Geothermal district heating: energy, environmental and economic analysis of a case study in northern Italy.

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Abstract. Geothermal district heating is a technology that has been established for over 50 years and offers a number of significant advantages. It allows multiple homes to be converted to renewable energy sources simultaneously, allows a stable heat supply with long-term fixed prices, and generally presents lower risks. The utilization of geothermal energy as a heat source for the network can be considered cost-free during operation, but has a critical economic aspect related to the initial investment. Geothermal district heating networks are in fact capital-intensive systems (CapEx), requiring substantial investments for the installation of the geothermal infrastructure. However, operating costs (OpEx) are significantly lower compared to conventional systems. This study examined the implementation of a district heating network in a medium-sized city in northern Italy. An energy and environmental impact assessment was conducted to determine the optimal plant configuration that maximises the use of the geothermal resource and minimises greenhouse gas emissions. Additionally, a sensitivity analysis was carried out to assess the impact of market variables on the overall cost of implementing the district heating network. This included an evaluation of changes in investment costs in response to variations in the value of electricity taxes -*oneri di sistema*-, of the revenues from the sale of thermal and electrical energy, as well as of the fuel costs. This study aims to provide a complete and detailed overview of the energy, environmental and economic implications associated with the implementation of a geothermal district heating network

Key words: Geothermal, District Heating Network, Renewable Energy, System Charges, Economic Analysis.

1 Introduction

The goal of climate neutrality in Europe has been shown to require 880 to 1100 TWh/year of geothermal heat by 2050 [1]. In recent years, the global adoption of deep geothermal heat is increasing due to advances in heat exchange and drilling technologies, intensified exploration of geothermal sources, and improved documentation of geothermal heat reservoirs [2].

Deep geothermal energy is a reliable, low-carbon source of heat that can be used as a heat source for local district heating. District heating can contribute to the reduction of greenhouse gas emissions in the heating sector, especially when the heat comes from renewable energy. However, the potential of deep geothermal energy to be used as an alternative to conventional centralized heat supply is still under-exploited.

In Italy, according to the Associazione Italiana Riscaldamento Urbano [3], there were 423 district heating systems in 2021. According to GSN data for 2019, district heating covers about 2 % of heating and hot water demand. From the point of view of energy sources, Italian district heating systems are powered at 73% by fossil fuels, represented almost entirely by natural gas, and the remaining 27% by renewable sources, which include municipal solid waste (15.4%), bioenergy (9.5%), geothermal energy (1.4%) and in percentages of less than 1% heat recovery from industrial processes and solar thermal energy.

These figures show that, although geothermal energy has more than doubled its contribution to district heating sources over the past ten years, it remains marginal overall. The two main district heating systems exploiting deep geothermal sources in Itay are the ones in Ferrara and in Vicenza, where the geothermal contribution to the final heating energy supply is equal to 52% [4] and 11% respectively [3].

Geothermal district heating could play an important role towards climate change mitigation, but its slow uptake implies that it is cost competitive only under specific sets of conditions, including drilling success and design of the district heating. Yet, even when geothermal district heating is less cost competitive than other alternatives, development costs bring indirect economic impact that could also benefit domestic economy.

The aim of this work is to evaluate both the design and economic feasibility of a district heating network based on deep geothermal energy. It analyses the possible exploitation of a geothermal resource located in a medium-sized town in northern Italy, and its implementation in a district heating network to supply heat to an important part of the town. The case presented then becomes a pretext to show, in the concluding part of the study, the impact of energy market developments on commodity prices and the feasibility of renewable, especially electricity-based, projects.

The economic viability of district heating projects fed by heat pumps is in fact always threatened by the high cost of purchasing electricity, including system taxes, so called “oneri di Sistema”, for operators. This high purchase cost of electricity means that district heating operators usually combine the heat pump with dedicated cogeneration systems, mostly gas-based, to produce their own electricity at a lower price. A nonsense that ensures the economic viability but also an unavoidable presence of fossil source consumption in order to use a renewable technology.

Several northern European states, Denmark and Finland [5] for example, since the elimination of taxes on the electricity supplying heat pumps for district heating networks, have seen an exponential diffusion of these systems with a consequent growth of the renewable share in the networks and increased possibilities of sector coupling, power to heat, in the national energy system. To date, the system charges on the electricity tariff for the operators are an important barrier for the realization of heat pumps in Italian district heating networks and consequently for geothermal projects. The sensitivity analysis with respect to electricity taxes and commodities price proposed in this paper aims to show the effects of these on the feasibility of renewable projects.

2 Outline of the study

The work is based on the analysis of a specific case study, the possible exploitation of the geothermal resource for a district heating network in a small to medium-sized town in northern Italy, where a feasibility analysis is currently ongoing and an exploration phase is foreseen. Four possible plant alternatives are analyzed and compared, with the aim to maximize the geothermal heat utilization. Once the three alternatives are defined, an environmental analysis is conducted to determine the CO_2 emissions for each case and to define which alternative has the least environmental impact.

Finally, the economic feasibility of the geothermal district heating system is assessed comparing the economic performances of the two alternative solutions where electrical power to feed the heat pumps is either self-produced via a cogeneration system or bought from the electrical grid. Three possible cost scenarios for electricity and natural gas are illustrated and a sensitivity analysis is performed on electricity purchase taxes. This last point of analysis answers the research question included in the introduction, i.e. to understand how the energy market, the costs of energy carriers and taxes, especially those on electricity, influence the feasibility of using renewables and heat pumps on a large scale.

2.1 The model

The feasibility of the geothermal plant under study is analysed from the energy, economy and environmental impact. To do so, a dynamic energy model is necessary to simulate the performances of the different alternative technological solutions here foreseen. The plant operation simulations of the proposed alternative solutions have been carried out with Energy Pro software.

EnergyPRO is a dynamic simulation software and at the same time an economic optimization tool of the operating logic of the plant: in fact the simulation model includes the implementation of management logics optimized with respect to the market conditions. By including the electricity market in the optimization, the software manages the operation of the plant, hour by hour, activating the generation system during the lowest cost of production periods.

Figure 1 shows the software interface for the first proposed solution, that is presented in detail in the following chapter. The model is built to reproduce the first plant scheme, which includes two boilers, a co-generator, and an heat pump. For the boiler, the software allows you to define one power for heat and one for fuel, thus defining an efficiency. For the co-generator, it is possible to set an electrical power, a thermal power and a fuel power, thus defining the efficiency. For heat pumps, a maximum heat capacity, COP and the temperatures between which the heat pump operates can be set. However, it is not possible to set the partialisation level of the heat pump. For this reason, both non-partilisable and partilisable heat pumps are included in the model, to simulate a partilisation between 50% and 0%.pumps.

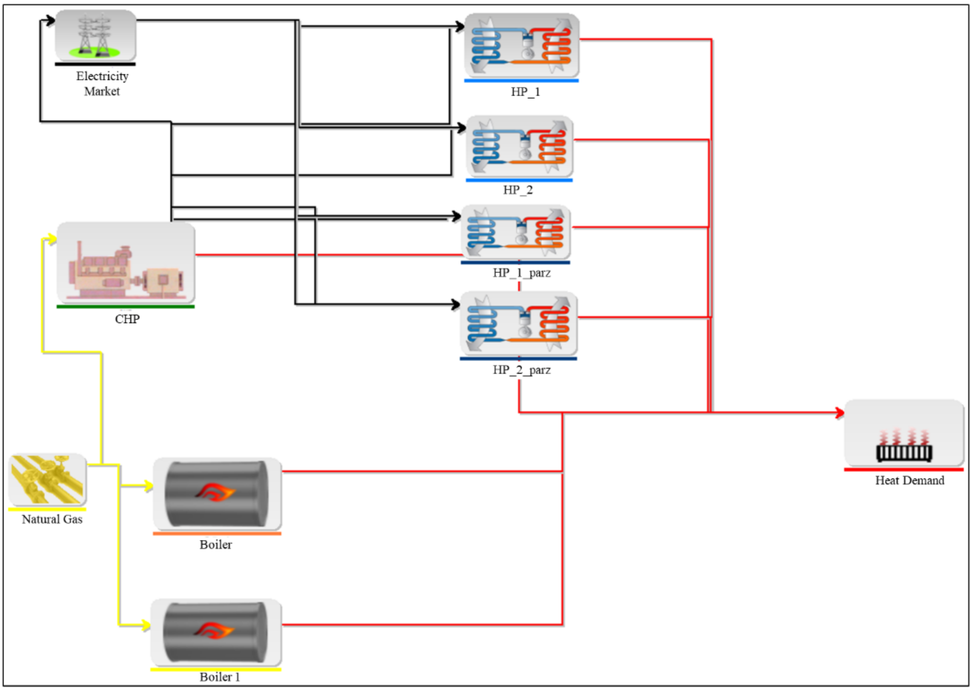

Fig. 1. Energy Pro interface of the first solution plant layout.

The heat pumps are connected both to the co-generator and to the power grid for the supply of electricity. The choice was made to use an expected value of 2030 as the PUN (Single National Price) for the price of electricity on the Italian market. Based on assumptions and investigations carried out in previous projects by the authors [6], an average value of 93 €/MWh was used as an estimate of the electricity price in 2030. This average value was used to obtain the annual trend of the PUN expected in 2030.

As far as natural gas is concerned, a purchase price in 2030 of 0.56 €/Sm^3 has been estimated. Based on the hourly energy and natural gas prices, the Energy Pro software manages the operation of the plant, hour by hour, activating the generation system during the periods of lowest production cost.

3 Case study

The case study consists of a feasibility project for a district heating network supplied by geothermal sources, located in northern Italy.

In this area, a geothermal source was identified at a depth between 1500 m and 2000 m. The source is expected to have a temperature of 60 °C and the design flow rate is evaluated as 180 m^3/h. Both data are affected by some uncertainty, that will be reduced after exploration. The district heating network is sized with a supply temperature of 90°C and a return temperature of 65°C. The district heating system's annual heat demand is 49075 MWh/y, of which network losses account for approximately 8%. Thus, the heat demand of the consumer is 44922 MWh/y, with a thermal power supplied to the network, including network losses, of 24 MW.

Table 1 summarises the main project data.

Table 1. District heating network design data.

Geothermal resource	
Depth of geothermal resource	1500 -1600 m
Temperature of geothermal resource	60 °C
District heating network	
Supply temperature	90 °C
Return temperature	65 °C
Heat demand including network losses	49075 MWh/y
Heat demand	44922 MWh/y
Thermal power	24 MW

3.1 Plant alternatives and energy performances

Starting from these design data, four different possible plant solutions were simulated, namely:

- first solution: basic solution consisting of co-generator, heat pumps and boilers;
- second solution: a thermal storage is added to the first plant configuration;
- third solution: a small heat pump is added to the first plant configuration
- fourth solution: without co-generators, but only heat pumps and back-up boilers

The *first* proposed *solution* consists of two heat pumps with a total of 11 MW that use geothermal source, and a 4.3 MW electrical and 4.3 MW cogeneration system. Each heat pump is supplied at the evaporator by the geothermal source, while the cogeneration engine, powered by natural gas, produces hot water for the district heating system and electricity to power the heat pump system. There are also two 4.5 MW boilers each for the production of hot water powered by natural gas, with the function of load integration at peak times and in the absence of geothermal sources. The thermal power plant's installed capacity is approximately 24 MW. The system layout is shown in Figure 2.

The results of the simulations performed on this type of system show that heat pumps cover 37,5% of the total demand, while the remaining 62,5% is produced by boilers and the natural gas-fuelled co-generator, as shown in Figure 4.

This is due to the fact that boilers are used to cover the base load during the summer period and to meet peak demand. The use of the boilers alone during the summer period is a great limitation on the possible utilisation of the geothermal resource.

The system is supplied at 23 %, by geothermal energy, and the remaining 77 % by fossil fuels. Since the geothermal energy supplies the heat pump system, which only produces heat, 23 % of the heat demand of the district heating network would be covered by renewable sources. From this point of view, the project is in an intermediate position between the two main Italian examples of geothermal district heating in Ferrara and Vicenza, mentioned in the Introduction.

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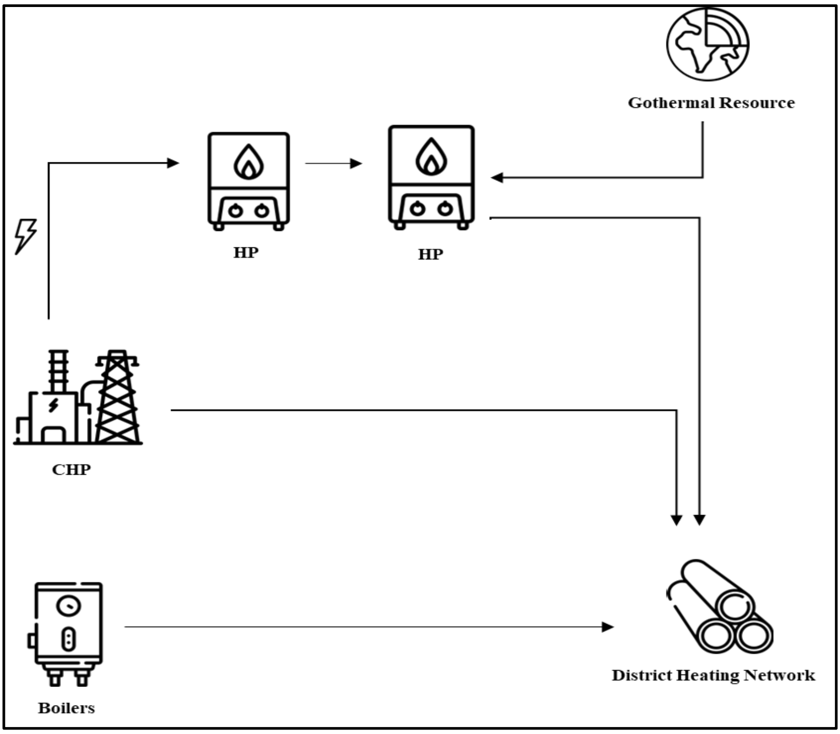

Fig. 2. Plant layout of the first solution involving co-generator, hat pumps and boilers.

The *second solution* involves the installation of thermal storage used to store the energy produced by the heat pump system and the co-generator. The heat pumps do not allow total load partialization and this does not allow them to be used to cover the summer load, which amounts to approximately 1.4 MW. As the heat pumps have a larger summer load size, a heat storage tank is introduced to store the excess energy produced by the heat pumps and return it when needed to cover the summer load.

For the sizing of the thermal storage, several simulations were carried out keeping the same plant layout but using increasing storage sizes. The results obtained were related to the energy produced annually using the boilers. The graph in Figure 3 supports the choice of using 100 m^3 storage tanks, as production by boilers decreases significantly with small sizes, and then remains more or less constant for larger sizes.

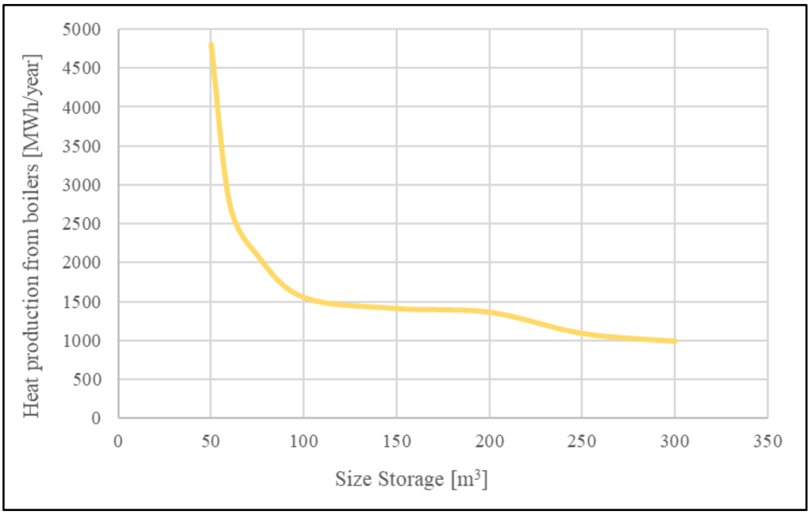

Fig. 3. Trend of heat production by boilers as a function of heat storage size.

With this configuration, the use of the boilers decreases significantly from 22% to 3%, as boilers are no longer used to cover summer load but only peak demand. This is because heat pumps powered by the geothermal resource are now used for heat production during the summer period, thanks to thermal storage that is charged and discharged daily. Production from heat pumps increases from 42% to 72% as shown in Figure 4. This solution makes greater use of the available geothermal resource, which thus covers 54% of the district heating network's heat demand.

The *third solution* involves the installation of a small heat pump to cover the summer load. The summer load is approximately 1.4 MW and therefore a heat pump of 1.5 MW and COP equal to 4.1 is installed. In this way, the heat pump system can cover the heat load throughout the year, minimizing the use of boilers.

The use of boilers for the production of thermal energy has decreased significantly, providing a coverage of only 7%. Compared to the previous case where storage was added to the plant scheme, in this case energy production through the co-generator was reduced by up to 17%, thus decreasing the use of natural gas as a primary source. This resulted in a significant reduction in CO_2 emissions. So, this solution allows to maximise the use of heat pumps and reduce the use of boilers and co-generators, thus providing a greater use of the geothermal resource and a lower dependence on natural gas. In this scenario, in fact, 57% of the heat demand is covered by geothermal energy.

In addition, the analysis of the load duration curve in Figure 5 shows that the heat pump added in this alternative is able to cover perfectly the summer load, related only to the production of domestic hot water, and to guarantee coverage of the base load during the rest of the year. Thus, this solution allows the use of heat pumps to be maximised and the use of boilers and co-generators to be reduced, thus guaranteeing greater utilisation of the geothermal resource and less dependence on natural gas.

The *fourth solution* does not involve the installation of a co-generator, but only heat pumps and back-up boilers. The plant sizing remains the same, so the size of the heat pumps (11 MW) and boilers (9 MW) is the same as in the first solution. In this case, the electricity required to power the heat pumps is all purchased from the grid.

The results in Figure 4 show that, in this case, production from heat pumps covers 78% of the heat demand and boilers 22%. This is because boilers cover the summer heat demand

and peak demand, and the demand that was previously met by the CHP is now covered by heat pumps. This maximises the use of the geothermal resource and decreases the use of natural gas.

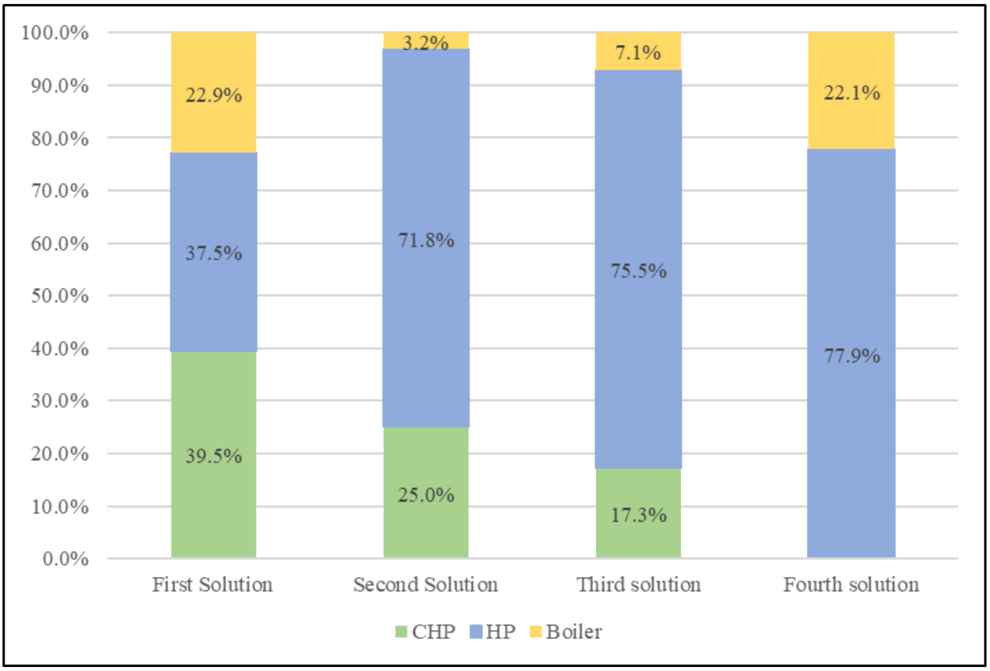

Fig. 4. Trend of heat production by boilers as a function of heat storage size.

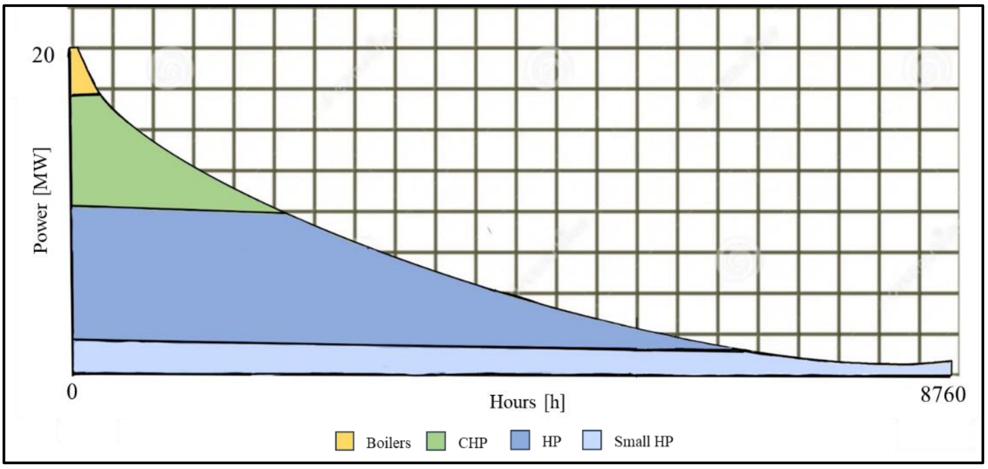

Fig. 5. Duration curve of the third solution

3.2 Environmental performances

The equivalent CO_2 emissions generated by the different proposed solutions are compared. Specific emission data [7] referring to the year 2020 are used as inputs: 268 gCO_2eq/kWh considering extraction, distribution and combustion for natural gas and 492 gCO_2eq/kWh for electricity, are summarised in Table 2.

Table 2. Specific CO_2 equivalent emissions for natural gas and grid electricity

Specific emissions (gCO_2eq/kWh)	**2020**
Natural Gas	268
Electric Energy	494

The results obtained from the simulations, shown in Figure 6, were compared with the individual solution of installing individual boilers for each user. They show that the second, third and fourth proposed solutions result in a significant decrease in CO_2 emissions. This is due to the increased use of the geothermal resource and the increased use of heat pumps and electricity as a primary source, resulting in a reduction in the use of boilers for thermal energy production. The solution involving the addition of thermal storage reduces emissions by about 37%. The alternative involving the installation of an additional heat pump has even more positive effects. This solution further reduces the use of cogeneration and thus natural gas as a primary source and reduces emissions by 51%. Furthermore, the fourth solution, without the use of the co-generator, has the lowest amount of emissions due to the use of natural gas.

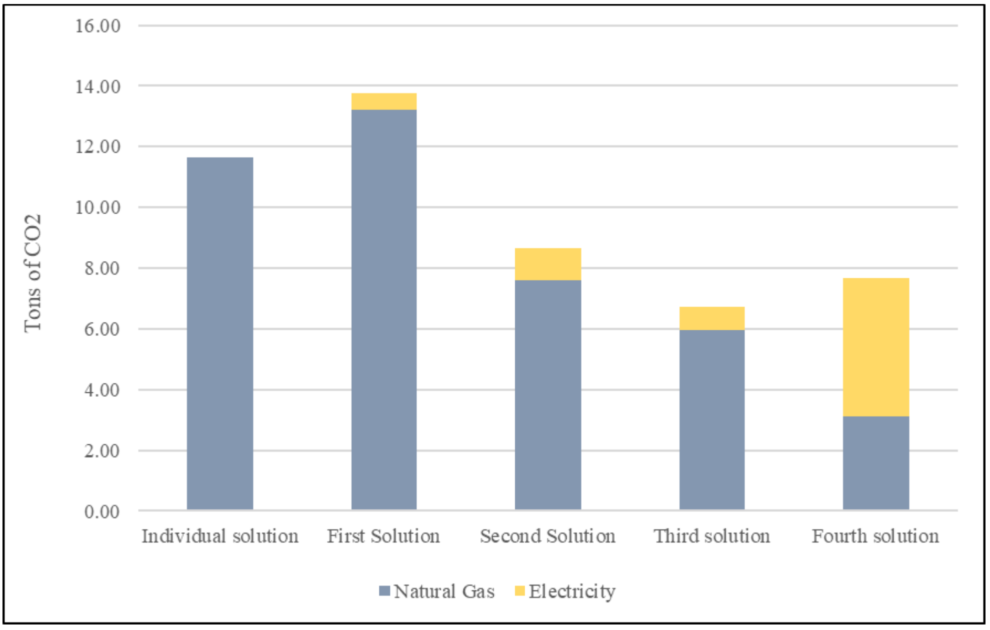

Fig. 6. Comparison of 2020 CO_2 equivalent emissions from natural gas and electricity for the four proposed solutions

In conclusion, these results demonstrate how the implementation of alternative solutions, such as the use of heat pumps and renewable energy sources, can contribute significantly to the reduction of CO_2 emissions.

3.3 Economic analysis

The utilisation of geothermal energy as a heat source for the district heating network can be considered zero-cost during operation, but has a critical economic aspect related to the initial investment. Geothermal district heating networks are in fact systems that require substantial investment for the installation of the geothermal infrastructure. Therefore, they are capital-intensive (CapEx). However, the operating costs (OpEx) are significantly lower than in conventional systems.

In this chapter, the economic analysis for the first solution is performed. A sensitivity analysis is then performed with respect to energy and natural gas costs and electricity taxes, comparing the first solution and the fourth solution. The first using the co-generator and the fourth without using the co-generator.

Regarding the initial investment costs, the first plant scenario has an investment that amounts to 25 M €. This value is mainly due to the costs of the production plant, which amount to 13 million euros. The cogeneration plant costs 3 million euros and the heat pump system about 5.5 million euros. The other main costs are for the distribution system and the drilling of geothermal wells, and are summarised in Table 3. The values are estimated using the Danish Energy Agency's technological catalogue as a source for specific costs [8].

Table 3. Summary of the investment costs of the first proposed scenario [M€].

Items	Total
Geothermal well drilling and geothermal circuitry	5 M€
Geothermal power plant	13 M€
Distribution system	5.5 M€
Engineering activities	1.5 M€
Investment cost net of geothermal contribution	25 M€

With regard to operating costs, the revenues and operating costs incurred by a geothermal district heating production plant are analysed.

The revenues due to the construction of the plant essentially consist of:

- Revenues for the sale of thermal energy to the district heating system
- Revenues for the sale of electrical energy to the public grid
- Tax credit for geothermal district heating
- White certificates C.A.R
- White certificates heat pump

Operating costs consist of:

- Fuel cost for cogeneration system and boilers
- Cost of purchasing electricity from the grid
- Full service maintenance cost of cogeneration engine
- Other equipment maintenance cost
- Major overhaul cogeneration plant

Concerning fuel and electricity purchase costs, values were estimated for 2030. For the purchase price of natural gas, a value of 0.56 €/Sm^3 was estimated, while for the purchase of electricity from the grid, a value of 113 €/MWh was estimated, of which 20 €/MWh was to be attributed to energy taxes [3].

Table 4 summarises the cash flows related to the purchase of electricity and natural gas and the sale of thermal energy to consumers and of electricity to the national grid. The total, however, refers to the total revenues and costs related to the production plant.

Table 4. Summary of the operating costs of the first proposed scenario. Only costs and revenues related to natural gas and electricity are presented in the table.

Revenues	**Value**	**[]**	**Quantity**	**Annual Cost**
Thermal energy sold to the consumer	**114**	€/MWh	44922	3 818 370 €
Sale of electricity to the grid	**93**	€/MWh	9361	795 685 €
			Total	**5 882 777 €**
Cost	**Value**	**[]**	**Quantity**	**Annual Cost**
Fuel for CHP	**0.56**	€/Sm3	4156289	2 327 521 €
Fuel for Boilers	**0.56**	€/Sm3	912339	673 309 €
Electricity from the grid	**113**	€/MWh	276	31 188 €
			Total	**3 856 019 €**

The results obtained from the economic analysis, based on the use of the proposed 2030 costs, are shown in Table 5. Analyses were carried out considering an investment period of 23 years, including 3 years of design and 20 years of operation.

Table 5. Results of economic evaluation indices.

PBT	10.25
NPV	17 281 702.86 €
IRR	8.36%

These results show that the project could be profitable, even considering the changes in the energy market by imagining an increase in utility tariffs.

3.4 Sensitivity analysis on fuel cost and taxes

A critical aspect of the economic analysis is the purchase price of fuel and electricity and the taxes related to the purchase of energy from the national power grid.

Then, with regard to operating costs, a sensitivity analysis was carried out on the costs of purchasing electricity from the grid and fuel. Three different scenarios were considered: a conservative scenario, named l*ow,* which corresponds to market conditions prior to 2022, a *high* price scenario, corresponding to the rise generated in the last two years of the energy crisis, and a *medium* scenario*,* which corresponds to a future estimation of prices, increased with respect to the pre-crisis period, but stabilised and lower than last year. For each of these scenarios, an analysis of the impact of the value of electricity tariff was conducted. The *'medium'* scenario refers to the costs estimated in 2030 and used in the economic analysis described in the previous paragraph.

The electricity and fuel prices are summarised in Table 6.

Table 6. Estimated electricity and natural gas prices to 2030 under three different scenarios.

	Low	**Medium**	**High**
Natural Gas [€/Sm³]	0.33	0.56	0.78
Electricity [€/MWh]	57	93	127

It is assumed that changes in the tariffs for the purchase of natural gas and electricity can influence the heat tariff for the customers as it is today. It is important to consider that the tariffs for the sale of heat are influenced by multiple factors but generally updated according to the market price trend of natural gas. Therefore, in order to provide an estimate of the possible sales tariffs of thermal energy sold to the utility, a proportional calculation was made with respect to the tariffs proposed in the base scenario. Hourly selling prices of electricity to the grid are obtained from simulations in Energy Pro but are generally equal to the purchase price of electricity from the grid net of system charges.

In *fourth solution* there is the decrease of the initial investment due to the non-purchase of the co-generator. It goes from an investment of 25.7 M€ to an investment of 22.7 M€.

The simulations and economic analysis performed for the 1st and the 4th plant alternatives for each energy cost scenario and each taxes value produced the results shown in Figure 7. The payback times obtained from the economic analysis for each scenario are reported as a function of the electricity taxes.

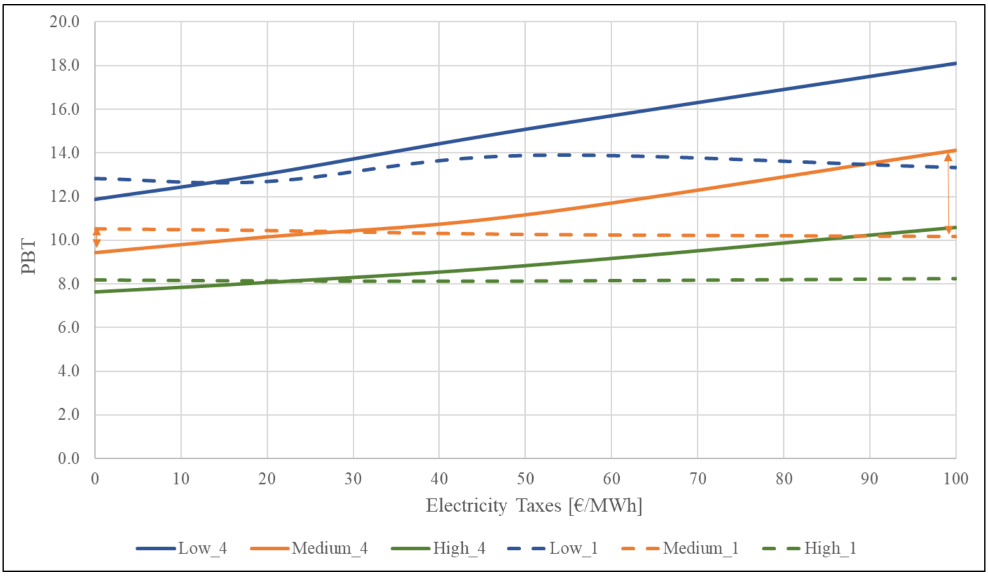

Fig. 7. Comparison of the payback time of the two scenarios with the three price assessments for natural gas and electricity.

Regarding the *first solution*, the 'high' case is the one with the lowest payback time. This is because it has higher prices for natural gas and electricity, it also has a higher price for selling thermal energy to consumers which is related to the current price of the individual alternative heating solution, the gas boilers e.g.. This means that in a high price scenario, as it as been in the past two years, the collective solution of district heating system has the more interesting economy than the individual solution. Moreover, as electricity taxes increase, the performance of the 'high' scenario remains more or less constant, as the purchase price of electricity from the grid is very high, it is almost always cheaper to produce it with the cogeneration self production plant. Thus, the increase in system charges does not affect the return on investment if the tariffs are high.

As fuel and electricity prices decrease, the payback time increases. In fact, the 'medium' scenario has longer payback times than the 'high' case and shorter than the 'low' case. Also in this case, both scenarios have an almost constant trend as the electricity tax changes since the majority of electricity is self-produced with cogeneration plant.

In the *4th solution* with the elimination of the co-generator, the impact of electricity taxes is more evident: the three trends are no longer constant, but increase as the system charges increase. Again, the solution with the lowest payback time is the one with the highest charges. The heat pump-only solution without a co-generator is most cost-effective when system charges are zero or very low (as low as 20 €/MWh). This is because the heat pump-only system has a lower investment cost but only works by purchasing electricity from the grid. Therefore, it only has a lower operating cost when system charges are very low. On the other hand, with higher electricity taxes, the solution involving the use of the co-generator in the system is more convenient.

This is actually what happens in some Northern European countries, such as Denmark, where to incentivize the use of heat pumps and more renewable solutions the tax on 'electricity for heat production' has been reduced to 1 €/MWh [5]. This analysis shows that in case of reduction or elimination of electrical taxes for power used for heat pumps in district heating would make it feasible to eliminate natural gas for cogeneration self-production of electricity or, the other way around, the presence of the current taxes on electricity for utility make the presence of a fossil fuels base cogeneration system mandatory to guarantee the economic sustainability of the project decreasing the environmental performances.

4 Conclusion

The objective of this work was to evaluate the feasibility of a district heating network based on geothermal resources, both from a design and economic point of view.

From the point of view of the production plant, four different types of plants were evaluated.

1. The first solution involves the installation of a co-generator and boilers powered by natural gas, and the use of heat pumps to exploit the geothermal resource.
2. The second solution involves adding the installation of thermal storage to store the heat produced by the heat pumps.
3. The third solution involves the addition of a small heat pump to the plant layout.
4. The fourth solution does not involve a co-generator but only heat pumps and back-up boilers.

The first solution uses heat pumps to satisfy 42% of the total demand. This is due to the fact that the size of the heat pumps is higher than the summer base load and therefore boilers are used to meet the summer demand.

The introduction of thermal storage in the second solution allows the energy produced by the heat pumps to be stored and thus increase energy production from the geothermal resource. In this scenario, production from heat pumps covers 72% of the thermal demand, with a significant reduction in the use of boilers. Thus, the geothermal resource contributes 57% of the heat production. This shows that solutions can be found that utilize more renewable (geothermal) energy and reduce the contribution of natural gas used by the co-generator. These solutions also significantly reduce greenhouse gas emissions from the plant, as highlighted in the environmental analysis in Chapter 4.

From an economic point of view, it is confirmed that the initial investment to set up a district heating network based on a geothermal resource is very significant, due to the exploration and drilling phase of the geothermal resource. However, operating costs (OpEx) are significantly lower compared to conventional systems. This implies that the project is economically feasible even in the basic solution, with a payback time of 10 years and a Net Present Value (NPV) of 17 million euros. The sensitivity analysis performed to compare different price scenarios for natural gas and electricity tariffs and to assess the impact of system charges in the economic evaluation shows that the 'high' case always has a lower payback time than the other cases. This shows that at elevated natural gas and electricity prices a district heating solution is always cheaper than an individual solution. Furthermore, the comparison between the co-generator solution and the heat pump solution showed that the solution without a co-generator and with only heat pumps is convenient when electricity taxes are zero or very low.

Geothermal energy, with its proven technology and abundant resources, can make a significant contribution towards reducing the emission of greenhouse gases worldwide. It is necessary for governments to implement a legal and institutional framework and fiscal instruments allowing geothermal resources to compete with conventional energy systems.

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