat pump) and cooling. In addition, the Belgian case is particularly constrained, since the locations of both the well and the buildings were predetermined and not optimal. Furthermore, the system is designed to deliver only heat, whereas the buildings also require cooling. Meeting this additional demand would require further investment in a chiller system. These factors make the business case for the HOCLOOP concept in this configuration less favourable.

4.3 Italian case studies

4.3.1 Integration scenario

The Gavorrano case considers a district heating network (DHN) covering the town of Gavorrano and smaller town in the area powered by a set a of HOCLOOP wells while the Amiata case consists of a set of HOCLOOP wells powering an Organic Rankine Cycle (ORC) and heating the greenhouses of an agricultural company. For further information on the details of the DHN and the ORC plant refer to Fiaschi et al. (2025).

4.3.2 Simulation approach

The well behaviour was analysed using the in-house developed simulation tool, BHEModel2.0. The model integrates the one-dimensional energy and momentum balance equations for the fluid along the well to compute the pressure and temperature profiles. The degradation of heat transfer between the wellbore and the surrounding rock was modelled using a specifically developed correlation Fiaschi et al. (2025). A time-convolution-based approach was implemented to account for the effect of temporal fluctuations in thermal loads. To facilitate the coupling between the surface plant and the well model, the off-design performance of the surface plant was simulated in EES and represented through multiple polynomial correlations. These correlations were used to predict the surface plant performance and cost as functions of the well outlet conditions and the plant design point.

For the Gavorrano case, at least 10 wells are considered to obtain outlet temperatures over 85°C to supply the heat to the DHN operating between the temperatures 80-40°C as shown in Figure 3. The lower mass flow rate circulated in the case of higher number of wells allows to reach higher outlet temperatures and less depletion of the geothermal resource.

For the Amiata case the total mass flow rate needed is fixed monthly by the needs of the agricultural plants, for a certain number of well the total mass flow rate is divided equally between them. This means that for a lower number of wells the mass flow rate circulating is higher. At least 15 wells are needed to provide the necessary heat to the agricultural plant throughout the years with an inlet temperature of at least 90°C. At the same time, in this configuration, the ORC does not operate often in fact it achieves a capacity factor (CF) of 0.18. Increasing the number of wells raises CF; with 20 wells, it reaches 0.6. This occurs because the lower mass flow per well increases outlet temperatures, allowing the ORC to operate under optimal conditions more frequently.

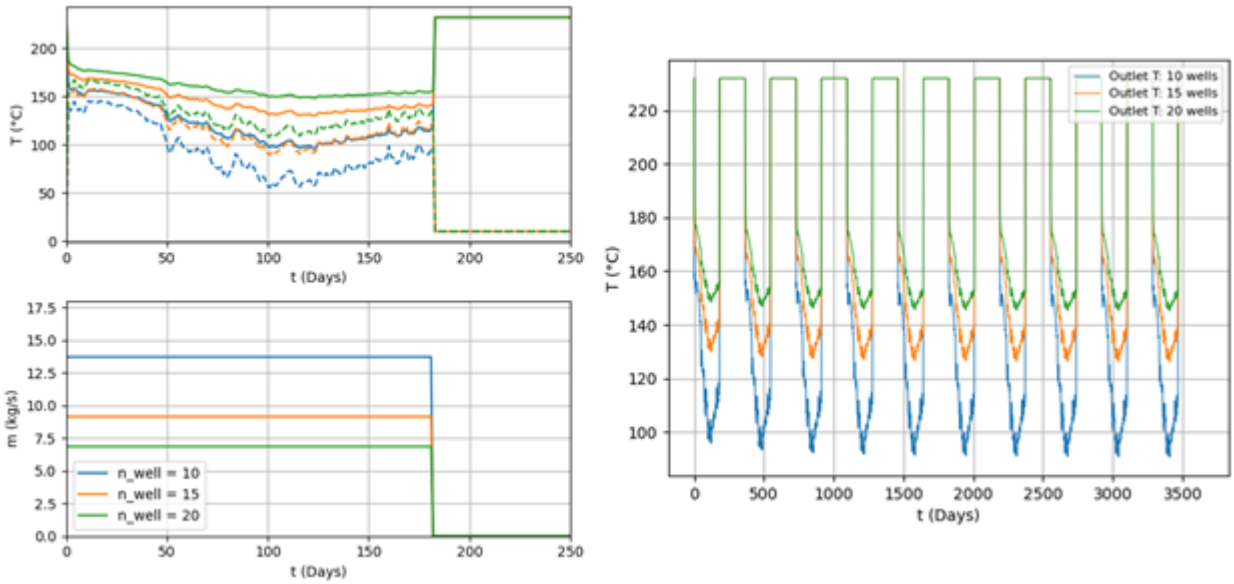


Figure 3. Outlet and inlet temperatures of the wells (top left); mass flow rate per well (bottom right); outlet temperature over the years (right).

4.3.3 Cost analysis

The LCOE is calculated using the approach proposed by Ungar et al. (2023):

$$LCOE = \frac{C_{tot}\beta + \overline{\dot{W}_{tot}}}{\overline{\dot{Q}_{DH}}}, \beta = \frac{1 + \alpha OM_{ratio}}{\alpha h_y}, \alpha = \frac{1 + (1+i)^{-L_e}}{i}$$

where C_{tot} is the total investment cost estimated for the network, $\overline{\dot{Q}_{DH}}$ and $\overline{\dot{W}_{tot}}$ are the annual average heating demand and electrical power, respectively, OM_{ratio} is the annual operation and maintenance rate, set at 5% of the initial investment; Le and i represent the lifetime (20 years) and interest rate (4%). cel = 11 c€/kWh was the average price of electricity in September 2025. Finally, hy = 8760 h/year is the number of hours in a year.

For the well cost estimation, two approaches were applied across the case studies. For both sites, the cost of subsequent wells was reduced by 30% to account for efficiency gains resulting from increased expertise and improved geological understanding.

In the Gavorrano case, relatively standard geological conditions and favourable subsurface temperatures allow the use of conventional horizontal drilling bits, thus drilling costs can be derived from industry experience. The total installation cost for the first well is estimated at €30 million, including €2M for mobilisation and site preparation, €16M for continuous drilling operations, and €12M for equipment and consumables. To meet the district heating network (DHN) demand, 10 wells would be required in the Gavorrano area, bringing the total installation cost to €219 million. Drilling and well installation account for 96.1% of total capital costs, while DHN components (pipelines, heat exchangers, and pumps) represent the remaining 3.9%.

In the Amiata case, conventional horizontal drilling tools cannot be employed due to temperature limitations; therefore, a standard correlation for drilling cost was applied to obtain a reasonable estimate of the overall system performance. The wells drilled are assumed to be of length of 4700 m, divided in a vertical section of length 2200m and a horizontal section 2500 m long. The diameters for the vertical section and horizontal section are 24.4 and 21.7 cm respectively. Applying the cost correlation described in Leontidis et al. (2025), the total cost per well is estimated at 17.3 M€. Assuming a 30% cost reduction for each additional well after the first, the total investment amounts to 186.84 M€ for 15 wells and 247.39 M€ for 20 wells.

For the Amiata case, where cogeneration is possible, the net power output may be negative, indicating electricity sales. This reduces the overall LCOE, assuming the main objective remains heat production, with electricity sales as an additional revenue source. The capital investment includes the wells, the ORC plant, and the pipelines connecting the wells to the power plant and agricultural facilities. No extra costs are considered for heat use, as the plant is already in operation. Both the 15- and 20-well configurations are evaluated. While the costs of wells, pipelines, and heat exchangers remain fixed, the ORC capacity and inlet conditions vary, causing the total cost to fluctuate but generally decrease over time. In both cases, the maximum investment occurs at

the start of operation. A higher number of wells increases the ORC size and cost, as more power is produced. However, overall, well drilling and installation is about 95% of the total investment in both configurations.

4.3.4 Discussion

Applying equation (1), the LCOE for the Gavorrano case is 268.8 €/MWh. The same formula is used for the Amiata case, where the heating demand corresponds to that of the agricultural plant, and ($\overline{\dot{W}_{tot}}$) is the net power output, i.e., the difference between the circulation pump consumption and the ORC average power output. Due to the lower well installation costs, the LCOE for Amiata is significantly lower than that of Gavorrano: 77.63 €/MWh for the 15-well configuration and 96.22 €/MWh for the 20-well configuration. The increase in ORC power output resulting from additional wells does not sufficiently offset the higher capital costs, preventing a reduction in the overall LCOE. For the 20-well case, the electricity produced would need to be sold at an incentivized price (c_el = 524 €/MWh), well above market levels, to achieve parity with the 15-well case.

Overall, economic feasibility is strongly influenced by the drilling and installation costs, which represent the largest share of the investment, and by the quality of the geothermal resource. In Amiata, the favourable geothermal gradient enables the use of shorter wells, reducing drilling costs and resulting in a lower LCOE than that of the Gavorrano DHN.

4.4 Polish case study

4.4.1 Integration scenario

Several integration options were evaluated, including direct connection to the municipal heating plant, the nearby airport, and setups with or without heat pumps. These scenarios assess the flexibility of integrating HOCLOOP units into existing energy infrastructure. Although multiple units would be needed to meet total demand, the current analysis focuses on a single unit.

4.4.2 Simulation approach

First, the performance of a single HOCLOOP unit was evaluated using the numerical model GWellFM (Leontidis et al., 2025). Each unit features a 7,000 m well trajectory, including a 2,500 m horizontal section, with water as working fluid. Flow rates from 10 to 60 m^3/h were tested, with an optimal rate of ~20 m^3/h yielding stable power of ~1.6 MW and temperature above 95°C, sufficient to preheat district heating return water (Figure 4), which has temperature in the range of 45-72°C. This flow rate also enables thermosyphon-driven circulation, eliminating the need for pumping power.

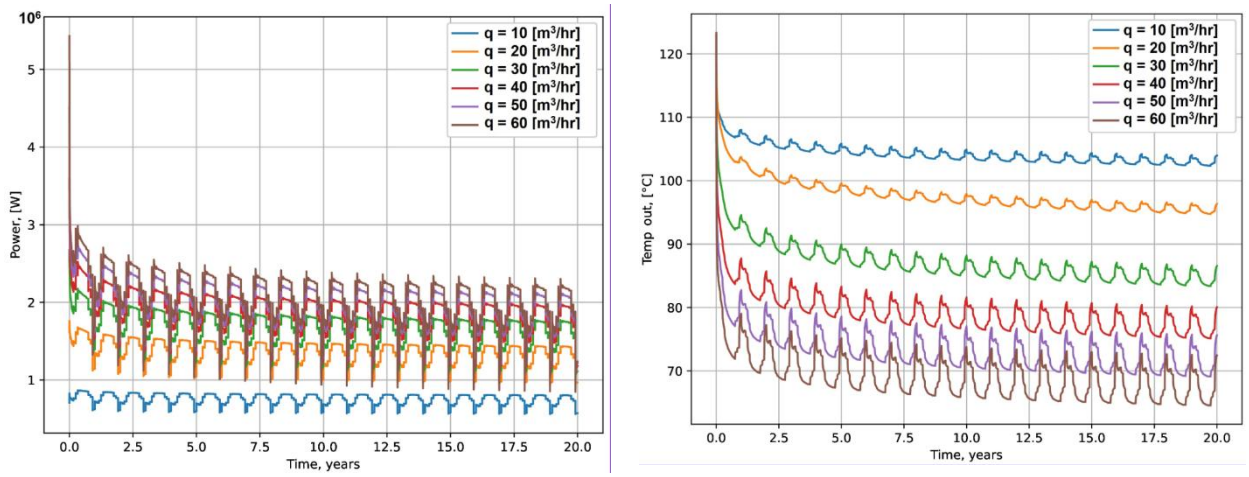


Figure 4 Influence of flow rate on output temperatures and power for the salt dome case considering a 2500m horizontal section.

Two geothermal energy utilisation scenarios were analysed: one with and one without heat pumps. In both cases, the first stage involves direct heat exchange, while the second scenario adds heat pump integration. Although heat pumps enable higher thermal output, they also entail higher electricity consumption and investment costs. The share of renewable energy in the system, with total used capacity ~19 MW (18 MW for heating and 1 MW for hot water) and energy production of ~204 TJ/year, without heat pumps is estimated at approximately 44%, compared to about 52% with heat pump utilisation. Notably, incorporating heat pumps

increases the renewable share beyond 50%, meeting the threshold for an energy-efficient heating system as defined by the Energy Efficiency Directive (recast) – EED 2023/1791.

4.4.3 Cost analysis

In the Polish analysis, it is assumed that the hypothetical consumer currently uses heat from a hard coal-fired district heating system. This consumer would disconnect from the district heating network and instead use energy from a single HOCLOOP module equipped with heat pumps and a direct heat exchanger.

The financial assessment covers a 30-year period. The cost of a single HOCLOOP unit was estimated at 21 M€, including 2 M€ for mobilisation and demobilisation, 8 M€ for drilling and well operation, and 11 M€ for equipment, tubulars, and consumables. The HOCLOOP unit is assumed to operate with treated, high-quality water, and with cost-free energy production at flow rates below 20 m^3/h, thanks to thermosyphon effect. Although operating costs are lower than for coal-based systems, high capital expenditures make the total cost higher overall. Moreover, the distance between the salt dome zone and the Goleniów heating plant poses an additional technical constraint. Over a 30-year horizon, achieving a net present value (NPV) of zero at a 5% discount rate requires 70–80% investment subsidies. Under these conditions, the simple payback time (SPBT) is estimated at 15–16 years.

4.4.4 Discussion

Independent of the existing infrastructure conditions in Goleniów, calculations were carried out assuming an optimal match between the energy user and the deep heat exchanger's performance in terms of power and temperature. A hypothetical 3 MW heating system designed for 90/70°C parameters was analysed. The economic performance of coupling such a system with a HOCLOOP module proved significantly better: the simple payback time reached approximately 29 years without subsidies, and the net variable cost of energy (excluding OPEX and CAPEX) was about 21.2 €/MWh (assuming 30 years lifetime), compared to ~130 €/MWh for natural gas.

The results underline the strong cost-effectiveness potential of the HOCLOOP solution, provided it is coupled with a suitably matched energy recipient. The optimal capacities and temperatures correspond to those of small, local coal-fired heating plants, offering promising opportunities for replication under Polish conditions.

5 CONCLUSIONS

The comprehensive techno-economic analysis of HOCLOOP implementation across five European pilot sites reveals both the potential and challenges of deploying horizontal closed-loop geothermal systems in diverse geological and economic contexts. The study demonstrates that while HOCLOOP technology offers significant technical advantages, particularly in terms of environmental sustainability and operational reliability, economic viability remains strongly dependent on site-specific conditions and market factors.

5.1 Comparative Energy Cost Analysis

The levelized cost of energy (LCOE) varies substantially across the pilot sites, reflecting differences in geological conditions, drilling costs, and integration opportunities:

- French case : 378.9 €/MWh. High drilling costs and a low geothermal gradient make the system economically challenging compared to current doublet systems.
- Belgian case : 152.5 €/MWh (estimated based on 2.7 M€ total investment for 300 kW average output). More competitive due to reuse of existing dry well and direct building heating application with low temperature requirements. A district heating network is needed as the dry well is about 1 km from the buildings to be heated.
- Italian Gavorrano case : 268.8 €/MWh. High cost due to high drilling costs in hard formations and high original rock temperature.
- Italian Amiata case : 77.63 - 96.22 €/MWh. Competitive with other technologies due to the lower cost of the wells and high geothermal gradient (122.3°C/km). The increase in power output of ORC does not justify the increase in capital cost.
- Polish case : 57 - 72 €/MWh, total cost, 30 years lifetime, depending on integration scenario. Favourable geological conditions in salt structures are offset by high capital costs, requiring subsidies for economic viability.

The energy cost calculations presented in this study were conducted based on a 20-year project lifetime (30 year for the Polish case), which represents a conservative yet standard approach for infrastructure investment analysis. While extending the economic analysis to consider a 50-year project lifetime an admittedly optimistic assumption given the uncertainties inherent in such long-term projections would yield an energy cost approximately 25% lower than the reference case.

5.2 Key Success Factors

The analysis identifies critical factors for economically viable HOCLOOP deployment: 1/ high geothermal gradients (>3°C/100m) to maximize thermal extraction, 2/ favourable drilling conditions to minimize capital costs, 3/ direct integration with low-temperature heating systems (<70°C), 4/ reuse of existing wells or infrastructure where possible and 5/ access to renewable energy incentives or carbon pricing mechanisms.

5.3 Market Positioning

HOCLOOP systems show the greatest promise in niche applications where conventional geothermal is not feasible due to hydrogeological constraints, and where environmental considerations justify premium energy costs. The technology is particularly suited for dedicated heating networks serving energy-efficient buildings with low-temperature requirements, rather than retrofitting existing high-temperature district heating systems.

5.4 Recommendations

Future deployment should prioritize sites combining favourable geological conditions with supportive economic frameworks. The high capital intensity of HOCLOOP systems necessitates innovative financing mechanisms, potentially including green bonds, carbon credits, or public-private partnerships. Technological improvements focusing on drilling cost reduction and heat extraction efficiency enhancement will be crucial for improving economic competitiveness. The study confirms that while HOCLOOP represents a technically viable solution for sustainable geothermal energy extraction, achieving widespread commercial deployment will require continued technological development, strategic site selection, and supportive policy frameworks that recognize the long-term environmental benefits of carbon-free heating systems.

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